CONTENTS

HIGHLIGHTS A-1

I. GENERAL

ENERGY POLICY AND FORECASTS

CERA Sees Russia as Location for Last Great Oil Boom 1-1
Harvard Study Downplays Value of Strategic Product Reserves 1-3
NRC Cites Synthetic Fuel as Example of Unsuccessful Government Research 1-5
IEA Reports Fundamental Change in World Energy Balance Under Way 1-6
National Research Council Calls for Improved Energy Modeling Techniques 1-10

TECHNOLOGY

Consolidated Natural Gas to License Hydrocarbon Separation Technology 1-13
Progress Noted in Liquid Fuels from Syngas 1-13

GENERAL PUBLICATIONS/PATENTS

1-16

COMING EVENTS

1-17

II. OIL SHALE

PROJECT ACTIVITIES

Petrosix Commercial Module Approaching 4,000 Barrels per Day 2-1
Conversion of Unocal Upgrader to Methanol Plant Proposed 2-1
Joint Development of Oil Shale and Coal Proposed in South Australia 2-1
SPP Suffers Setback on Stuart Project 2-2

CORPORATIONS

Conoco Donates Oil Shale Records to Colorado School of Mines 2-4
North American Chemical Buys Interest in NaTec 2-4

TECHNOLOGY

Cold Flow Model of Circulating Fluid Bed Retort Tested 2-5
Fine Grinding Not Necessary for Short-Contact-Time Retort 2-6
Advanced Integrated Oil Shale Processing System Proposed 2-8
Damping Factors Improve Simulation of Oil Shale Blasts 2-10
Microwave Retorting Shows Advantages for Australian Oil Shale 2-11
Oxidation of Chattanooga Kerogen Sheds Light on Molecular Structure 2-13
INTERNATIONAL

Oil Shale Activities in China Updated
Fluidized Bed Retorting Enhances Yield of Moroccan Oil Shale
Co-Retorting of Torbanite and Cannel Coal Studied for Alpha Deposit
Queensland Oil Shale Resources Reviewed

ENVIRONMENT

Concept of Sustainable Development Explored for Oil Shale
DOE Issues Report on Environmental Analysis of Canceled Oxy Program
Bench-Scale Tests Show Reverse Combustion Effective at Removing MIS Organic Residue

RESOURCE

House Panel Approves Leasing Naval Shale Reserves for Gas Production

SOCIOECONOMIC

County Uses Unocal Funds for Research

OIL SHALE PUBLICATIONS/PATENTS

STATUS OF OIL SHALE PROJECTS

INDEX OF COMPANY INTERESTS

III. OIL SANDS

PROJECT ACTIVITIES

Peace River Reduces Operating Costs
Oil Sands Production Figures Updated
Fording-Kilborn Joint Venture to Test Oil Sands Process
Chevron Steepbank Project Uses 1,600-Foot Horizontal Section
Fire Damages Suncor Upgrader
September Startup Scheduled for UTF
First Tangleflags Horizontal Well Passes Million Barrel Mark

CORPORATIONS

AOASTRA To Commission 5 Tonne/Hour Taciuk Processor
OGJ Reports 24 Percent Increase in EOR Activities in 2 Years
Petro-Canada Cuts Work Force and Spending on Oil Sands
Murphy Oil Reports Little Heavy Oil Activity
Solv-Ex Looking for Financing for Bitumount Project

GOVERNMENT

New Oil Sands Research Program Authorized
ERCB Reviews Year in Oil Sands

ECONOMICS

Pelican Lake Horizontal Well Costs Down, Productivity Up
IV. COAL

PROJECT ACTIVITIES

Rosebud Syncoals Comes Onstream
Toms Creek Project Will Use U-GAS Process with Hot Gas Cleanup
Great Plains Keeps Gas Production Up, Sells Phenol
Status of CCT Coal Conversion Projects Updated

CORPORATIONS

Illinois Coal Waste to be Tested as Gasifier Feedstock
Companies Report Progress in Gas Turbines for Gasification Applications

GOVERNMENT

Illinois CCT Funding Earmarked for Two Gasification Projects
DOE Issues Draft Solicitation for CCT Round V

ENERGY POLICY AND FORECASTS

GE Sees Favorable Market Outlook for IGCC
Bechtel Outlook Calls for 180 Gigawatts of New Electrical Capacity by 2001

ECONOMICS

Chemical Coproduction with IGCC Promising if Gas Prices Increase
New Approaches Suggested for High-Value Chemicals from Coal

TECHNOLOGY

Integration of IGCC with Compressed Air Energy Storage Shows Promise
Silicon Carbide Candle Filters Making Progress in Hot Gas Cleanup
Ardelite Process Makes Aggregate from Gasifier Ash
Ranking System Developed for Coal Gasification Processes
New Sources for Coal Tar Chemicals May be Needed
INTERNATIONAL

IGT Licenses U-GAS Process for Chinese Trigeneration Project 4-35
Texaco Gasifier to be Used for Fertilizer Project in China 4-35
Carbogas Project in Spain will be International Effort 4-36
Coal Price Reform Causes Difficulty for Shanghai Gas Works 4-37
Coal/Water Slurry Fuel Being Produced at Two Locations in China 4-37

ENVIRONMENT

Externalities Analysis Favors Coal Gasification 4-38
Mutagenicity of Lurgi Coal Tar Fractions Studied 4-39

COAL PUBLICATIONS/PATENTS

COAL PUBLICATIONS/PATENTS 4-41

STATUS OF COAL PROJECTS

STATUS OF COAL PROJECTS 4-46

INDEX OF COMPANY INTERESTS

INDEX OF COMPANY INTERESTS 4-93

V. NATURAL GAS

PROJECT ACTIVITIES

Mossgas Expects to Produce First Synthesis Gas in June 5-1

GOVERNMENT

DOE Releases Draft of Natural Gas Strategy 5-3

ENERGY POLICY AND FORECASTS

NERA Lowers Gas Price Forecast 5-4

TECHNOLOGY

Combined Reforming and Partial Oxidation Gives Improved Route to Methanol 5-5
ACS Meeting Hears Progress on Direct Conversion of Methane to Liquids 5-5

INTERNATIONAL

Bolivia Set to Become Gas Exporter 5-9

RESOURCE

Canadian Excess Gas Deliverability to Remain for 2 Years 5-10

NATURAL GAS PUBLICATIONS/PATENTS

NATURAL GAS PUBLICATIONS/PATENTS 5-12

STATUS OF NATURAL GAS PROJECTS

STATUS OF NATURAL GAS PROJECTS 5-14
HIGHLIGHTS

Capsule Summaries of the More Significant Articles in this Issue

CERA Sees Russia as Location for Last Great Oil Boom

Cambridge Energy Research Associates (CERA) recently published World Oil Trends For The 1990s. In their overall outlook, CERA sees the oil industry shifting priorities, pointing to a resurgence of the international oil industry and a continuing contraction of the North American industry. Their assessment, on page 1-1, discusses how the Soviet Union could end up with the last great oil boom of this century.

Harvard Study Downplays Value of Strategic Product Reserve

A United States strategic product reserve would not be a viable economic consumer benefit, according to a Harvard study outlined on page 1-3. For a regional reserve to financially break even, there would have to be an oil supply disruption each and every year increasing the average cost of petroleum products by more than 18 percent. This would be unprecedented. Other questions are investigated such as when the government would use the reserve, whether the use would be cost effective, and how the nation would pay for a stockpile.

IEA Reports Fundamental Change in World Energy Balance Under Way

The International Energy Agency (IEA) foresees that the global energy balance will undergo a fundamental change (page 1-6). According to their energy outlook, substantially higher growth rates in non-OECD regions will mean that these nations will account for more than half the world energy demand by the mid-1990s. The increased competition for available energy supplies will demand greater cooperation in the exploration and development of energy reserves.

National Research Council Calls for Improved Energy Modeling Techniques

The United States Department of Energy should enhance the National Energy Modeling System (NEMS) within 1 to 2 years, according to the National Research Council (NRC). Presented on page 1-10 are the recommendations from NRC for the updated NEMS. A better modeling system would allow users to make sound energy investments in a way that addresses environmental and national security concerns in addition to producing a direct cost savings.

Progress Noted in Liquid Fuels from Syngas

Recent progress in several new or improved catalytic processes to produce fuel from syngas is reviewed on page 1-13. Shell Oil Company is pioneering the concept of carrying out syngas hydrogenation using a cobalt catalyst. Mobil Oil's methanol-to-gasoline process has been in operation in New Zealand for 6 years. Fuel Resources Development Company in Colorado is converting landfill methane to syngas and then to hydrocarbon fuels with a slurry catalyst technique.

Consolidated Natural Gas to License Hydrocarbon Separation Technology

Consolidated Natural Gas Company (CNG) is licensing a process called explosive shattering. As announced on page 1-13, CNG is offering a complete package to interested licensees. The patented technology uses a supercritical fluid to selectively reduce the hydrocarbon component to
micron-sized particles for more efficient use in coal gasification, liquefaction, and other fuel and chemical processing operations.

**Joint Development of Oil Shale and Coal Proposed in South Australia**

The Leigh Creek oil shale deposits overlie the Leigh Creek coal fields. Central Australian Oil Shale Pty. Limited has proposed the simultaneous development of the two resources. The company plans to process the shale to extract oil and other petroleum products. The coal would continue to be used in ETSA's Port Augusta power station. The article on page 2-1 presents the proposed mining plans for the joint development.

**Petrosix Commercial Module Approaching 4,000 Barrels Per Day**

The shale oil commercial module at Sao Mateus do Sul owned by Brazil's state oil company, Petrobras, is currently at 70 percent of the full-scale capacity. Total daily production is expected to reach 4,000 barrels of shale oil, 140 metric tons of fuel gas, 50 tons of liquefied petroleum gas and 100 tons of sulfur. The new module has been in operation since December 15 using the Petrosix shale processing technology. See page 2-1 for more information.

**Fine Grinding Not Necessary for Short-Contact-Time Retort**

A summary of the effects of retort process variables on shale oil yields in a short-contact-time (SCT) retort is presented on page 2-6. SCT retorting favors high-grade shale. The product yield is not affected by other variables such as particle size or heating time (1 to 6 seconds for all cases). Shale grade alone affected the ultimate yields of oil and coke.

**Advanced Integrated Oil Shale Processing System Proposed**

The basic building blocks for an oil shale industry in Western Colorado may include longwall mining/backfilling and hydoretorting of the shale. A description of this advanced integrated shale process is on page 2-8. In addition, the system components would include proven state-of-the-art raw and spent shale processing, and topping and bottoming the syncrude for feed to hydrogen and utilities production, respectively. The syncrude would be transported by pipeline in this proposed system.

**Microwave Retorting Shows Advantage for Australian Oil Shale**

Microwave retorted shale from Australia's Kerosene Creek deposit produces oil which has advantages over conventionally retorted oil in terms of its composition. The microwave retorting yields a greater portion of lighter hydrocarbons and lower sulfur and nitrogen than conventional retorting. The oil is readily hydrotreated to produce a synthetic crude oil which is a viable source of distillate fuels of specification quality. Results from these studies at the Microwave Applications Research Center are quoted on page 2-11.

**Oil Shale Activities in China Updated**

China has approximately 7.7 billion tonnes of shale in the Fushun and Maoming reserves according to the article on page 2-14. Total estimated resources reach 700 billion tonnes. Oil shale activities are expected to increase in the 1990s with the addition of new processing and power generation plants. The existing retorts will be modified to use newer technology. China plans to focus more attention on the production of wax and anticorrosive reagents.
Fluidized Bed Retorting Enhances Yields of Moroccan Oil Shale

Pyrolysis characteristics of Moroccan oil shale from the Timahdit and Tarfaya deposits were investigated in fixed-bed, nitrogen-swept and fluidized-bed pyrolysis. The effects of pyrolysis conditions on product yields and distribution of the pyrolyzed shales is noted on page 2-15. Fluidized-bed pyrolysis was found to enhance oil yields under moderate conditions. The yields ranged from 133 to 157 percent of modified Fischer Assay.

Co-Retorting of Torbanite and Cannel Coal Studied for Alpha Deposit

The flash pyrolysis of a 2:1 mixture of cannel coal/torbanite results in oil that contains components derived from both parent lithologies. As explained on page 2-16, the oil showed both the aromatic compounds derived from coals and the typical torbanite homologous alkene/alkane pairs. The tests will continue to determine if the mixture can be retorted on a larger scale.

Queensland Oil Shale Resources Reviewed

The oil shale deposits in Queensland, Australia hold an estimated 28.8 billion barrels of shale oil. The article on page 2-18 describes 12 deposits in terms of location, estimated area, and activity at the deposit. Approximately two-thirds of the total resource figure for Queensland is held in the four deposits of Condor, Yaamba, Rundle and Stuart.

DOE Issues Report on Environmental Analysis ofCanceled Oxy Program

Occidental Oil Shale, Inc. withdrew from its oil shale demonstration project near Meeker, Colorado in 1991. The environmental analysis of the project, however, was recently completed by the National Research Center for Coal and Energy. The report evaluates the environmental health and safety aspects of modified in situ and circulating fluidized-bed combustor technologies, which were planned for the demonstration plant. See page 2-24 for more details.

Bench-Scale Tests Show Reverse Combustion Effective at Removing MIS Organic Residue

Occidental Oil Shale, Inc. successfully demonstrated its modified in situ (MIS) technology at the Logan Wash oil shale retorting facility near De Beque, Colorado. The major environmental concern of that project was the impact of the process on local groundwater. To minimize water requirements, an effective method was sought to remove unretorted organic material at the bottom of the retort. Reverse combustion proved to remove all the residue, while the hot quench process left heavy oil residues. For details see page 2-26.

House Panel Approves Leasing Naval Shale Reserves for Gas Production

The United States House of Representatives Interior Subcommittee on Mining and Natural Resources has approved a bill to open two Naval Oil Shale Reserves to natural gas drilling and public access. The 55,000 acres would be managed by the Department of the Interior. If adopted the reserves would be opened for resource exploration with the exception of oil shale. For more details see page 2-28.

Peace River Reduces Operating Costs

The Peace River heavy oil sands project in northern Alberta, Canada reduced operating costs by 13 percent in 1991. This cost reduction helped offset lower bitumen prices during the year. By the
end of 1992, Shell Canada Limited expects to be operating with some 1,200 fewer full-time employees (see page 3-1).

**Oil Sands Production Figures Updated**

Synthetic crude oil production at the Suncor plant increased by 2 million barrels in 1992 compared to the previous year. Alberta Energy Resources Conservation Board statistics show that Suncor's syncrude production in January 1992 was 333,340 cubic meters, up from 265,083 cubic meters in December 1991. Synthetic crude production rates are summarized on page 3-1.

**Chevron Steepbank Project Uses 1,600-Foot Horizontal Section**

The Chevron Canada Resources Company HASDrive (Heated Annulus Steam Drive) project at Steepbank has continued to expand. Four pilot wells were drilled in August including a 1,600-foot horizontal well at a 2,800-foot depth. The article on page 3-2 states that the HASDrive well is expected to produce more than a conventional well.

**Fording-Kilborn Joint Venture to Test Process**

Bitmin Resources Inc., a joint venture company of Fording Coal Ltd. of Calgary, Alberta Canada and Kilborn Engineering and Construction Ltd., will invest C$10 million in oil sand extraction technology. The innovative Counter Current Drum Separator technology may reduce the cost of bitumen processing by $3 per barrel. See the details on page 3-2.

**OGJ Reports 24 Percent Increase in EOR Activities in 2 Years**

Oil & Gas Journal (OGJ) reports that worldwide use of enhanced oil recovery (EOR) techniques increased 24 percent from 1990 to 1992. The article on page 3-5 assesses EOR activities in the United States and in other countries. The United States EOR production rate has increased to 104,300 barrels per day.

**AOSTRA to Commission 5 Tonne/Hour Taciuk Processor**

The Alberta Oil Sands Technology and Research Authority (AOSTRA) 5-tonne per hour mobile demonstration Taciuk processor is complete (see page 3-5). The mobile oil sands thermal retorting plant will be used to demonstrate the commercial readiness of the process. The Taciuk process offers a 20 to 25 percent reduction in the cost of commercial processing, creating a pipelineable coker-type distillate without leaving tailing ponds.

**New Oil Sands Research Program Authorized**

The Canadian Government is joining with the Alberta Oil Sands Technology and Research Authority, the Alberta Research Council and industry to fund a new 5-year program in oil sands recovery. The $20 million program will generate new technology in order to reduce heavy oil and bitumen production costs. The research will be conducted primarily by the Alberta Research Council. Details of the program are on page 3-10.

**ERCB Reviews Year in Oil Sands**

The Energy Resources Conservation Board (ERCB) reviews Alberta's oil sands production. Although economic and environmental factors make the development of the province's huge oil
sands reserves more difficult, synthetic crude oil production reached a record 13 million cubic meters in 1991, as described on page 3-10. Crude bitumen production dropped almost 9 percent.

Pelican Lake Horizontal Well Costs Down

CS Resources Limited is currently operating 17 horizontal wells in a thin, heavy oil pool in the Pelican Lake area. The horizontal wells were drilled in three phases, and at each phase the company has been able to improve well costs and increase productivity. Presented on page 3-12 is the Pelican Lake area development history. The four Phase III wells, all drilled in 1991, contacted almost 100 percent of good quality reservoir throughout the horizontal section.

Bitumen Extraction in SESA Process Correlated with Asphaltene Content

As one method of avoiding the tailings problem associated with hot water extraction of bitumen from Athabasca oil sands, the Institute for Environmental Chemistry in Ottawa, Ontario, Canada has developed Solvent Extraction with Sand Agglomeration (SESA). This process, described on page 3-15, is a solvent extraction method which utilizes concurrent particle aggregation in order to overcome difficulties normally encountered in solvent-liquid separation in the presence of fines.

Bitumen Separated from Oil Sands by Ultracentrifugation

The Alberta Research Council has studied ultracentrifugation as a method to recover bitumen from oil sands. As explained on page 3-17, approximately 70 percent of the bitumen was recovered by this process. The resulting ultracentrifuged bitumen contained some emulsified water and a small amount of fine solids. The percent recovery could not be linked to oil sand grade.

Orimulsion Seen as Desirable Feedstock for Gasification

Using Orimulsion for gasification feedstock in an Integrated Gasification Combined Cycle (IGCC) plant offers all of the environmental and efficiency advantages of coal IGCC. In addition, according to the article on page 3-19, an Orimulsion IGCC may have an economical advantage over a coal-based IGCC plant, or a difference in cost of electricity of $0.005 to $0.01 per kilowatt-hour.

Utah Tar Sands Show Potential for High Density Jet Fuels

Jet fuel boiling range fractions obtained from native Utah bitumens show potential for use as high density jet fuel. Only mild hydrotreating is needed due to the naphthenic character of the fractions. Page 3-21 presents the results of the study conducted at the University of Utah. It was concluded that a high quality jet fuel boiling range fraction can be distilled from the native bitumen in low yield.

Toms Creek Project will Use U-GAS Process with Hot Gas Cleanup

Tampella Power Corporation has been chosen by the United States Department of Energy to build an IGCC demonstration plant in Coeburn, Virginia. The project, outlined on page 4-1, is called the Toms Creek IGCC project. It will use 430 tons per day of bituminous coal from an adjacent mine to produce 55 megawatts of electric power and 20,000 pounds per hour of steam. Additional power will come from a natural gas-fired combined cycle system.
Rosebud Syncoal Comes Onstream

The Rosebud Syncoal Partnership is in startup ahead of schedule. The Colstrip, Montana plant will demonstrate an advanced thermal drying and physical coal cleaning process that can reduce moisture and sulfur content of low-rank, subbituminous and lignite coals to enhance their thermal and environmental values. As discussed on page 4-1, the plant will produce 1,000 tons per day of upgraded solid fuel when operating at full capacity.

Great Plains Keeps Gas Production Up, Sells Phenol

The Great Plains Synfuel Plant near Beulah, North Dakota averaged 161.5 million cubic feet per day of synthetic natural gas production in January. The high production was attributed to maximizing the onstream factor and performance of all equipment. In addition, the plant produces 35 million pounds of phenol annually. A 2-year contract with Schenectady Chemicals in New York has recently been signed for 10 million pounds of phenol per year. See page 4-3 details.

Status of CCT Coal Conversion Projects Updated

Projects involving coal conversion as part of the United States Department of Energy's Clean Coal Technology (CCT) demonstration program are summarized starting on page 4-3. Ten projects demonstrating advanced coal conversion technology are discussed.

Illinois Coal Waste to be Tested as Gasifier Feedstock

The Center for Research on Sulfur in Coal is evaluating coal slurries for use in gasifiers built by Destec Energy, operator of the nation's largest slurry-fed gasifier. The United States Department of Energy is funding the demonstration project. See page 4-14 for a discussion of the gasification combined cycle technology which provides 40 percent efficiency. The use of coal slurries as feedstock is expected to open new markets for the state's coal mines, and provide environmentally sound and efficient powerplant technology.

Companies Report Progress in Gas Turbines for Gasification Applications

Summaries of the progress in gas turbines for gasification applications at several companies can be found on page 4-14. Westinghouse Electric Corporation is currently developing combustion turbines to be used in coal-fired combined cycle gasifiers. Shell Oil Company's gasifier has produced a medium-BTU gas which is an excellent fuel for gas turbines. General Electric Company also has a number of projects involving combined cycle power applications for their gas turbines.

DOE Issues Draft Solicitation for CCT Round V

The United States Department of Energy (DOE) has issued the draft solicitation for proposals for participation in the fifth round of the Clean Coal Technology Demonstration Program. See page 4-16 for a description of the current emphasis in Round V, which is the need for demonstrating technologies to enable utilities to meet the strict air emission standards in the post-2000 era. DOE's deadline for issuing the final solicitation is July 6, 1992.

GE Sees Favorable Market Outlook for IGCC

General Electric Company sees power generation from integrated gasification combined cycle as being economically competitive with conventional pulverized coal steam power generation. As
Bechtel Outlook Calls for 180 Gigawatts of New Electrical Capacity by 2001

Bechtel Power Corporation says that at a 3 percent per year average growth rate the nation will require additional electric generating capacity of 180 gigawatts by the year 2001. Bechtel's forecast on page 4-20 chooses gas in the near term, but coal toward the end of the forecast period, as the fuel of choice for power generation plants. Considering lead times, Bechtel estimates that 255 gigawatts must be ordered over the next 10 years.

Chemical Coproduction with IGCC Promising if Gas Prices Increase

The Electric Power Research Institute (EPRI) is designing a standard IGCC plant that integrates electricity production and coproduct chemical production. EPRI wants to minimize the cost of electricity generation by marketing the coproduced products. Industrial grade methanol, agricultural grade ammonia, and urea would be produced as the coproducts, as outlined on page 4-23.

New Approaches Suggested for High-Value Chemicals from Coal

See page 4-24 for Pennsylvania State University researchers' assessment of the production of high-value chemicals from coal. Aromatics, phenols, and heterocyclic compounds are among the target chemical groups. The authors discussed major problems facing the industrial utilization of coals in carbonization, combustion and liquefaction. Strategies for producing useful coal chemicals are discussed.

Texaco Gasifier to be Used for Fertilizer Project in China

China has selected Texaco's coal gasification technology for the Weihe Chemical Fertilizer Plant near the City of Xian. The plant will produce 300,000 tons per year of ammonia, which in turn will be used to produce 520,000 tons per year of urea fertilizer. Details are discussed on page 4-35.

IGT Licenses U-GAS Process for Chinese Trigeneration Project

The Institute of Gas Technology (IGT) has agreed to license its U-GAS technology for use in the Shanghai Coking and Chemical Company Trigen Project. Trigen will produce town gas, chemicals, and electricity. A description of the U-GAS process is on page 4-35. Trigen represents the first commercial introduction in China of IGT's advanced fluidized-bed gasification process.

Carbogas Project in Spain will be International Effort

The Carbogas Project will demonstrate IGCC technology at a site in Puertollano, Spain. The project, discussed on page 4-36, comes within the framework of the Thermie Program of the European Community and will be undertaken by a consortium of utility companies in Spain, France, Portugal and Italy. Germany, England and Belgium will supply products for the project's construction.

Coal/Water Slurry Fuel Being Produced at Two Locations in China

A coal/water mixture, or liquefied coal, is being manufactured in Mentouga (western Beijing) and in Yanzhou (Shandong Province). The Mentouga plant will process 250,000 tons of liquefied coal...
per year, while the Yanzhou plant has the same 250,000 ton capacity and is expected to increase to 1 million tons over the next 3 years. As explained on page 4-37, Yanzhou is exporting the slurry fuel to Japan.

**Externalities Analysis Favors Coal Gasification**

Coal gasification combined cycle technology has lower externality costs than other coal-based technologies, according to Putnam, Hayes and Bartlett, Inc. The article on page 4-38 defines an externality as a cost imposed on society by an individual or firm where that firm does not pay the cost, such as pollution damage to crops. Coal gasification combined cycle is one technology that may be considered when more significant environmental externality regulations are required.

**Mossgas Expects to Produce First Synthesis Gas in June**

Mossgas, Ltd., using Sasol Synthol technology, expects to begin synthesis gas production in June. Gas reserves located 55 miles off the coast of South Africa will provide feedstock for 30 years at design rate. According to the article on page 5-1 the project now requires a $35 per barrel equivalent crude oil price to provide a 15 percent nominal return on funds invested.

**DOE Releases Draft of Natural Gas Strategy**

Delivery and storage research and development are new components of the United States Department of Energy's gas program. The proposed strategy discussed on page 5-3 calls for continued efforts to reform federal and state regulations that restrict market opportunities for natural gas. In addition, the strategy emphasizes programs to improve utilization, delivery and storage of natural gas and refocuses on-going supply-related research and development to meet near- and mid-term needs.

**NERA Lowers Gas Price Forecast**

National Economic Research Associates, Inc. (NERA) forecasts wellhead prices to average $1.50 per thousand cubic feet of natural gas in 1992. This is a significant drop from NERA's earlier forecast of $1.70, as discussed on page 5-4. Comparatively, the 1993-1995 price projection is also lower. The outlook report points out, however, that natural gas, like metals, can be boom-or-bust and that a sharp market upswing for the industry may occur.

**ACS Meeting Hears Progress on Direct Conversion of Methane to Liquids**

The rising demand for ethylene and higher olefins is another incentive to develop a direct methane conversion process, states the article on page 5-5. Research by Mobil Research and Development, CSIRO Division of Coal and Energy Technology and Amoco Oil Company's Research and Development Department is summarized, covering topics of methane conversion rates, formation of methyl radicals, selectivity to C₂ hydrocarbons and general observations and remarks.

**Bolivia Set to Become Gas Exporter**

Bolivia's state-owned oil and gas company, Yacimientos Petroliferos Fiscales Bolivianos (YPFB), is negotiating contracts for natural gas with Argentina and Brazil. The article on page 5-9 states that additional countries, Chile, Paraguay, Peru and Uruguay, may also negotiate for natural gas contracts. Bolivia plans to expand its current production of 530 million standard cubic feet per day. YPFB foresees the industry reaching 4.4 trillion standard cubic feet.
ENERGY POLICY AND FORECASTS

CERA SEES RUSSIA AS LOCATION FOR LAST GREAT OIL BOOM

Cambridge Energy Research Associates (CERA) recently published World Oil Trends For The 1990s. In their overall outlook, CERA sees the oil industry shifting priorities, pointing to a resurgence of the international oil industry and a continuing contraction of the North American industry.

In response to the Gulf crisis of 1990-1991, Saudi Arabian production in 1990 hit 8 million barrels per day, the highest level since 1981. Overall, world oil production in 1990 ended up 1 percent higher than in 1989, and marked the first time that it exceeded the level recorded at the beginning of the 1980s. The increases were accounted for primarily by OPEC production (Table 1). Non-OPEC production, as a whole, declined slightly—reflecting the continuing falloff of output in the two big "losers" of world supply, the United States and the former Soviet Union (Table 2).

The area of greatest interest for new oil development is, even more so than before, the republics that constitute the Commonwealth of Independent States. Here may be found the next "surprise" in world oil, as well as the "next prize," says CERA. The old Soviet Union is now out of business, a part of history. The constituents are undergoing a tumultuous transition to new systems, but the process is riven by political, economic, and ethnic conflicts. The outcome will determine whether Western companies do or do not undertake investment in the former Soviet Union.

The oil industry of the former Soviet Union remains the world's largest. But it is suffering from the same problems that are afflicting the overall economy—poor organization, shortages, poor morale, inefficient and inadequate investment, and technological backwardness. The effects can be seen in crude oil production (excluding natural gas liquids), which has fallen by about 20 percent since 1988—from 11.8 million barrels per day in 1988 to 9.6 million barrels per day at the end of 1991.

Export levels have fallen by something on the order of 50 percent—from 4.1 million barrels per day in 1988 to below 2 million barrels per day in the latter part of 1991, although the greatest part of this fall was in exports to Eastern Europe. Exports to "hard currency" customers remain

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Source: World Oil Trends
TABLE 2
NON-OPEC CRUDE OIL PRODUCTION
(Million Barrels per Day)

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<td>36.91</td>
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Source: World Oil Trends

relatively stable. These exports of oil (along with gas) are the main "cash crop" of the former Soviet Union, the lifeline to imports of Western technology and food. Until recently, the decline was not having as deleterious economic consequences, in terms of hard currency, as might have been imagined, owing to the fact that the decline had mostly been in the non-hard currency sales to the former Soviet client-states in Eastern Europe.

But the gains to be had from selling oil at world prices on the international market, as opposed to the artificially low prices on the domestic market, are so great that a variety of private, semi-official entities began selling oil directly in 1991 outside the traditional monopoly of Soyuz-Nefteeksport. Estimates are that as much as 20 to 25 percent of export volumes, primarily in the form of petroleum products, are being sold through these alternative entities. In November 1991, the Russian Republic, where 90 percent of the oil is produced, canceled export licenses and plans to issue tougher regulations in 1992. But, in reality, these controls will be difficult to enforce. The struggle over hard currency earnings generated by oil is likely to be a continuing feature of the new systems.

An additional factor in the export equation of the former Soviet Union is the uncertainty regarding the continuing decline of internal consumption due to economic chaos. During 1991, production and domestic consumption were falling at almost the same rate. How much further domestic consumption can fall will, in part, affect the volumes of oil available for export.

In spite of all the obvious obstacles to investment in the Soviet oil industry, the interest on the part of Western companies is high. The simple reason is that the opportunity, from a geological standpoint, continues to grow as geological investigation continues. For many years, the "official" Soviet oil reserves number was a state secret. The "unofficial official" number in the CERA report is some 57 billion barrels. However, geological research over the last 2 years is leading to a view that, when properly explored with advanced technology, the Soviet reserve base will prove to be much more prospective—perhaps even on the Saudi scale (though hardly so convenient or inexpensive to produce). That is driving the intensifying interest of Western companies.

Yet a basis for the reintegration of the new republics into the world oil industry does not exist and will not exist until
the legal and contractual foundations are put into place. For any significant activity to take place, companies will require some sense of security for their operations and some clear basis that will ensure a return on their investment. So far, North American and European companies are taking the lead. Although the Japanese firms appear to be waiting for greater clarification, they will bring to the table two important elements: capital and a nearby market with a compelling need—even more so for gas than for oil.

Western governments—eager to see democratic, market-oriented republics emerge out of the wreckage of the Soviet Union—recognize that the sector most amenable to Western help, and therefore most likely to produce quick results, is energy. Thus, they will be adding to the support for the opening of the Soviet oil and gas industry to international investment.

CERA says that despite all the obstacles, the makings are present in the Soviet Union for a great oil boom. Such a prospect holds many ironies. It was, after all, the development of Russian oil resources around Baku in the 19th century—resulting from the Czar's opening up the region to private investment—that broke the grip of Standard Oil and John D. Rockefeller on the world market. And, while there will be many "hot spots" for oil development around the world in the 1990s, it is striking that this broad expanse of landmass (one-sixth of the world's surface) which used to be the "motherland of socialism," could well end up as the last great oil boom of the 20th century.

The European Energy Bridge

The European Energy Charter represents, in part, an effort to facilitate the reintegration of the former Soviet Union and the new republics into the world oil industry and to provide the required basis. If carried out, the charter would aid the evolution toward market economies for the former East Bloc countries by using energy as a lever. The charter aims to create an "energy bridge" across Europe, to provide the framework of commercial law required for energy investment and to lay a foundation for the evolution of the successor states to the Soviet Union by encouraging development and marketing of those states' energy resources to help shore up political stability. The year 1992 will be critical for the enactment of the Energy Charter—taking the charter from a non-binding political statement to a legally binding "Basic Agreement" on overall protocols and eventually to sector-specific protocols governing oil, natural gas, and nuclear investment. If not merely signed but truly implemented, it could transform the global energy business by establishing a "Greater European Energy Community" and by expediting the economic transformation of the former Soviet Union.

Individual OPEC countries have begun to reexamine their own position vis-a-vis foreign participation. OPEC countries are in a real race for capital to help expand their own production capacity. Venezuela has taken steps to open some of its upstream operations to foreign participation. Algeria moved very aggressively during the second half of 1991, but the uncertain political situation in this country suggests that some of the changes may be conditional and that political, economic, and social risks will be greater. OPEC's decisions regarding capacity expansion and the relative pace of the race between supply and demand will drive the price of oil over the decade.

####

HARVARD STUDY DOWNPLAYS VALUE OF STRATEGIC PRODUCT RESERVES

H. Lee, et al., from the John F. Kennedy School of Government recently released a study investigating regional strategic product reserves as part of the United States strategic petroleum stockpile program. The issue, debated since 1975, is integral to energy policy.

Certain states perceive themselves as being disproportionately vulnerable to disruptions in oil markets, either as the result of war, weather, or in some instances accidents, such as the Valdez oil spill. Elected officials representing these states have lobbied hard for the establishment of a Regional Product Reserve (RPR).

According to the study, while proponents have periodically changed their arguments, enthusiasm for a product reserve has remained constant, especially among the northeastern states. These arguments have ranged from minimizing the impact of price increases to offsetting logistical rigidities by "forward positioning" crude oil in the form of product. Still others have argued that the reserve would provide important social welfare benefits to needy consumers.

In the fall of 1990, the Kuwait and Iraq conflict ignited another round of Congressional debate on this subject, resulting in legislation ordering the Department of Energy to conduct a 3-year test of a product reserve. The authors conclude in their assessment, that strategic product reserves would not be a viable economic consumer benefit.

Criteria for Developing Product Reserves

According to the study, in order to justify building a strategic stockpile for any commodity, five criteria must be met:

- Options for diversifying supply sources of the commodity in question—in this instance, oil products—must be limited or nonexistent.
- The country must be disproportionately reliant on the commodity—to the extent that this reliance makes it economically and strategically vulnerable to a disruption.
Substitutes must either be unavailable or be prohibitively expensive.

The probability of a disruption must be high.

The government is able and willing to use the stockpile, if it is established.

Crude oil meets at least the first four of these criteria. The case for oil products is not as evident. It is true that there are limited substitutes for some products such as airplane fuel, but even when there are substitutes, conversion takes time and money. Yet, if one looks at the other criteria, the arguments in favor of a product reserve begin to weaken, says Lee.

Investigating the Criteria

Options for Diversification: There is no concentration of refining facilities in any one region of the world. The United States refines approximately 85 percent of the products it consumes and imports the remainder from over 25 countries. If refineries in any single country are disrupted, the United States should be able to obtain products from other nations at a small premium.

Regional Dependence: Though there are states which rely more heavily on certain petroleum products, a cursory glance at historical consumption patterns clearly demonstrates that the supply and demand for individual products is extremely dynamic. A state which is presently reliant on any particular petroleum product may not be overly dependent on that product 5 years from now. Further, any regional reserve which provides benefits exclusively for one specific part of the United States will have difficulty obtaining support from taxpayers located in other areas.

Probability of a Product Disruption: There are three possible causes of a product disruption: 1) a cut-off in crude oil which deprives refineries of their feedstock; 2) a dramatic increase in demand caused by unusual weather patterns; and 3) the elimination of refinery capacity by accident, war, or terrorism.

The probability of future crude disruptions remains high. In such instances, however, refineries will have more, rather than less, capacity to produce products. Weather induced disruptions—which have occurred twice in the last 10 years—are difficult to predict and tend to last only 3 to 4 weeks.

A disruption in refinery capacity by terrorism would create significant problems. In this case, the availability of a product reserve would produce measurable benefits. However, the likelihood of such an incident is extremely low, given the geographic dispersion of refining infrastructure.

Will Government Use the Reserve: The final criterion deals with the willingness of governments to use an established strategic reserve. The traditional reluctance of the United States to use the crude product reserve should not give advocates much confidence that the situation will change with a regional reserve. The authors feel that if the federal government is going to pay to establish the reserve, clearly it will retain the option of managing that reserve. Consequently, it is unlikely that the criteria used to drawdown the regional reserve will be significantly different than that used for the federal crude reserve. Further, because the former will be substantially smaller than the latter, concern about depleting the supplies prematurely will limit the willingness to rapidly drawdown the reserve to meet a crisis. Table 1 shows the price impact of the release of distillate stocks according to the quantity released, estimated consumption, and the effective price drop.

Costs and Benefits

For a regional reserve to financially break even, the study concludes that there would have to be a disruption each and every year and the disruption would have to increase the average cumulative price of products such as heating oil by more than 18 percent. Only under such an assumption will the sale of product from the reserve provide sufficient revenues to negate the need for government subsidies. In recent years, there has been no increase in United States product prices of this magnitude and frequency, independent of a disruption of crude oil.

Will a Reserve Lower Prices: Using conservative assumptions, a small reserve of 2 million barrels would have almost no effect on product prices during a disruption. A larger reserve of 15 million barrels would reduce product prices approximately 4.3 percent in a relatively responsive market to as much as 22.9 percent in an extremely unresponsive market.

One of the central issues in developing an efficient reserve operation mechanism is the need for an automatic trigger to release the stockpiled product. Product disruptions have historically unfolded suddenly, lasted for a short duration, and then receded as rapidly as they developed. For the reserve to be of any utility it must be released while product prices are on the upswing. The idea being to arrest the price run-up in its infancy. Implicit in this is a response measured in days. Any delay will subject the consumer to high prices without realizing the benefit the reserve was instituted to provide.
TABLE 1

PRICE IMPACT OF RELEASE OF DISTILLATE STOCKS

Percent Price Drop = \( \text{Stock Release as \% of Consumption} \) 
\( \times \text{Supply Elasticity \times Demand Elasticity} \)

Average U.S. Consumption during December/January
- Daily: 3.12 mb
- Weekly: 21.8 mb
- Monthly: 93.6 mb

Elasticity of Supply = 0.1

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<th>Price Drop</th>
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Elasticity of Demand = 0.1

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<td>- One Month</td>
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Source: H. Lee et al.

###

NRC CITI ES SYNTHETIC FUEL AS EXAMPLE OF UNSUCCESSFUL GOVERNMENT RESEARCH

A study initiated by the National Research Council (NRC) says the government's attempt to develop a synthetic fuels industry is a "case study of unsuccessful federal involvement in technology development." The results of the study are reported by the Panel on the Government Role in Civilian Technology in "The Government Role in Civilian Technology: Building a New Alliance."

According to the report, the time needed to go from product design to commercialization in some important United States industries significantly exceeds that of foreign competitors. The new competitive environment for technology development means that continuous improvements in manufacturing process technology by United States firms will be necessary.

The panel believes that modifications in federal technology policies can strengthen national performance in civilian technology and enhance long-term economic growth. The United States can strengthen technology commercialization at the stage prior to that at which private firms invest in commercialization activities, through federal action to facilitate pre-commercial research and development (R&D). The United States can construct a technology policy that avoids direct subsidies for firms and industries, while at the same time supporting and leveraging United States comparative advantages in technological innovation.

Synthetic Fuels

In 1980, Congress established the Synthetic Fuels Corporation (SFC), a quasi-independent corporation, to develop large-scale projects in coal and shale liquefaction and gasification. According to the panel, most of the projects centered on basic and conceptual work that would contribute to demonstration programs in later stages, although funds were expended on several prototype and full-scale demonstration projects. The SFC was intended to support projects that industry was unable to support because of technical, environ-
mental, or financial uncertainties. Federal loans, loan guarantees, price guarantees, and other financial incentives totaling $20 billion were authorized to spur industry action. Although the SFC was designed to continue operating until at least 1992, the collapse in energy prices, rising environmental concerns, lack of support from the Reagan administration, and administrative problems ended the synthetic fuels program in 1986.

According to the report, the failure of the federal government’s effort to create a synthetic fuels industry yields valuable lessons about the role of government in technology innovation. The synthetic fuels program was established without sufficient flexibility to meet changes in market conditions, such as the price of fuel. An emphasis on production targets reduced research and program flexibility. The synthetic fuels program did demonstrate, however, that large-scale synthetic energy projects could be built and operated within specified technical parameters.

Energy programs of that time were hindered by excessive political interference, says NRC. Political influence on funding allocation decisions, selection of R&D projects, or the direction and conduct of scientific research are counterproductive to the success of federal technology efforts. The Clean Coal Technology project was hampered by Congressional involvement in technical design and operational management. Although some programs, such as the tertiary oil recovery initiative attained some technical success, the technology was not widely adopted.

Conclusions

The NRC panel concluded that substantial changes need to be made in the framework that supports civilian technology development in the United States. There have been fundamental post-war changes in the economic and technological environment in which United States companies compete. While there have been great benefits from federal support of basic scientific research, the panel believes that the almost exclusive focus of federal technology policy on investments in basic R&D needs to be modified.

A new federal role in support of private technology efforts should be shaped through investments in pre-commercial R&D, as well as projects to increase the rate of technology adoption in United States firms, says NRC. These are the areas where there is a potential for great public benefit, and United States firms cannot appropriate sufficient economic benefits from private investment.

A strengthened federal role in civilian technology and re-orientation of government policies beyond investment in basic scientific research will require more than simply changes in technology transfer policies or additional federal funding for pre-commercial activities. A significant new emphasis is needed on the performance and ability of United States firms to adopt new technologies. Although United States performance in technology generation remains strong, the nation’s industries are having increasing difficulty incorporating new technology into the production process, particularly the rapid introduction of incremental improvements in product and process technologies.

Recommendations

The panel considered options for a mechanism through which the federal government might extend its role in civilian technology. The panel has recommended the establishment of the Civilian Technology Corporation (CTC) as the most appropriate new mechanism for substantial federal investment in pre-commercial technology.

The panel believes that the CTC would offer a means to rationalize federal investments in non-military technologies in a systematic fashion.

The CTC would be a private, quasi-governmental institution intended to guide financial support for middle-ground, pre-commercial R&D in key technology areas of significance to the United States technology base. Financing for the CTC would be made available through a one-time appropriation by Congress of $5 billion. The $5 billion, if it were invested at a relatively rapid rate, would provide the capital necessary for up to approximately $1 billion in program expenditures per year. Funds might be allocated to firms by direct investment; they might also be distributed on a contract basis or, in the case of loans and loan guarantees, administered by the CTC through financial institutions selected by the board.

This funding level would enable the CTC to make the necessary investments to affect technology commercialization rates in the United States in a wide range of sectors, says NRC.

###

IEA REPORTS FUNDAMENTAL CHANGE IN WORLD ENERGY BALANCE UNDER WAY


Energy demand in non-OECD countries was almost equal to that of the OECD group in absolute terms in 1989. According to the report, the substantially higher growth rates in the non-OECD region will ensure that, by the mid-1990s, these
countries will account for more than half of world energy demand. Together with the increasing dominance of non-member countries in world energy production, IEA feels that this fundamental alteration in the global energy balance is essential to an understanding of likely energy developments in the coming years.

Fundamental changes in the world energy balance will have potentially significant implications for the way in which OECD countries deal with their energy requirements. It is unlikely, however, that the major energy challenge which these countries have faced over the preceding years, i.e. the assurance of secure energy supplies, will change. As a net importer of energy the OECD has long been faced with the security issue and has sought to deal with it in a number of ways. In particular, it has established emergency measures to deal with potential oil supply disruptions, has encouraged the diversification of fuel sources, the development of improved energy conversion and end-use technologies and has fostered improvements in energy efficiency. These will continue to be important planks of OECD energy policy and probable developments in the energy outlook are likely to intensify efforts towards their achievement. Of particular significance in this regard will be the continued importance of oil as a primary energy source, the increased concentration of available and "economic" oil supply capacity in the Middle East Gulf region and the likely ongoing fragility of political and economic relations in this part of the world.

Recent international events and trends could provide both the impetus and the opportunity for OECD countries to enhance their relations with non-members. A disturbing development, in IEA's view, has been the increasing respectability given to the notion that energy security and market "stability" ought to be sought in a regional rather than a global context. Regionalization initiatives which seek to restrict market access, either directly or indirectly, to a specific group of countries, however defined, will inevitably lead to trade distortions and associated losses in economic efficiency.

There are two additional energy issues. The first of these is the impact of environmental concerns on energy production and use. Energy-related environmental issues range from urban air pollution, and transboundary issues such as acid rain, to global questions including ozone depletion and climate change. The environmental issue brings to light the commonality between energy producers and consumers and

SYNTHETIC FUELS REPORT, JUNE 1992
between competing groups of consumers. The increased competition for available energy supplies will demand greater cooperation in areas of the exploration and development of energy reserves. The phenomenon of climate change from greenhouse gas emissions illustrates the futility of any one country or even group of countries acting individually to solve the problem.

IEA maintains that for the OECD it will not be possible to remain isolated from developments in non-member countries. For OECD countries this change will demand a global view which recognizes that developments in non-member countries will have an equally important impact on the global energy balance and, hence, the energy situation in OECD countries. This is likely to lead to increased linkages between the two regions, particularly in the areas of investment, technology sharing or more direct cooperation agreements, especially in relation to environmental problems.

**Major Changes in Regional and Fuel Demand Structures**

The major changes in regional and fuel demand structures which are expected over the period to 2005 can be placed in perspective after reviewing the past trends. While oil's share of both OECD and non-OECD energy demand will continue the decline evident in recent years, it is expected to remain the dominant fuel, accounting for 35 percent of global energy demand. Its weight in the various regions is expected to vary from 26 percent in the USSR and eastern Europe to 36 percent in the developing countries and 40 percent in the OECD. The impact of declining oil production levels in the USSR in the medium term and rapidly rising demand in the Asia-Pacific region will be to increase the global competition for available oil supplies. Africa and Latin America may become alternative competitive suppliers to the Middle East but this will depend on the future path of oil prices. It is inevitable that the Middle East region will continue to dominate global oil production and that OECD countries will rely on this region for up to 70 percent of their imports.

 Coal is expected to remain an important source of energy in the non-OECD area, particularly in the USSR, eastern Europe, China and parts of the Asia-Pacific region. Growth in consumption reflects the dominant consumer—the power generation sector.

The non-OECD is also likely to increase its share of global coal production to 63 percent by 2005. Environmental con-
cerns will be the major constraint on the increased use of coal. These constraints will initially be felt to a greater degree in OECD countries but will also operate in certain non-member areas. The extent to which coal consumption in non-member countries is affected by environmental considerations will depend upon international agreements.

Natural gas is expected to be the fastest growing component on non-OECD energy demand in the period to 2005 and will represent about 25 percent of total primary energy supply (TPES) in that year. The highest rate of growth in consumption is expected to occur in developing countries, especially the Middle East, where gas is being substituted for oil in power generation and industry in order to free oil for export.

At the regional level, although the USSR and China will remain by far the largest consumers of energy in the non-OECD world, the major growth in energy demand is expected to occur in the Middle East and the Asia-Pacific region. In the Middle East this will be accompanied by substantial increases in oil and gas production, more than sufficient to fuel the rapid expansion of a domestic energy-based industrial sector. As a result, the Middle East's potential as a supplier of energy to the OECD is likely to increase. By 2005, about 43 percent of world oil production will be sourced from this region and its exportable surplus will have more than doubled.

In the Asia-Pacific region, energy demand will be fueled by rapid rates of growth in both economic output and the population level. Coal and, to a decreasing extent, oil will remain the principal elements of the fuel structure and gas will become more important over time. As a result of its limited indigenous oil and coal reserves, the region is expected to become increasingly dependent on imports of these fuels.

In Africa, a small number of countries account for the major share of commercial energy demand and production. In the remaining countries, traditional (or non-commercial) forms of energy represent a substantial proportion of energy supply. It is expected that the major African countries will generate an increasing exportable oil and gas surplus despite increasing demand. With the likely re-integration of South Africa into the international trading environment, it is also possible that the region will become an increasingly important supplier of coal to the international market.

The Latin American region is also expected to increase its exportable energy surplus, mainly of oil but with potential also in the coal market. Because of its geographic proximity, the implications of this development for OECD countries are likely to be strongest for the North American economies and it is possible that Venezuela, in particular, will form a viable source of supply to this region.

In the USSR, the major political and economic changes taking place create an enormous degree of uncertainty about the future. Although frequently hampered by outdated equipment and practices and shortages of investment funds, the USSR remains the world's largest producer of energy. Vast reserves of coal, oil and gas remain untapped. Assuming the ultimate success of the reform program, it is possible that the USSR will become a larger player in international energy markets, especially as it shifts its currently substantial trade with the eastern European region towards alternative, hard-currency markets.

Eastern Europe's dependence on imports of energy is expected to increase in the medium term as demand growth will consistently outpace increases in indigenous production. Coal is expected to remain the major element in the eastern European energy balance and, as a consequence, environmental problems are likely to be significant.

Projected economic and population growth in China and its concomitant energy requirements will ensure that the country remains a dominant factor in global energy consumption. Although environmental issues are becoming an increasingly important concern for policy makers, coal is expected to continue to dominate the fuel structure.

Responding to the Global Energy Security Challenge

One of the IEA's major conclusions is that there will be increasing pressure on available energy resources. This increasing pressure or competition for energy supplies will affect all regions, whether net exporters or importers of energy. The implications for energy security will also be widespread. While OECD countries have already developed policies and mechanisms to deal with the security issue, in the majority of non-OECD countries the problem has yet to be dealt with comprehensively. This is all the more important as non-OECD countries are expected to account for by far the larger proportion of incremental energy demand in the coming years. However, the demands of economic and social progress in the non-OECD world are likely to leave few alternatives to increased energy consumption.

An area which offers major opportunities to achieve development objectives, while containing growth in energy consumption, is through improving the efficiency of energy use. An improvement in efficiency can be considered as an alternative "supply" of energy which can be "produced" by consumers. It has the additional advantage of being environmentally benign. This view of efficiency as an alternative energy supply is one which has underpinned OECD-country policy making for many years. The potential impact of efficiency improvements on global energy demand levels, however, is much greater in non-member countries. This is, first, because of their greater contribution to incremental energy demand and, secondly, because many of the opportunities for efficiency gains in OECD countries have already been realized. The achievement of global energy security and environmental objectives will be enhanced, therefore, if efforts
to improve efficiency are increased in the non-member world.

The second major mechanism by which global energy security might be enhanced is the continued diversification of fuel sources away from oil. In OECD countries, the share of oil in the fuel structure has fallen considerably since the first price shock of 1973-74 but the trend has been less pronounced in the non-OECD region. Oil still represents about 35 percent of non-member primary energy consumption and is likely to be about 32 percent in 2005. Given the current level of available energy technology and the continuation of current environmental policies, it is unlikely that fuel diversification outside these limits will occur in non-OECD countries. Within the OECD, however, governments are giving increasing attention to renewable energy technologies in recognition of the sizeable potential contribution they can make in the longer term to furthering energy security and environmental protection. In the case of non-OECD countries, the increased utilization of renewables could play a substantial role in achieving the same objectives. A major impediment to the expansion of renewables in these countries is the lack of accessibility to appropriate technologies at economic prices.

Despite the obvious advantages of diversifying the fuel mix, it would be a mistake to consider fuel diversification strategies from this point of view alone. Energy security will be enhanced equally by strategies to diversify the sources of supply of any particular fuel but particularly of oil. The energy security implications of heavy dependence on oil for example, can be reduced by developing a range of alternative oil supply sources.

Overcoming the Barriers to Improved Energy Efficiency and Fuel Diversification—the Role of Energy Technologies

Much of the work on improving energy technologies, especially in basic research, is undertaken in the industrialized countries of the OECD. The near absence of research and development (R&D) activities in developing countries is usually the result of a lack of financial resources and, often, the necessary technical skills. As a consequence, non-OECD countries are highly dependent on the development and dissemination of technology by member countries. It is often found that the application of new technologies in developing countries can only be achieved after a considerable amount of adaptation to local conditions. Equipment in developing countries, for example, often needs to be capable of operating with minimal maintenance and of withstanding fluctuating voltages in power grids. Many technologies also need to be demonstrated in order to establish operating parameters and costs.

While a variety of new technologies might be available to developing countries, their "accessibility" is often limited. A major factor constraining accessibility is the lack of information transfer mechanisms such as training programs. A second component of information transfer is the ease with which information on energy technologies can be identified and disseminated. In addition, in many developing countries, the institutions necessary for R&D to make a contribution are often ineffective or even missing. This is particularly the case where there is no efficiently functioning system of patents and intellectual property rights. Many industrialized country suppliers of energy technologies have been reluctant to provide technology to countries without the protection provided by a patent system. Until some of these barriers are overcome, the potential contribution of new technologies to energy efficiency and fuel diversification will remain substantially under-realized.

###

NATIONAL RESEARCH COUNCIL CALLS FOR IMPROVED ENERGY MODELING TECHNIQUES

The United States Department of Energy (DOE) must move quickly to enhance its computer modeling capabilities, building on existing models to configure a new National Energy Modeling System (NEMS) within the next 1 to 2 years, a committee of the National Research Council has concluded.

Such a system would help policy-makers analyze various energy scenarios and policy options, including any follow-on to the first National Energy Strategy introduced by President Bush last year, the committee noted in its report, "A Review of the National Energy Modeling System."

The report recommends development of a National Energy Modeling System within the Energy Information Administration (EIA)—an independent, non-advocacy unit of DOE. The system would help assess alternative energy options and policies as well as any associated economic, environmental, and national security impacts. Initially, system development should focus on strategic analysis for the mid-term time horizon (between 2 and 25 years), the report states.

Recommendations for a National Energy Modeling System

The federal government must analyze alternative policies and their implications for energy supply and demand—as well as potential impacts on the environment, the economy, and national security. The new Research Council report offers a framework for enhancing DOE's policy analysis and strategic planning capabilities through improved computer simulation technologies.

Building on existing EIA models would offer the fastest and most efficient means of development, the committee concluded. Proposing an organizational culture that is "outward-looking and ensures greater intellectual and institu-
national commitment," the report calls for a cooperative development effort between EIA and various relevant public and private groups.

Capabilities Outside DOE

The great diversity and importance of the energy system to many different groups has resulted in a variety of special and general-purpose energy models and tools. The many energy modeling capabilities outside of DOE and EIA include baseline forecasts of the national economy by private econometric firms, such as Data Resources, Inc. (DRI), Wharton Economic Forecasting Associates (WEFA), and public agencies, such as the Congressional Budget Office and Office of Management and Budget, develop basic information on economic growth, inflation, and employment, which helps quantify trends affecting energy demand.

A small number of general-purpose energy modeling systems provide periodic forecasts that broadly consider the total energy market but also have a sectorial or geographic emphasis, for example:

- The Gas Research Institute's annual baseline forecasts for energy, which strongly emphasizes natural gas, particularly new supply areas and technologies
- The California Energy Commissions' biannual outlook for energy which emphasizes the environmental, market, and supply concerns of the state
- The Northwest Power Planning Council's and the Electric Power Research Institute's models.

A great variety of special purpose energy models and studies examine in detail a specific fuel or demand sector, for example:

- Biennial estimates of the United States gas resource base are reported by the industry-sponsored Potential Gas Committee.
- The assessments of regional electric system reliability are provided by the North American Reliability Council.
- Various general and special-purpose energy models and forecasts are provided by think tanks, consulting firms, nonprofit organizations, and energy companies. Some of these models, data and forecasts may be useful as inputs for some types of NEMS analyses.
- Various international organizations, including the United Nations, the International Energy Agency, and the Organization for Economic Cooperation and Development, provide models and data useful for domestic energy analysis.
- Other government agencies carry out modeling, especially the Environmental Protection Agency with regard to environmental modeling.

Even this brief list shows that considerable energy modeling capability exists outside of the DOE—capability that often covers geographic, technological, or sectoral information in great detail, and which may be useful for NEMS analyses at DOE/EIA.

The report's primary recommendations fall into three categories related to development: timing, management, and design.

- Timing. EIA and DOE are encouraged to develop, within the next 1 to 2 years, sufficient computer modeling capabilities to support the development of the next National Energy Strategy.
- Management. To ensure impartial administration, the National Energy Modeling System should be placed exclusively under EIA's umbrella. An advisory council of potential system users should be established to bring together representatives of DOE, other federal, state, and regional agencies, and private organizations. The committee urged EIA to recruit and retain a highly skilled professional staff.
- Design. Decision-makers need to know more than just energy quantities and prices over time, the committee concluded. The National Energy Modeling System should be designed to provide outputs on the economic, environmental, and national security implications of alternative energy policies, with priority given first to the mid-term time horizon and then to the longer term.

The behavior of energy users and suppliers must also be reflected in such a system, and elements of uncertainty need to be explicitly quantified. A modular design is recommended. Such an approach would simplify refinements, because each module could be readily replaced. Moreover, simple reduced-form models of the system would facilitate analyses within a matter of hours—instead of days or weeks. Specific design recommendations include:

- The NEMS should be designed to be modular in structure, so to be flexible in its use and to readily accommodate the substitution of alternative models (modules) in the system.
- A single model should not be used for short-term, medium-term, and long-term analysis. Similarly,
the DOE should not select the model to be used for medium-term analysis based on the desire to conduct long-run analysis through the same framework.

- The EIA should attempt to acquire an existing interindustry growth model and should not attempt to develop one itself.

- Development of the NEMS can rely extensively on existing models. However, several new models should be developed or acquired from external sources: beyond the interindustry economic growth model, these should include an environmental impacts model and a renewable energy supply and conversion model. Demand models need to be modified to enable a broader range of policy analysis than is possible with the current EIA models.

- A reduced-form version of each module should be developed and integrated into the NEMS. Such versions should approximate the response surface of the full modules. For typical policy analyses, the full module would be used for the sector examined and reduced-form versions would be used for other sectors. Reduced-form versions could also be used in uncertainty analyses, tests of the integrated set of modules, and quick-turnaround policy analyses.

- The NEMS should be configured to run on personal computers or work stations, unless such hardware constraints would entail significant loss of the capabilities envisioned for NEMS.

- One or more EIA analysts should be charged with the general knowledge of all modules, even those not developed at EIA.

- In developing the environmental module, initial efforts should be focused on quantifying direct and indirect air emissions. If resources are not sufficient for this task, then EIA should focus attention first on the greenhouse gas emissions associated with the extraction, production, transportation, and use of energy.

- The NEMS should capture the effects on behavior of changing information, particularly information changing as a result of contemplated policy actions. Model users should be able to include alternative assumptions about the formation of expectations, including those defined theoretically as myopic, adaptive, and rational expectations.

- The NEMS should provide carefully envisioned graphics and report writers to provide routine graphical and numerical output of the types normally found helpful for analytical purposes.

The study concludes that a major effort is needed to collect more extensive data and information on the United States energy system, especially on end use. In such an effort, DOE and EIA should consider the following points:

- Essential to bottom-up demand modeling is knowledge of underlying activities: housing, commercial buildings, industrial production, and transportation. To obtain such information, EIA needs to improve its link to other data-gathering entities.

- Where behavioral information is inadequate, EIA or other DOE offices should help generate interest in obtaining it, by soliciting research, holding workshops, or stimulating other agencies to sponsor research. EIA should devote some resources to sponsoring research in this area.

Over the next 30 years, the United States will likely spend several trillion dollars to satisfy increasing demands for energy services. If a better modeling system could guide energy investments in a way that addresses environmental and national security concerns while reducing costs by only 1 percent, the committee noted, "it will pay for itself a thousand-fold." Thus, the committee concluded, a National Energy Modeling System is critical to policy decisions that have effects extending over the next 25 years and beyond.

####
CONSOLIDATED NATURAL GAS TO LICENSE HYDROCARBON SEPARATION TECHNOLOGY

Consolidated Natural Gas Company (CNG) in Pittsburgh, Pennsylvania, has decided to license its patented technology for a more efficient way to separate the hydrocarbon component from coal, oil shale, tar sands, and other hydrocarbon bearing materials.

The process, called explosive shattering, uses a supercritical fluid to selectively reduce the hydrocarbon component to micron-sized particles for more efficient use in coal gasification, liquefaction, and other fuel and chemical processing operations.

CNG originally developed the technology as part of a coal gasification project. Research documenting the operating parameters of the technology was conducted at the IIT Research Institute and CNG, and supported in part by the United States Department of Energy's Pittsburgh Energy Technology Center.

Explosive shattering saturates the porous hydrocarbon components of raw feedstocks with supercritical fluid, then explodes the hydrocarbon into micron-sized particles when the pressure is released. Nonporous mineral components are unaffected by the expansion and can be more easily separated from the hydrocarbon material, yielding a hydrocarbon product that is both cleaner and significantly more reactive. For example, CNG’s research has shown that explosively shattered bituminous coal has a lower peak oxidation temperature, comparable to that of subbituminous coal, while maintaining the higher heating value of bituminous coal. Research has also shown that explosively shattered coal exhibits a significant increase in solubility in various solvents.

CNG believes it owns all the significant process and apparatus patents on this technology in the United States and other countries. The company, therefore, can offer a complete package to interested licensees in virtually all industrialized countries.

Near Term Progress

According to Mills, several new or improved catalytic processes to produce fuel from syngas are either in operation or are in an advanced stage of development. Mobil Oil’s methanol-to-gasoline (MTG) process has been in operation in New Zealand for 6 years, supplying about one-third of that country’s gasoline.

Improvements in the MTG process have been made since its New Zealand installation in fixed-bed form. The TIGAS variation, developed by Topsoe, provides for plant savings through process integration. Alternatively, a fluid bed catalytic version of MTG, having improved economics, has been demonstrated on a semicommercial scale.

The slurry FT + ZSM 5 concept consists of slurry phase FT followed by upgrading of the products over a ZSM 5 catalyst. Either of two modes of operation, a low wax and a high wax mode, produced excellent yields of high quality fuels.

Shell Oil Company is pioneering the concept of carrying out syngas hydrogenation using a catalyst, possibly based on cobalt rather than iron, under conditions that result in a high degree of polymerization. Modern technology provides that the wax product can be efficiently hydrocracked to produce a kerosene and high quality diesel fuel. It is estimated that the energy efficiency of gas to product is 60 percent. A large plant in Malaysia is scheduled to come onstream in 1993.

Fuel Resources Development Company, a subsidiary of Public Service Company of Colorado, has built a small plant near Denver in which landfill methane is converted to syngas and then to hydrocarbon fuels using the slurry catalyst technique pioneered by Koelbel in Germany. Tests by Detroit Diesel Corporation showed an excellent diesel fuel can be made which on combustion showed a surprisingly favorable particulate reduction.

A pilot plant trial of slurry FT is planned in 1992 at the Air Products pilot plant at La Porte, Texas, inspired by projected improved economics.

Near-Term Progress

According to Mills, the extensive growth in methyl tertiary butyl ether (MTBE) has now resulted in an impending shortage in isobutylene, generally obtained as a byproduct from catalytic cracking. This has inspired research searching for cracking catalysts which produce larger amounts of suitable olefins. It is of considerable interest that isobutylene can be manufactured from syngas. This involves first production of isobutanol (IBA), which is catalytically dehydrated.
The technology for hydrogenation of CO to mixed alcohols has been developed extensively. It has been noted that in the Lurgi process 60 percent of the C$_4$ alcohols is isobutanol. One research report claims 59 percent isobutanol from syngas using an optimized catalyst. It can be noted that mixed alcohols containing C$_4$, C$_2$, C$_3$ is not now well regarded. MTBE is considered to be much more fungible. One important technological feature, says Mills, is the ability to recycle lower alcohols to produce higher alcohols. There is some evidence that C$_2$ and C$_3$ alcohols are so converted, but MeOH is converted back to syngas. However, even if the methanol is converted to syngas, this ultimately is transformed into higher alcohols. This is a distinct advantage over similar hydrocarbon synthesis where methane which is formed does not revert to syngas, but must go to a separate and costly reforming step.

A further consideration of IBA as a fuel is its potential as a competitor of MTBE. IBA has a good octane rating and lower vapor pressure (Table 1). IBA is highly hydrocarbon-soluble and so does not suffer the disadvantages of lower alcohols with respect to phase separation in the presence of water. It also should be mentioned that there are a number of other oxygenates which have potential markets. These include not only other ethers such as TAME (tertiary amyl methyl ether), DME (dimethyl ether), diisopropyl ether, but also dimethyl carbonate and other oxygenates, says Mills.

More economical synthesis of methanol has been developed by extensive research and pilot plant testing using a slurry catalyst system at Air Products' pilot plant at La Porte. Major improvements in throughput have been achieved by techniques such as more efficient gas distribution configurations. Decreased investment costs have been made possible by demonstration of simpler heat exchange equipment. Also a big step forward was catalyst systems which could catalyze shift as well as synthesis, thus providing the means to directly use low H$_2$/CO ratio gas from modern gasifiers. Recently it has been demonstrated that by coproduction of MeOH and DME, much higher CO conversion per pass is achieved.

Mills also noted that the Eastman plant, which manufactures acetic anhydride from syngas produced from coal, also produces and markets methanol. He cites as evidence of the economic viability that this plant has been expanded recently.

### Mid/Longer Term

A wide variety of novel syngas conversion catalysts have been investigated, testing novel concepts, particularly for synthesis of oxygenates.

Dual function catalysts have been found to activate CO by Rh and hydrogen by MoO$_3$ sites not inhibited by CO. The enhanced kinetics then provides highly active catalysts and point the direction for future design of even more active catalysts for selective production of alcohols at low temperature. There is also new interest in systems involving CO activation using base catalysts such as KOCH$_3$. New interest has been sparked by the report that there is a tolerance for low levels of H$_2$O and CO$_2$ by simultaneous use of both catalysts.

### Economics

Because of thermodynamic limitations, the energy efficiency of indirect liquefaction is lower than for direct liquefaction of coal. However, the cost of a synthetic fuel is much more dependent on plant investment costs than on raw materials costs. A further consideration of synfuel economics is the value placed on their environmental performance qualities.

Mills says the most striking economic news is the estimates which have been made for the production of diesel and gasoline from syngas using modern gasifiers coupled with slurry FT. The resulting increase in energy efficiency and decrease in selling price is shown in Table 2. The $42 per barrel price for gasoline/diesel by slurry FT is as low or lower than direct liquefaction for the same products (not crude oil) made by direct liquefaction of coal.

### Table 1

<table>
<thead>
<tr>
<th></th>
<th>Blending RVP</th>
<th>Blending Octane</th>
<th>BTU/Gal. 1,000's</th>
<th>Prod. MMGPD</th>
</tr>
</thead>
<tbody>
<tr>
<td>MTBE</td>
<td>8</td>
<td>110</td>
<td>109</td>
<td>6.1</td>
</tr>
<tr>
<td>ETBE</td>
<td>4</td>
<td>110</td>
<td>117</td>
<td></td>
</tr>
<tr>
<td>TAME</td>
<td>2</td>
<td>103</td>
<td>112</td>
<td></td>
</tr>
<tr>
<td>t-Butanol</td>
<td>9</td>
<td>100</td>
<td>101</td>
<td></td>
</tr>
<tr>
<td>Isobutanol</td>
<td>5</td>
<td>102</td>
<td>95</td>
<td></td>
</tr>
<tr>
<td>Gasoline</td>
<td>87</td>
<td>125</td>
<td>300</td>
<td></td>
</tr>
</tbody>
</table>
### TABLE 2

**IMPROVEMENTS IN INDIRECT LIQUEFACTION OF COAL**

<table>
<thead>
<tr>
<th>Plant Output, BPSD</th>
<th>Lurgi + Arge FT</th>
<th>Shell + Arge FT</th>
<th>Shell + Slurry FT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alcohols</td>
<td>1,762</td>
<td>1,836</td>
<td>1,954</td>
</tr>
<tr>
<td>Propane</td>
<td>4,467</td>
<td>4,037</td>
<td>4,207</td>
</tr>
<tr>
<td>Butane</td>
<td>5,403</td>
<td>5,522</td>
<td>5,560</td>
</tr>
<tr>
<td>Gasoline</td>
<td>36,450</td>
<td>32,494</td>
<td>33,953</td>
</tr>
<tr>
<td>Diesel</td>
<td>35,419</td>
<td>39,617</td>
<td>37,828</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>83,501</strong></td>
<td><strong>83,505</strong></td>
<td><strong>85,503</strong></td>
</tr>
<tr>
<td>Energy Efficiency, %</td>
<td>48</td>
<td>53</td>
<td>59</td>
</tr>
<tr>
<td>Required Selling Price, $/Bbl</td>
<td>55</td>
<td>48</td>
<td>42</td>
</tr>
</tbody>
</table>

Mills also noted the costs of subsidization for the gasohol program in the United States. The federal tax benefit is $0.60 per gallon of alcohol used in gasohol. In 1987 there were 55,400 barrels per day of ethanol fuel sales corresponding to a subsidy of about $500 million annually. There is an additional subsidy in the corn used to produce the ethanol.

###
"High-Pressure Hot Separator," Heinz Frohnert, Edgar Muschelknautz, Klaus Niemann, Werner Riedel - Inventors, Veba Oel Technologie GmbH DE, United States Patent Number 5,084,079, January 28, 1992. A high-pressure hot separator for the separation of an overhead product from a process of high-pressure hydrogenation of coals, tars, crude oils, whose distillation and extraction products or similar carbon-containing feedstock such as heavy oils, low temperature carbonization oils, extracts of heavy oil sands and the like, is downstream from the bottom phase reactors of the high-pressure hydrogenation. The separator is constructed from a vertically erected cylindrical pressure jacket having an upper cover, a lower cover, an inside adjacent thermal insulation member and a cylindrical wall insert. The overhead product is separated into a gas/vapor phase and a bottom product. A cyclone separator is installed in the gas/vapor space of the hot separator for improvement of the separation function.

"Combustion Engine," Satnarine Singh - Inventor, United States Patent Number 5,074,110, December 24, 1991. A combustion engine comprising of a piston and cylinder assembly wherein the cylinder receives hot gasses emitted from a combustion chamber, the hot gasses being generated from the combustion of any of a variety of combustible material included but not limited to wood, coal, dry vegetation, and sawdust. The hot gasses, once received in the cylinder, are subjected to a compression stroke during which water is injected therein to create steam from the compression of the hot gasses and injected water whereby the resulting energy of expansion of the steam within a greatly reduced volume will result in a power stroke of the piston causing efficient work to be delivered to a power takeoff structure such as a crank shaft or the like.
COMING EVENTS

1992

JUNE 1-4, COLOGNE, GERMANY – 37th International Gas Turbine and Aeroengine Congress and Exhibition

JUNE 7-10, CALGARY, ALBERTA, CANADA – Petroleum Society of CIM 43rd Annual Technical Meeting

JUNE 7-12, FLORENCE, ITALY – Florence World Energy

JUNE 11-12, CALGARY, ALBERTA, CANADA – AOSTRA and Canadian Heavy Oil Association 1992 Conference


JUNE 17-20, COLORADO SPRINGS, COLORADO – National Coal Association Annual Convention

JUNE 22-26, ESSEN, GERMANY – International Conference on Carbon: Carbon ’92

JULY 14-15, MORGANTOWN, WEST VIRGINIA – Fuel Cells Contractors Review Meeting

AUGUST 3-7, SAN DIEGO, CALIFORNIA – 27th Intersociety Energy Conversion Engineering Conference

AUGUST 4-7, WINTER PARK, COLORADO – Confab ’92, A Fossil Fuel Meeting

AUGUST 9-12, MINNEAPOLIS, MINNESOTA – American Institute of Chemical Engineers Summer Meeting

AUGUST 23-28, WASHINGTON, D.C. – American Chemical Society National Meeting, Division of Fuel Chemistry

AUGUST 31-SEPTEMBER 4, BISMARCK, NORTH DAKOTA – Symposium on Opportunities in the Synfuels Industry


SEPTEMBER 4-5, EDMONTON, ALBERTA, CANADA – Hydrocarbon Residues and Wastes Conversion and Utilization

SEPTEMBER 15-17, MORGANTOWN, WEST VIRGINIA – Gasification Contractors Review Meeting

SEPTEMBER 15-17, MAASTRICHT, THE NETHERLANDS – Coal and Power Technology Exhibition ’92


SEPTEMBER 22-24, CLEVELAND, OHIO – First Annual Clean Coal Technology Conference

SEPTEMBER 28-30, LONDON, UNITED KINGDOM – Second International Cokemaking Congress

OCTOBER 12-16, ROME, ITALY – Second International Congress on Energy, Environment and Technological Innovation

OCTOBER 12-16, LENINGRAD, USSR – International Symposium on Unconventional Hydrocarbon Sources

OCTOBER 18-21, CHICAGO, ILLINOIS – American Gas Conference

OCTOBER 18-22, ATLANTA, GEORGIA – Joint Power Generation Conference

OCTOBER 21-23, SAN FRANCISCO, CALIFORNIA – EPRI Conference on Coal Gasification Power Plants

OCTOBER 27-28, MORGANTOWN, WEST VIRGINIA – Heat Engines Contractors Review Meeting

SYNTHETIC FUELS REPORT, JUNE 1992

1-17
NOVEMBER 1-6, MIAMI BEACH, FLORIDA – American Institute of Chemical Engineers Annual Meeting

NOVEMBER 8-10, NEW YORK, NEW YORK – Annual Meeting of the American Petroleum Institute


NOVEMBER 17-19, ORLANDO, FLORIDA – Power-Gen '92

NOVEMBER 18-20, LEXINGTON, KENTUCKY – Eastern Oil Shale Symposium
PROJECT ACTIVITIES

PETROSIX COMMERCIAL MODULE APPROACHING 4,000 BARRELS PER DAY

Petrobras, the Brazilian state oil company, has been commercially producing shale oil in its new retort module since December 15 in Sao Mateus do Sul, State of Parana. The project has been under development since 1954, and has required US$500 million in investments including research and development for the Petrosix shale oil recovery process. The shale oil cost for a plant designed to produce 25,000 barrels per day would be between $20 and $22 per barrel, according to Petrobras. The company says it is confident that future shale oil prices will be competitive with oil.

The Sao Mateus do Sul project is currently producing at 70 percent of the full-scale capacity. Total daily production is expected to reach 4,000 barrels of shale oil, 140 metric tons of fuel gas, 50 tons of liquefied petroleum gas and 100 tons of sulfur.

The Petrosix process was developed and patented by Petrobras. Contracts are being explored for its use in the United States and Estonia. Requests for information have also arrived from Canada, Australia, China, Israel and Morocco, according to Petrobras.

The Brazilian shale reserves (oil equivalent) are estimated at 50 billion barrels in the Irati Formation.

CONVERSION OF UNOCAL UPGRAIDER TO METHANOL PLANT PROPOSED

Colorado Clean Fuels Company has obtained approval from the Garfield County (Colorado) Commissioners to refit Unocal Corporation's Parachute shale oil upgrading plant for fuel processing. The plant will process natural gas into four products: methanol, smokeless diesel, naphtha and wax.

The county commissioners approved the request after a public hearing on the matter. Area residents were primarily concerned with maintaining the valley's clean air. The permit was granted with the stipulation that the environmental and other promises made by Colorado Clean Fuels in its application be kept.

The anticipated project development calls for July 1992 construction, employing 40 to 110 workers, followed by operation startup employing 24 people. If the company obtains state and federal permits as well, the plant will be operational in August 1993.

The company plans to produce 4,200 barrels of methanol per day from natural gas. The natural gas will be obtained from the Parachute area. In addition, 138 barrels per day of diesel fuel, 51 barrels per day naphtha, and 1,111 barrels per day of wax will be produced.

JOINT DEVELOPMENT OF OIL SHALE AND COAL PROPOSED IN SOUTH AUSTRALIA

The Leigh Creek oil shale deposits offer the potential to add significantly to the oil production of South Australia and have a distinct advantage over other deposits in that they are currently being mined. This improves their economic potential and the opportunity for early development. J.F. Harrison, et al., of Central Australian Oil Shale Pty. Ltd., discussed their findings on the Leigh Creek deposits at the Sixth Australian Workshop on Oil Shale.

The Leigh Creek deposits are to be utilized to supply oil shale to an onsite processing plant for the extraction of oil and related petroleum products for marketing in South Australia and elsewhere. The Leigh Creek oil shale deposits are located in the overburden overlying the Main Series coal measures in the Leigh Creek coalfields located 550 kilometers north of Adelaide.

The deposit is considered to be a typical oil shale suitable for the supply of shale to a crushing and processing plant and sufficient reserves have been delineated to provide a 20-year supply. Additional sources of oil shale exist beyond the current mining limits and may be used to supply shale requirements for the remainder of the processing plant life. This could also increase the economic reserves of coal available for use by the Electricity Trust of South Australia (ETSA) in power generation as it reduces the cost of overburden removal. Average oil shale production from the mine is estimated to be 10 million tons per year which would produce approximately 3 million barrels of oil annually.

The oil shale is currently being mined as overburden as part of the operation to mine coal for ETSA's Port Augusta power stations. The mine currently operates three shifts per day, 7 days per week, and the oil shale will be stockpiled at the processing plant which will also operate on a three shift, 7 day per week basis and draw its feed from the stockpile. This reduces the problem of interfacing scheduling of the mine with the processing plant.

According to Harrison, the current mining method will present difficulties with scheduling production of oil shale.
because the reserves would be excavated as blocks, not continuously. However, it is proposed to introduce terrace mining for overburden removal, and this mining method, in conjunction with an auxiliary operation, would ensure a continuous supply of shale to the processing plant.

There has been extensive geotechnical work carried out by ETSA to determine the most economic mining method for coal extraction and no geotechnical or groundwater constraints are expected in the mining of the Main Series shale. The processing plant will be located on the northern margins of the deposit to minimize transport costs of the shale. It is assumed that the oil shale retort will be an AOSTRA-Taciuk type as proposed for the Stuart Oil Shale Project, although microwave technology is being investigated.

The processed shale will either be returned to the mine and dumped with the other overburden where it will become an integral part of the overburden dump, or it will be placed in a separate dump adjacent to the processing plant. Either of these methods will be environmentally beneficial as it will reduce the potential for fires in the dumps.

Oil Shale Reserves

The shale resource has been estimated at approximately 2,000 million tonnes. Mining reserves have been estimated at a minimum of 200 million tonnes from information on the length of strike of the deposit, thickness of the band of oil shale, and the proposed mining depth (200 meters). The reserves were calculated by assuming a 30 to 130 meter thick band of high grade oil shale running the length of the main series. Reserve definition for quality and mine scheduling purposes will be confirmed by further drilling and testing prior to project commitment.

The selection of the mining sequence is based upon the overburden stripping planned to ensure adequate coal supply to the Northern Power Stations. The oil shale operation will be integrated into the existing overburden removal program to satisfy the requirements of both operations. The mining sequence will commence at the eastern end of the deposit when terrace mining is introduced. However, this is in the poorer quality oil shale and a supplementary operation may have to take place at the northern end of the deposit to ensure security of supply to the processing plant.

For the purposes of the initial studies, it is proposed to haul shale directly to the processing plant using the overburden trucks. In later studies a detailed analysis will be undertaken to optimize the haulage method. The relatively low output of the plant and the need to dispose of shale ash make the use of conveyers unlikely.

Processing Plant Requirements

The processing plant requirements for oil shale are based upon a demonstration plant being constructed initially and then developing through to a full scale commercial plant.

The requirements are as follows:

- During the first 2 years of operation the processing plant only requires 10,000 tons of shale per day.
- The maximum demand occurs in the fourth year when 33,000 tons per day are required.

The total processing plant requirement is approximately 200 million tons of shale over the 20-year project life which is approximately 30 to 40 percent of the total overburden. Thus, there will be sufficient shale to continue the project beyond 20 years. It is proposed to initially construct a semi-commercial plant to process 10,000 tonnes per day of oil shale producing 3,000 barrels per day of oil products. When the processing technology has been proven, the plant will be expanded to produce 10,000 barrels per day of oil products. Any further expansion beyond this size will be dependent on reserves and market requirements.

Testing shows the shale oil has potential for producing middle distillates, kerosene, and diesel fuel.

Mining Criteria

The present mining method would mean that the high grade band of oil shale was mined spasmodically. There would be no oil shale mined at first as blocks of overburden were mined successively until the benches with the oil shale were reached. All of the oil shale in that block would then be mined and stockpiled ready for use in the processing plant.

The mining equipment will be owned and operated by ETSA so the only consideration for the oil shale operation is the method of transportation of shale to the processing plant.

SPP SUFFERS SETBACK ON STUART PROJECT

In its quarterly report for the period ending March 31, 1992, Southern Pacific Petroleum (SPP) reported on the status of the Stuart Shale Oil Project. SPP and Central Pacific Minerals (CPM) have been engaged for the last 7 years in planning the construction of a major shale oil plant at the
Stuart deposit near Gladstone, Queensland, Australia. This has involved the drilling of an unusually high grade body of oil shale (the Kerosene Creek Formation), testing, evaluation and adoption of Canadian processing technology (AOSTRA-Taciuk Processor) and the subsequent planning of a three-stage development to produce a total of approximately 84,000 barrels of syncrude and oil products per day.

Stage 1 of this development is a technology demonstration phase. Stages 2 and 3 represent 96 percent of the planned production and over 90 percent of its cost. These stages are designed to operate with full commercial-sized equipment and are expected to generate a commercial rate of return at current oil prices, thus enabling normal financing without government assistance.

The AOSTRA-Taciuk retorting technology, however, has not yet been demonstrated on a scale larger than an 80 tonne per day pilot plant. Engineering and economic prudence therefore dictates the construction of an introductory stage whose principal objective is to demonstrate the technology at a 6,000 tonne per day intermediate scale before embarking upon the full expansion (Stages 2 and 3).

The demonstration stage (Stage 1) does not benefit from economies of scale available in full commercial production. The resulting lower margins make it more difficult to finance this demonstration stage. To surmount this factor, in part, the companies have relied upon excise regulations which have been in place since 1948. These regulations allow an excise exemption for gasoline produced from shale oil.

The companies approached the Australian Government to seek assurance of the continuity of these long standing regulations to facilitate the financing of the demonstration stage. As a result, the federal government announced a decision (June 7, 1991) that Stuart Stage 1 would be designated an Approved Shale Oil Demonstration Plant which would continue to benefit from the excise arrangements until 2005.

In practice, under these arrangements, the price of gasoline at the pump (including excise) remains unchanged. The excise component is foregone by the government during this temporary period and is returned to the project as revenue.

SPP/CPM say this support provided enough assurance of continuity of the regulations to permit the companies to seek Stage 1 financing on that basis. No such assurance was sought or is considered necessary for the expanded commercial operations of Stages 2 and 3.

Subsequently, the federal opposition party in Australia announced policies it proposes to initiate if elected to government. Part of the overall measures proposed by the opposition includes the abolition of all excise taxes on gasoline.

The companies have had discussions with the opposition party to ensure that the value of the existing arrangements to the demonstration phase of the project will be preserved in one form or another. However, the companies have now been advised of a Shadow Cabinet decision to the effect that it is unwilling to provide such an assurance.

Consequently, the companies are now in discussion with their contractors, banking advisors and potential co-venturers to assess appropriate adjustments to the presently planned approach.

The international engineering group involved in the full evaluation of the Stuart development is Bechtel Corporation of San Francisco, California. They are actively involved in assessing appropriate adjustments to the presently planned approach.

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CONOCO DONATES OIL SHALE RECORDS TO COLORADO SCHOOL OF MINES

Conoco will donate an anthology of oil shale records to the Tell Ertl Oil Shale Repository, which is housed in the Arthur Lakes Library at Colorado School of Mines.

"Much development has been carried out over the past several decades to demonstrate recovery technology," said D. Wilson, vice president of research and engineering for Conoco in Ponca City, Oklahoma. "This technology should not be lost to future generations," he continued. "Incorporation of Conoco's technical records in the Tell Ertl Oil Shale Repository will insure their preservation."

The Conoco gift is the fourteenth collection to be donated to the Tell Ertl Repository. The collection now consists of more than 300 archive boxes, containing over 55,000 documents and filling over 500 feet of shelf space.

NORTH AMERICAN CHEMICAL BUYS INTEREST IN NATEC

NaTec Resources, Inc. has reached an agreement for North American Chemical Company to purchase a 50 percent interest in a newly created subsidiary of NaTec Resources. This new company will own all of NaTec's nahcolite production operations, including the production facilities in western Colorado.

Under the terms of the agreement, NaTec Resources will receive $10 million in cash payable over 4 years without interest. The price is subject to adjustment based on ultimate performance levels of the plant. The joint venture's production operations will continue to supply sodium bicarbonate to NaTec and to North American Chemical. As an active participant in the venture, North American Chemical will supervise the operation of the production facilities.

The agreement is subject to the approval of the boards of directors of both companies, leaders of North American Chemical and certain conditions including the achievement of performance levels at the plant and completion of due diligence by North American Chemical. The pollution control operations of NaTec Resources will remain wholly owned by NaTec Resources, Inc. and will not be affected by the North American Chemical transaction.

S. Christopher, chairman of NaTec, said, "North American Chemical's substantial operating experience and expertise in similar production operations is expected to result in lower production costs and greater productivity as well as a reduction of capital requirements for existing operations and expected future expansion. In addition, the added volume that North American Chemical immediately brings to the joint venture will result in lower operating costs in the near term."

NaTec's Colorado facility came online in 1991. Phase I design capacity is 125,000 tons per year. Proven reserves are approximately 85 million tons of high purity nahcolite, a naturally occurring sodium bicarbonate, located on 8,200 acres.

North American Chemical Company currently produces soda ash, boron chemicals and sodium sulfate for a variety of applications throughout the world.

NaTec Year-End Results

NaTec Resources has reported operating results for the year ended December 31, 1991.

A net loss of $7.0 million was reported on revenues of $2.1 million compared with a net loss of $4.8 million on revenues of $2.9 million for the previous year. The increase in the net loss, according to NaTec, is primarily attributable to preferred stock dividends, the excess of startup production costs over inventoried costs, and an increase in interest expense. The nahcolite facility was under construction in 1990 and completed in the first quarter of 1991.
COLD FLOW MODEL OF CIRCULATING FLUID BED RETORT TESTED

A cold flow model of a twinned, dense-phase circulating fluidized-bed system has been built and investigated for use as a continuous oil shale retort. The twin beds enable continuous circulation of the shale and ash, which act as the heat carrier, while keeping the combustion gas and the retort product gases separated (Figure 1). Y. He, et al., of the University of Queensland, Brisbane, Australia presented the study at the Sixth Australian Workshop on Oil Shale held in Australia in December.

The authors designed a fluidized-bed system with two adjacent compartments communicating through V-valves so that there is an abundant and easily controlled solid circulation between the compartments of the system while still keeping the gas flows substantially separated (Figure 2). There is always some gas crossflow between the two main compartments while solids exchange occurs. However, this gas leakage is well within tolerable limits. The authors found that, within the range of the experiments, the influences of gas rates to V-valves and risers are substantially identical.

For the study, the authors configured a fluidized bed divided into two compartments by a vertical baffle with V-valves located in the baffle to pump solids between the compartments. A V-valve is a kind of non-mechanical valve which controls solids flow rate through it by manipulation of the hydraulic gradients across it. Its major features are the wide range over which solids flow rate can be controlled and its good gas sealing ability.

Experimental

The fluidized bed, which is 300 millimeters square, is divided into two compartments by a vertical partition. V-valve/riser combinations pump material from one compartment into the other. During operation, bed material comprising a dense-phase gas-solid mixture flows from one compartment through a V-valve and riser to the other compartment. For cold model experiments, air was used as the fluidizing gas. The solid was silica sand.

The solids circulation rate, the gas crossflow rate and the system pressure drops were measured. Solid exchanging rates were determined by direct collection of the riser discharge over a short period of time and weighing. Measurement of gas crossflow was made by injecting the CO₂ tracer gas into the area of interest and then measuring its concentration in the other parts of the system.
Experiments were performed only under steady state. The bed height in the main compartment did not change during an experimental run. Gas rates to the main compartments, V-valves and risers were manipulated separately and independently.

Results

The authors set two system requirements, namely that a high and controlled solids circulation rate be achieved and that gas crossflow be minimized. The circulation rate sets the solids throughput and consequently governs the processing rate. The crossflow rate governs the product quality.

Solids Circulation: Results show that changing gas flow rates to the V-valves and risers have a substantially identical influence on solids circulation rates.

The solids circulation rate is sensitive to changes to both V-valve and riser gas rates. Similarly, increasing the gas rates to the main compartments also increases the solids rate, but not as dramatically as changing the V-valve or riser gas flow.

The circulation rate can be controlled by manipulation of the V-valve and riser gas rates, independently of the fluidization conditions in the main beds. Furthermore, the conditions in the two main compartments can be set independently of each other.

The circulation rate could be easily manipulated and circulation rates substantially in excess of those actually required by the process were easily reached. At the highest solids circulation rates, the entire solids inventory of a compartment can be turned over in much less than a minute.

Gas Crossflow: This is the proportion of gas which leaves the reactor in a stream other than the intended stream. Gas crossflow can occur by two main mechanisms, namely by being dragged with the solids as interstitial gas as it circulates around the system, or as a result of pressure induced flow. However, the results show the gas will always flow up the riser. On the other hand some gas does flow from the main compartment through the V-valve and this constitutes the crossflow.

Results of both solids circulation rates and gas crossflow demonstrate that gas injection to the V-valves and risers have substantially identical effects. The authors found that the V-valve/riser combination can be treated as one component in the system, which represents a significant simplification.

Under even the worst crossflow conditions, crossflow was found to account for less than 7 percent of gas leaving a main compartment. This is quite acceptable for oil shale processing, say the authors. They conclude that the process seems suitable for oil shale retorting, with maximum solids circulation rates well in excess of process requirements being easily achievable.

FINE GRINDING NOT NECESSARY FOR SHORT-CONTACT-TIME RETORT

B. So and P. Train of Amoco Research Center in Naperville, Illinois presented the effects of retort process variables on the product yields in a short-contact-time (SCT) retort at the 25th Oil Shale Symposium held in April at the Colorado School of Mines in Golden, Colorado.

Tract C-a oil shales were studied to find ways to increase oil yield and reduce retort costs. The richer shales formed oil with greater selectivity in the SCT-type retort (basically a modified fluid catalytic cracker). This favors mining of high-grade shale and beneficiating of lower grade shale. Although the time for shale heat-up from ambient temperature increased with particle size, the less than 6 seconds heat-up time obtained for all particles means that grinding the oil shale to smaller than 0.635 centimeters top size is not justified. Thus, grinding costs can be reduced. Amoco says its lumped kinetics model more accurately represents product yields within the database using four parameters than the existing six-parameter models. Comparisons with literature data showed good extrapolation to other reaction temperatures.

According to the authors, the success of this study was a direct result of pilot plant modifications that provided superior data acquisition capability. Moreover, the modifications allowed separate determination of oil and gas evolution rates and yields during retorting for the first time.

This leads to a new understanding of the reaction pathways involved. The maximum measured oil yield reached 120 percent of Fischer Assay with long residence time. Oil always represented more than 80 percent of the instantaneous hydrocarbon production.

Background

In thermal retorting, the kerogen is decomposed to form shale oil, coke, and gases which include light hydrocarbons. Another source of light hydrocarbon production is from the thermal cracking of shale oil. To investigate the intrinsic kinetics of oil shale retorting, it is desirable to obtain a high heat-up rate of the oil shale, to operate at constant temperature, and to minimize the vapor-phase residence time so oil cracking is minimal. These considerations led to the use of a batch fluidized-bed reactor to study the retorting kinetics of oil shale.

SYNTHETIC FUELS REPORT, JUNE 1992
Such kinetic data are particularly useful for simulating the operation of the SCT-type retort. A schematic diagram of the Amoco patented fluid-bed retort is shown in Figure 1. The retort section consists of a fast heating riser section and a long-residence-time stripping section.

Results

The results obtained impact future retort design and process operation in several ways. The authors feel, because richer shales have been shown to produce oil with greater selectivity through the decomposition of bitumen, mining of rich shale or beneficiating of lower grade shale would be particularly attractive.

The bitumen decomposition route is most sensitive to process conditions. The results indicate that enhanced oil yields result from the effect of richer shales on oil selectivity. The experimental results did not show that particle size affects yields. In an SCT-type retort the oil evolved in the injector and riser forms primarily from the decomposition of kerogen. The stripper would then be the retorting zone in which most of the bitumen reacts to products. Therefore, modifying conditions in an SCT stripper may have the most impact on retort yields.

The time required to fully heat the shale feed from ambient temperature was short in all cases and ranged from 1 to 6 seconds.

The ultimate yields of oil and coke were influenced by shale grade only. The yields of gas did not correlate with any of the process variables studied. Thus, high-grade shale looks well suited for a plant having an SCT-type retort. The Amoco kinetic data agree reasonably well with information published in the open literature by Lawrence Livermore National Laboratories.

The data show that considerable simplification can be made in the retort model because (a) oil and gas appear to form in the same lumped reaction steps; (b) the selectivity to oil and gas in these steps remains constant with time, temperature, grade, and particle size; (c) both kerogen and bitumen decomposition can be modeled using two regressed parameters each, resulting in a model requiring only four estimated parameters.

**FIGURE 1**

**SHORT-CONTACT-TIME TYPE OIL SHALE RETORT**

![Diagram of short-contact-time type oil shale retort](source: SO AND TRAIN)

SYNTHETIC FUELS REPORT, JUNE 1992

2-7
According to the authors, the model developed will be better able to predict the evolution of hydrocarbon products from an SCT-type retort.

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ADVANCED INTEGRATED OIL SHALE PROCESSING SYSTEM PROPOSED

"A State-of-the-Art Integrated Process for Oil from Colorado Shales" is the title of a paper presented by J.E. Gwyn at the 25th Oil Shale Symposium in Golden, Colorado in April. Gwyn discussed an integrated process with 100,000 barrels per day of syncrude capacity as the basic building block of an oil shale industry in Western Colorado. Key components include longwall mining/backfilling (Figure 1) and hydroretorting of the shale. These are integrated with: pulverizing, pressurizing, and preheating of the raw shale; cooling, depressurizing, conditioning, and compaction of the spent shale; topping and bottoming of the syncrude for feed to hydrogen and utilities production, respectively; and pipeline transport of the stable heart cut to remote refining areas. These components use proven state-of-the-art unit operations technologies.

Requirements of the Surface Processing

Gwyn says that in order for an oil shale industry to approach or achieve self sufficiency, the process technologies must achieve the following:

- Reduce the requirement for the limited human and natural resources of the area
- Maximize the recovery of the in-place oil
- Produce a premium crude without the need for on-site upgrading
- Reduce capital and operating costs
- Raise the cap on potential production rates
- Minimize the environmental impact

![Figure 1](image-url)

**Figure 1**

**Shale Longwall Mining and Refilling and Compaction**

[Diagram of shale mining and compaction process]

*Source: Gwyn*

SYNTHETIC FUELS REPORT, JUNE 1992

28
The Proposed Process

In the proposed process, selected technologies have been integrated in a synergistic way to meet the above requirements. A key technology is fluidized bed retorting in the presence of hydrogen (hydroretorting). This can produce about 130 percent of Fischer Assay yield of an upgraded, stabilized syncrude. This syncrude can be piped to existing refineries without the extensive onsite upgrading required of other retorting processes. Another key process is the longwall, progressive mining/backfilling of the shale. Longwall mining allows the total shale resource to be recovered by layers. Backfilling prevents subsidence and other surface damage while providing for an innocuous disposal of the reconstituted spent shale. Other technologies such as gas/solids transport and fluidization allow these key technologies to be integrated to achieve the desired effect.

To integrate these key processes together the total process becomes:

- Longwall or other full resource mining of the raw shale
- Size reduction to minus 1.5 millimeters with minimum dusting
- Pressurizing the raw shale to the range of 100 to 300 psi
- Preheating of raw shale and cooling of spent shale
- Hydroretorting for high yield of a stabilized, light syncrude product
- Depressurizing of the spent shale for disposal
- Topping and bottoming of the syncrude product to provide a light hydrocarbon reformer feed (hydrogen plant) and fuel to the process utilities plant, respectively
- Hydrogen plant for hydroretorting
- Utilities plant for process energy requirements
- Compaction of spent shale and backfilling of mined walls for support of overburden and innocuous disposal of the spent shale
- Pipeline transport of syncrude to West Coast, Central States, and/or Gulf Coast for further processing to specification products

It is assumed that the first years of production will be based on the oil-rich Mahogany zone shale. This will provide a more rapid payback. It will also allow time for technology improvements for higher throughputs when lower grades of shale are processed.

Raw Shale Mining

Although the overall utilization of the resources would be improved by starting at the base level, say at 2,000 feet depth, the prospects for a viable venture dictate that the first mining start at the base of the Mahogany zone. The longwall mining approach (Figure 1) cuts along the advancing face of the mined tunnel and backfills with compressed and consolidated spent shale along the trailing face. The entire stratum of 10 feet is mined over the tract assigned to this plant before starting on the next higher stratum.

The mined shale is transported to the surface by conveyor belts for intermediate storage and subsequent pulverizing for processing.

Pressurizing the Pulverized Raw Shale

The shale must be pressurized to about 300 psi for hydroretorting. For the proposed process a series of eight pneumatic riser/standpipe stages is used. A single stage is illustrated in Figure 2. The particulate shale is transported to the top of the first standpipe where the transporting gas is separated for reuse. The shale flows into and down the standpipe in a dense fluidized state. The effective interface is at Hi. The shale then flows into a lift pot where it is maintained in a fluidized state by gas admitted near the base of the lift pot. As the shale rises above the lift nozzles it is entrained into and up the riser at a velocity to maintain an effective density of about 5 pounds per cubic foot. The shale is transported to the top of the next standpipe and so on through the eight stages of pressurization.

Hydroretorting Section

Hydroretorting of shale is not catalytic in the same sense as hydrotreating or hydrocracking in the refining of oil. Gwyn suggests that with Colorado shales, the dissociation of the kerogen/shale bonding releases reactive hydrocarbon radicals and oxygenates. The role of the hydrogen is to saturate these species and thereby prevent condensation and polymerization reactions that lead to pitch and asphaltene formation. The hydroretorted shale oil is a light liquid that is stable on standing.

The hydroretorting reactor is a tall vessel (7/1 H/D ratio) operating in a turbulent fluidization regime. Both gas and particulates flow upward so that entrainment of solids from the top is a part of the process. The flow is illustrated in Figure 3. The solids are introduced at the bottom in dense flow for the last pressurizing or heating stage. Hydrogen is introduced at about 4 times the hydrogen consumption rate (4/1 recycle ratio). A top barrier plate promotes solid reflux to maintain a high solids bed density within the reactor ves-
The hydrogen/product gases and spent shale solids leave through an annular path to give a flow velocity of about 30 feet per second. The hydrogen/product gases are separated from the spent shale in a cyclone/stripper vessel. Steam is the stripping gas to maximize product recovery.

Compaction and Backfilling of Spent Shale

The cooled, depressurized spent shale is first conditioned by rehydrating with 5 to 10 percent water. The water source is low pressure steam condensate and product steam water condensate. Also, the shale acts as an absorbent for contaminants so these water streams do not require additional treatment.

The conditioned shale is compressed to about 8,000 psi to reduce it back to its original, in-place volume. This might be done by pressing spent shale into bricks under mild pressures on the surface to facilitate conveying of the solids and hydraulically ramming these bricks into place to the desired volume in the mine tunnel.

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DAMPING FACTORS IMPROVE SIMULATION OF OIL SHALE BLASTS

D.S. Preece of Sandia National Laboratories, Albuquerque, New Mexico, presented his work on the effect of damping on computer simulation of rock motion at the 25th Oil Shale Symposium in April. Speaking in Golden, Colorado, Preece discussed how computer modeling of the blasting process can aid in gaining an understanding of the physics controlling the process. The sequence of events in a blast occur so
rapidly and in such a violent environment that measurements are still difficult to obtain. Computer modeling using a program such as Sandia's DMC can provide insights into the physics of the rapid and violent events associated with a blast. DMC has been used to simulate crater blasting and the blasting of oil shale for modified in situ retorting. The focus of Preece's paper is on the influence that damping has on the velocity distribution in the rock mass during the rock motion phase of a blast. Because velocity distribution is a controlling factor of muck pile shape, damping also contributes to muck pile shape.

Simulation studies show that damping factors must be chosen wisely because some values of damping factors can give unreasonable results. According to Preece, a need for two values of damping in a rock motion simulation has become apparent. The damping factor for intact rock, before significant movement, should be lower \((C_d < 0.5)\) than it is for loose rock where jagged edges and corners interact with significant energy absorption \((C_d > 0.8)\). DMC has been modified to allow for transition from lower to higher damping factors for each sphere as movement occurs. The low and high damping factors are both input by the user. The results of rock motion simulations have been shown to qualitatively match field data.

Observation of many bench blasts using high speed motion photography indicates that the velocity is highest at the face and decreases with depth in the burden as motion occurs. A measurable quantity that is dependent on the velocity distribution is the muck pile shape. Bench blast experiments demonstrated that the use of high damping factors during computer simulation usually result in excessive motion when the results are compared with field data.

A lower damping factor \((C_d < 0.5)\) appears to be necessary for the calculated rock motion to exhibit behavior that is similar to what is observed in an actual blast. However, when lower damping factors are used throughout the calculation, damping in the muck pile does not appear to be heavy enough. The material keeps moving longer than it should and sometimes the surface levels out, similar to a fluid. Preece proposes that a lower value of damping during the early part of the calculation can be justified by considering that the rock is fragmented but the joints are still interlocked. Because there has been very little movement, the surfaces on either side of the fractures are in full contact and damping of the transfer of momentum from one rock to the next is relatively small. Contrast this with what occurs after the rock has moved some distance and the surface to surface contact has been destroyed. In this case contact between individual particles means crushing of asperities as jagged mismatched surfaces interact. This type of interaction absorbs a large amount of kinetic energy from the system which can be modeled with a high damping factor \((C_d > 0.8)\). An approach currently used in DMC is to enter two values for the damping factor \(C_d\). The lower one represents the initial damping factor where rock surfaces are still in original contact and the other represents the damping factor between rocks that are not interlocked but where jagged surfaces are colliding and asperities are being crushed. The lower damping factor evolves into the upper damping factor linearly as each sphere moves. It is currently assumed that this transition occurs over 5 sphere diameters.

Figure 1 shows the spherical element model results with a lower damping factor set at 0.3 and the upper damping factor set at 1.0. Using the two damping factors results in initial motion that is more like that obtained with a \(C_d\) of 0.3. The higher damping factor of 1.0 for the material in the muck pile causes it to settle down faster and give a more realistic final profile than when a smaller \(C_d\) is used throughout, causing the muck pile to continue to move long after calculations with higher damping have stopped.

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**MICROWAVE RETORTING SHOWS ADVANTAGES FOR AUSTRALIAN OIL SHALE**

Research carried out at the Microwave Applications Research Center (MARC) of the University of Wollongong, New South Wales, Australia has shown that microwave-retorted shale from Australia's Kerosene Creek deposit produces oil which has advantages over conventionally retorted oil in terms of its composition. D.H. Bradhurst from MARC presented his findings at the Sixth Australian...
Workshop on Oil Shale held in Brisbane in December. The microwave retorting yields a greater proportion of lighter hydrocarbons and lower sulfur and nitrogen than conventional retorting. The oil is readily hydrotreated to produce a synthetic crude oil which is a viable source of distillate fuels of specification quality.

A positive Quality Differential (QD) of over US$1.00 per barrel was calculated as a basis for economic comparison of the hydrotreated product against Saudi Arabian light crude oil. According to the author, these results indicate that the addition of a microwave-retorting stage to a shale processing plant could result in a value-added refinery feedstock.

Background

This research at MARC began as part of a study of the variable and sometimes puzzling heating effects obtained when minerals and mineral bearing rocks were heated by microwave energy. Different shales were found to be quite different in their receptivity to microwave heating and this was thought to be related to the presence in some shales of minerals such as titanium dioxide, or traces of residual moisture, either of which result in a dielectric loss at microwave frequencies. In the course of these tests, it was found that microwave energy could be used efficiently for retorting crushed shale and gave rise to an improved product in high yield.

In order to obtain a measure of the added value of the microwave-retorted oil, a larger sample was prepared for hydrotreatment and the resulting synthetic crude oil subjected to fractional distillation, and a series of standard tests leading to a QD value. Before deregulation of the Australian oil industry, the QD was used to determine the Import Parity Price for Australian crude oils. It provides an indication of the value per barrel of the oil to a refiner, relative to that of Saudi Arabian light crude oil.

Results

The results of the predrying and preheating experiments confirmed the key role which water plays in the microwave heating process. At constant microwave power, the retorting time increased for predried shale. The yield was also reduced because of the lower temperature reached. However, gas preheating after drying restored the retorting time and also the oil yield to approximately their former levels. The implication for a commercial process is that the use of microwave power should be limited to temperatures of not less than 260°C or possibly 300°C. The energy required to decompose the kerogen and heat the dry shale from 300 to 480°C is a minor fraction of the whole, and it is in this temperature range, rather than in the drying and preheating stages, where microwave energy can be most efficiently used.

The hydrotreatment of the microwave-retorted oil proved to be achievable under relatively mild conditions. Under the least severe conditions (330°C, 10 mPa, 1 hour) all olefins were converted to alkanes, while nitrogen was reduced by 60 percent to 0.4 weight percent. Nitrogen levels were reduced below 44 ppm under more severe conditions (380°C, 15 mPa, 0.8 hour). Sulfur was relatively easily reduced to <0.1 weight percent. A summary of the analytical data for feedstock and product is presented in Table 1.

### TABLE 1

<table>
<thead>
<tr>
<th>Elemental Composition (Wt%)</th>
<th>Feedstock</th>
<th>Product</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>84.0</td>
<td>85.7</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>12.9</td>
<td>14.3</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>1.0</td>
<td>0.0044</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.8</td>
<td>&lt;0.1</td>
</tr>
<tr>
<td>Oxygen (by diff.)</td>
<td>1.3</td>
<td>0.0</td>
</tr>
<tr>
<td>H/C</td>
<td>1.83</td>
<td>1.99</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Simulated Distillation (Wt%)</th>
<th>Feedstock</th>
<th>Product</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;196°C</td>
<td>13.6</td>
<td>13.6</td>
</tr>
<tr>
<td>196 - 235°C</td>
<td>8.0</td>
<td>9.4</td>
</tr>
<tr>
<td>235 - 317°C</td>
<td>21.6</td>
<td>24.6</td>
</tr>
<tr>
<td>&gt;317°C</td>
<td>56.8</td>
<td>52.4</td>
</tr>
</tbody>
</table>

The OD value calculated from the tests carried out on the various fractions, was US$1.19 per barrel (see Table 2). Although no longer in use in Australia, the QD value is indicative to a refiner of the value of a crude oil, particularly in view of the high distillate content. Further refining would enable the yield of transport fuels to be increased.
Two kerogen samples were oxidized with alkaline permanganate solution. Neutral and basic molecules were separated from the aqueous product mixture by ether extractions. The remaining aqueous phase was then acidified and extracted with ether. The residue from alkaline permanganate oxidation contained large amounts of manganous dioxide, which was removed by treatment with oxalic acid. The residue from one sample dissolved completely, indicating that the kerogen sample had been entirely converted to soluble species.

A sample of the kerogen concentrate was also oxidized in a stepwise manner using a chromic acid solution.

### Results

According to the paper, product mass data for the alkaline permanganate oxidations reveal some interesting differences between the two samples. While the recovery of basic material and soluble acids was similar, that of precipitated acids and residual material was not.

The kerogen concentrate produced large amounts of precipitated acids as well as considerable residual material. One hundred thirty percent of the initial sample weight was recovered as oxidation products and residual material. This suggests retention of much of the initial structure as well as the incorporation of large amounts of oxygen. These data appear to indicate some significant heterogeneities in the kerogen of the Chattanooga shale.

### Conclusions

Infrared analysis of the oxidation products indicated the presence of aromatic and aliphatic material. Functionalities included alcohols, thiols, phenols, ethers, esters, quinones, and carboxylic acid groups.

Gas chromatography-mass spectrometry analysis confirmed that both aromatic and aliphatic material was present in the oxidation products. Carbon skeletons of the products were found to consist of substituted benzenes, saturated and unsaturated cyclic structures, and n-alkyl chains. Molecular sizes ranged from 10 to 30 carbons. The largest molecules were interpreted as n-alkanes and n-saturated monocarboxylic acids. Aromatic material was typically multifunctional, and was probably responsible for most of the cross-linking within the kerogen.
International Oil Shale Activities in China Updated

D. Peng and J. Qian discuss oil shale activities in China in the Estonian publication Oil Shale. The authors state that China has approximately 7.7 billion tonnes of shale in the Fushun and Maoming reserves. Current annual production from these reserves amounts to 200,000 tonnes. Shale is primarily processed for retorting using the Fushun type of retort for small- to medium-size oil plants. Additional technology for processing shale is being anticipated for the 1990s.

Total proven reserves in China amount to about 32 billion tonnes, while estimated resources reach 700 billion tonnes, the equivalent of 40 billion tonnes of shale oil.

Major Oil Shale Mining Areas

The proven oil shale reserves in the mining areas in Fushun, Maoming and Huadian amount to more than 10 billion tonnes. Promising oil shale deposits can also be found in some other areas. Major oil shale mining areas are Fushun, Maoming, Huadian and Huang counties.

Fushun, Liaoning Province. The Fushun mining area has been exploited for 60 years. It contains 3.6 billion tonnes of shale and the Fischer Assay is 4.7 percent.

In the open-pit mining of coal, the overlying oil shale layer is stripped off. In spite of the relatively low Fischer Assay, the retorting of the oil shale, a byproduct of coal mining, is profitable because of its low production cost. The shale ash can be used as backfill in Fushun underground coal mines.

Maoming, Guangdong Province. The Maoming mining area is one of the major oil shale deposits discovered after the founding of new China, with wide acreage, rich resources and clearly known geological conditions. The average Fischer Assay of oil shale is 6 to 8 percent. The proved recoverable reserves are estimated at 4.17 billion tonnes. The deposit is of shallow bedding and has been subject to open-pit mining for more than 20 years (Jintang Mine). Recently, high quality kaolinite was discovered in the upper part of the oil shale.

Huadian, Jilin Province. The total reserves in this area are estimated at 1.3 billion tonnes, the Fischer Assay being 6 to 12 percent. Oil shale mining in Huadian began in 1943 and was completed in 1961 because of the high cost of underground mining.

Huang County, Shangdong Province. The oil shale is found in an area of about 200 square kilometers at a depth of 0 to 1,000 meters. The oil shale has a Fischer Assay of 9 to 22 percent and an average calorific value of 12,000 kilojoules per kilogram. It is a fairly high-grade deposit found in recent years, and is now mined underground along with brown coal and used as fuel for power generation.

Production of Shale Oil

The shale oil industry in China has existed for 60 years. The highest record of annual shale oil production in the 1950s was 780,000 tonnes. Gasoline, kerosene, diesel fuel, wax and synthetic lubricating oil were produced from shale oil. With the development of the Daqing Oil Field starting from 1962, more emphasis was paid to crude oil; the development of shale oil industry was slowed down.

One shale oil plant in Refinery No. 2 in Fushun, has an annual shale oil production of 100,000 tonnes. The Maoming Petroleum Industry Corporation has a yearly production of 100,000 tonnes of shale oil. Therefore, the total annual shale oil production in China amounts to about 200,000 tonnes.

Direct Combustion of Oil Shale

In Huang County of Shangdong Province, oil shale and brown coal are mined underground and used as solid fuels for boilers and small-scale power generation.

At the Maoming Petroleum Industry Corporation, a small-scale fluid-bed boiler has been built with the capacity of 15 tonnes of steam per hour. Shale particles less than 8 millimeters in size which cannot be processed in the Fushun type retort, are used as solid fuel in the boilers.

In recent years, both in Fushun and Maoming, fluidized combustion boilers with the capacity of 35 tonnes of steam per hour have been built and put into use for power generation.

Achievements in the 1980s

In the 1980s, greater success was achieved due to economic reform and an open-door policy. Decisions were made to enforce research and technology innovation with the aim of higher shale oil yield, higher output of the retort, higher automation levels, lower energy consumption, and lower environmental pollution.

Looking Forward to the 1990s

In the 1990s, a rise in the world market price of crude oil will stimulate the production of shale oil in the world, as a whole, including China. It is expected, according to the authors, that in the 1990s there will be the following developments in oil shale in China:

- Some regional governments are going to promote the development of a shale oil industry and will reduce taxes.
A new shale oil plant is being built in the coal mining area for retorting of oil shale, a byproduct of open-pit mining of coal.

In energy-deficient regions, it is planned to build fluid-bed combustion boilers for power generation by using particulate oil shale as fuel.

The existing retorting plant will be modified by using new technology for drying Maoming oil shale with higher water content (18 percent) and a new type of retort will be developed instead of the older one.

More attention will be paid to the chemical utilization of shale oil, such as production of wax and anticorrosive reagents.

FLUIDIZED BED RETORTING ENHANCES YIELD OF MOROCCAN OIL SHALE

In a paper authored by U.M. Graham, et al., pyrolysis characteristics of oil shales from the Timahdit and Tarfaya deposits were investigated in fixed bed, nitrogen-swept fixed bed and fluidized bed pyrolysis. The objectives were to determine the effects of pyrolysis conditions on product yields and distribution of the pyrolyzed shales. Modified Fischer Assay for the shales resulted in oil yields ranging between 13.2 and 20.4 gallons per ton. Fluidization resulted in shale oil yields ranging from 133 to 157 percent of modified Fischer Assays.

The paper was presented at the American Chemical Society's Fuel Chemistry Division symposium held in San Francisco, California in April.

Organic carbon contents for Moroccan shales, averaging between 11 and 13 percent, are similar to both Western and Eastern United States oil shales. When Western United States oil shale technologies are applied to Moroccan shales, a significant amount of carbon is left on the spent shales and large amounts of offgases are generated. Fluidized bed retorting has been shown to enhance oil yields when applied to Eastern United States oil shale by minimizing retrograde oil reactions. This is accomplished by providing rapid heat up and product sweep.

Modified Fischer Assay

A single fixed bed retorting system was used to determine the Fischer Assay pyrolysis characteristics of seven oil shale zones. The study's operating conditions included a linear heating rate of 12°C per minute during oil evolution and a 30 minute soak time at a maximum retort temperature of 550°C. The purpose of the modified Fischer Assay experiments was to establish oil yield data for the shale samples that were used in the fluid bed retort experiments.

Nitrogen-Swept Fixed Bed Experiments

Operationally, a continuous stream of nitrogen gas was allowed to enter the pyrolysis zone after being heated to 550°C. The nitrogen stream swept oil vapors and a small amount of fines into the product collection system. The purpose of the nitrogen-swept fixed bed runs was to determine variations in oil yields caused when the contact time between oil vapors and shale particles was reduced.

Bench-Scale Fluidized Bed Experiments

A 1.5 inch diameter reactor was used for fluid bed pyrolysis in the study. A screw feeder was calibrated to add raw shale at a feeding rate of 2.0 grams per minute into the reactor. Helium gas was used as the fluidizing medium. The volumetric helium flow rate at bed temperature (550°C) and pressure (1 atmosphere) was adjusted to 28 liters per minute and provided for a shale residence time of approximately 20 minutes.

Results

The analyses indicated major differences in moisture, ash and sulfur contents between the Timahdit and Tarfaya oil shales. Results of material balances for modified Fischer Assay runs and nitrogen-swept fixed bed experiments demonstrated that the latter pyrolysis method caused a slight enhancement in oil recovery. Modified Fischer Assay for the shales resulted in oil yields ranging between 13.2 and 20.4 gallons per ton and oil yields obtained in the nitrogen-swept fixed bed retorting experiments were in the range of 15.7 to 21.6 gallons per ton. Therefore, a maximum oil yield increase of 21 percent was achieved by mobilizing oil vapors with a continuous flow of nitrogen gas. Also, a decrease of offgas emission was recorded, suggesting that vapor phase cracking was reduced.

Fluidized bed pyrolysis resulted in oil yields in excess of the modified Fischer Assay and nitrogen-swept fixed bed pyrolysis (Figure 1). Fluidized bed retorting was performed for three of the seven shale samples. Oil yields obtained from the bench-scale fluid bed retort were based on oil collected in the trapping system.

Using the 1.5 inch diameter fluid bed retort, at 550°C operating temperature, 55 to 60 percent of the carbon was removed from the Timahdit shale samples and 65 percent of the carbon was removed from the Tarfaya shale. Material balances indicated oil yields for the Timahdit and Tarfaya shale samples to vary between 133 and 157 percent of those of the Fischer Assay runs.
Fluidized beds provide not only enhanced oil yields under relatively non-severe conditions, but also leave the pyrolyzed shale with much less remaining sulfur.

###

CO-RETORTING OF TORBANITE AND CANNEL COAL STUDIED FOR ALPHA DEPOSIT

A.C. Hutton, et al., of the University of Wollongong in Australia discussed the co-retorting of torbanite and cannel coal at the 25th Oil Shale Symposium in Golden, Colorado in April. Their analysis of modified Fischer Assay oils and flash pyrolyzates from cannel coal, torbanite and a 2:1 mixture of cannel coal/torbanite shows that the oil derived from the mixture contains components derived from both parent lithologies. Modified Fischer Assay data are listed in Table 1.

Permian Alpha torbanite (a variety of oil shale) and cannel coal were fed into a retort as a mixed feedstock. The characteristics of the oils derived from torbanite include alkene/alkane pairs up to C_{31} and an abundance of components with carbon numbers greater than C_{20} to C_{22}. Oils derived from cannel coal are composed of alkene/alkane pairs ranging from C_{10} to C_{30} with a maximum at C_{23}, and a much higher abundance of aromatic compounds compared to torbanite oils. The resultant oil from the retort displays characteristics from both lithologies.

**Background**

The Alpha torbanite deposit is located in central Queensland, Australia, approximately 750 kilometers northwest of Brisbane and south of the Bowen Basin, one of Australia's two largest coal mining centers. The oil shale resource comprises an upper cannel coal seam and a lower cannel coal seam which has an enclosed torbanite lens.

The most recent resource assessment was based on a 45 hole drilling program undertaken by Alpha Resources Pty. Ltd. as well as the earlier Department of Mines drilling programs. Total resources of the deposit are 89.5 x 10^6 barrels of oil equivalent comprising 7.1 x 10^8 barrels of oil equivalent in the torbanite and 82.4 x 10^6 barrels of oil equivalent in the cannel coal. Block 2, which contains the torbanite lens, has
TABLE 1

MODIFIED FISCHER ASSAY DATA

<table>
<thead>
<tr>
<th>Sample</th>
<th>Locality</th>
<th>Oil Yield</th>
<th>H₂O</th>
<th>Gas/Loss</th>
<th>Oil Sp.Gr.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Torbanite</td>
<td>ALPHA</td>
<td>701</td>
<td>18.4</td>
<td>8.4</td>
<td>0.890</td>
</tr>
<tr>
<td>Torbanite</td>
<td>Joadja</td>
<td>612</td>
<td>0.6</td>
<td>4.1</td>
<td>0.891</td>
</tr>
<tr>
<td>Torbanite</td>
<td>Marrangaroo</td>
<td>489</td>
<td>1.4</td>
<td>4.4</td>
<td>0.887</td>
</tr>
<tr>
<td>Cannel Coal¹</td>
<td>ALPHA</td>
<td>100</td>
<td>19.6</td>
<td>8.0</td>
<td>0.951</td>
</tr>
<tr>
<td>Cannel Coal¹</td>
<td></td>
<td>72</td>
<td>20.3</td>
<td>9.4</td>
<td>0.918</td>
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<tr>
<td>Cannel Coal¹</td>
<td></td>
<td>75</td>
<td>22.7</td>
<td>7.5</td>
<td>0.944</td>
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<tr>
<td>Cannel Coal²</td>
<td></td>
<td>44</td>
<td>19.5</td>
<td>8.8</td>
<td>0.975</td>
</tr>
<tr>
<td>Cannel Coal²</td>
<td></td>
<td>70</td>
<td>16.2</td>
<td>8.1</td>
<td>0.944</td>
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<tr>
<td>Cannel Coal²</td>
<td></td>
<td>101</td>
<td>18.2</td>
<td>7.5</td>
<td>0.982</td>
</tr>
<tr>
<td>Mixture⁴</td>
<td>ALPHA</td>
<td>343</td>
<td>12.8</td>
<td>7.9</td>
<td>0.913</td>
</tr>
</tbody>
</table>

¹ upper seam
² lower seam
³ coal used in the coal/torbanite mixture
⁴ mixture of 2:1 cannel coal to torbanite

33.6 x 10⁶ barrels of oil equivalent and is the only block for which mining is presently proposed.

Torbanite is olive black to black, has a distinctive conchoidal fracture and a woody sound when struck with a hammer. Modified Fischer Assays for 145 samples of torbanite from 28 holes gave values ranging from 200 to 650 liters per tonne with an average of 42 liters per tonne.

The cannel coal is a dull coal with a few bright bands and is brownish-black to black. Oil yield, measured by modified Fischer Assay, for 44 samples taken from 18 holes gave values ranging from 30 to 254 liters per tonne.

Mining and Utilization Considerations

One mining plan proposes a 10 year mine life producing 200,000 tonnes of shale per year. Although the deposit is small compared to the Queensland Tertiary deposits, the Alpha deposit has three favorable features:

- The high yield from the torbanite is sufficient to offset the limited size of the deposit.
- The deposit is very shallow and can be mined by open cast methods with steep high walls because the overburden is predominantly competent sandstone.
- Preliminary studies indicate that the torbanite is suitable for a bitumen-based product mix.

Australia uses 600,000 tonnes of bitumen per year, which are derived entirely from Middle East crude and produced at seven Australian refineries at a minimum price of A$300 to $350 per tonne. This represents sales of at least A$180 million per year of which 29 percent is used in New South Wales, 25 percent in Victoria and 22 percent in Queensland. An Alpha mine, producing 500,000 tonnes of torbanite per year (10,000 tonnes per week) would supply 170,000 tonnes of bitumen—more than the total annual Queensland bitumen consumption.

Australia needs an indigenous source of crude for bitumen manufacture, but this is unlikely to be a natural crude unless significant reserves of non-waxy, heavy crude are discovered, because most Australian crudes are sourced from terrestrial plants. Thus, the only potential significant Australian source of bitumen is from oil shales. Previous studies have already shown that Tertiary oil shales produce bitumen with properties that are comparable to those of commercially produced bitumen using Middle East crude.

Prospects for mining the oil shale resource at Alpha would be greatly enhanced if the cannel coal and torbanite in the lower seam could be retorted as a single entity given the intimate association of the two.

Oils

Despite the lower rates of heating in the modified Fischer Assay process compared to microscale flash pyrolysis, the respective oils for the cannel coal and torbanite samples were similar with the following minor differences:
The modified Fischer Assay oils have a slightly higher relative abundance of aromatics (where these are present) and a larger proportion of alkenes at each carbon number with the alkene/alkane ratio increasing with increasing carbon number.

The modified Fischer Assay oils have a slightly higher proportion of low carbon number alkanes and alkenes. Where C28 to C31 terpene and plant wax components are present in some flash pyrolyzates, they are absent in the corresponding modified Fischer Assay oil.

The oils from the coal/torbanite mixture showed both the aromatic compounds derived from coals and the typical torbanite homologous alkene/alkane pairs. No other compounds appeared to have been formed by pyrolyzing the mixture compared to pyrolyzing the separate coal and torbanite.

Future Research

Studies are now required to determine if the cannel coal and torbanite of the Permian Alpha resource can be retorted as a mixture on a larger scale. The spent torbanite and cannel coal contain abundant carbon and could be used as a source of heat energy in retorting processes.

 QUEENSLAND OIL SHALE RESOURCES REVIEWED

S.G. Matheson of the Queensland Department of Resource Industries in Brisbane, Australia presented an overview of the Queensland oil shale resources at the Sixth Australian Workshop on Oil Shale last December. According to Matheson there are 12 oil shale deposits throughout Queensland. The total estimated resource of shale oil contained within these deposits is 28.8 billion barrels.

Queensland contains the majority of the presently identified oil shale resources in Australia. Oil shale has not been economically worked in Queensland, but considerable exploration was undertaken during World War II and since the oil crises of 1973 and 1979.

An upsurge in exploration activity in 1974 resulted from the first rapid rise in the price of oil, and exploration peaked between 1978 and 1981, following an even greater price rise. In 1982 the world glut of oil brought a decline in activity and since 1983 the number of exploration areas has remained low. The sharp drop in the price of crude oil from US$28 per barrel in February 1986 to a low of US$8 per barrel in August 1986 was a significant disincentive to the production of shale oil. The price of oil has been relatively stable since February 1991 at around US$20 per barrel.

Approximately two-thirds of the total resource figure for Queensland is held in four deposits (Condor, Yaamba, Rundle, and Stuart). Resource figures for each deposit are outlined in Table 1. These reported shale oil resources are essentially summaries of figures supplied by companies during regular reporting of exploration. The total recoverable resource figure may be significantly less than these estimates due to:

- The level of accuracy of the resource estimates
- Inclusion of resources at depths beyond the current limits of open-cut mining methods
- Failure to take account of moisture content of the oil shale in some estimates
- Environmental considerations which may limit the extent or viability of mining of some deposits
- Uncertainty regarding mining and processing recovery factors

The majority of Queensland's oil shale resources are located in small Tertiary basins adjacent to the central eastern coastline of the state (Figure 1). The Tertiary oil shales were deposited in shallow freshwater lacustrine environments and are comparatively soft with high moisture contents of around 20 to 30 percent.

Alpha Deposit

The Alpha deposit is estimated to contain a total of 90 million barrels of shale oil, of which 7 million barrels is derived from torbanite. Broad-based environmental and mining studies have been conducted and a mine plan has been prepared recently for a 200,000 tonne per year mine with a production life of 10 years. Recent retorting studies have concentrated on the production of asphaltenes and bitumen related compounds.

Condor

The Condor deposit is located south of Proserpine and contains the largest proven deposit of oil shale in Queensland. The deposit lies within the Hillsborough Basin which extends offshore under Repulse Bay. The brownish-black and brown oil shale units within the Tertiary sequence are about 400 meters thick of which 200 meters constitute the main economic zone of interest.

Duaringa

The Duaringa oil shale resource comprises three separate deposits within the Duaringa Basin, 110 kilometers west of
TABLE 1

RESOURCE ESTIMATES FOR QUEENSLAND OIL SHALE DEPOSITS

<table>
<thead>
<tr>
<th>Deposit</th>
<th>Operating Company</th>
<th>Billion Barrels</th>
<th>Average Oil Yield (liters per ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alpha</td>
<td>Alpha Resources P/L</td>
<td>0.09</td>
<td>148</td>
</tr>
<tr>
<td>Condor</td>
<td>SPP/CPM</td>
<td>9.65</td>
<td>66.8</td>
</tr>
<tr>
<td>Duaringa</td>
<td>SPP/CPM</td>
<td>3.72</td>
<td>82.4</td>
</tr>
<tr>
<td>Herbert Creek</td>
<td>Peabody Aust. P/L</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Julia Creek</td>
<td>CRA Explor. &amp; untenured</td>
<td>1.50</td>
<td>60.2</td>
</tr>
<tr>
<td>Lowmead</td>
<td>SPP/CPM</td>
<td>0.736</td>
<td>84.2</td>
</tr>
<tr>
<td>Mount Coolon</td>
<td>IMC</td>
<td>0.174</td>
<td>136</td>
</tr>
<tr>
<td>Nagoorin</td>
<td>SPP/CPM</td>
<td>2.65</td>
<td>90.8</td>
</tr>
<tr>
<td>Nagoorin South</td>
<td>SPP/CPM</td>
<td>0.467</td>
<td>78.1</td>
</tr>
<tr>
<td>Rundle</td>
<td>Esso</td>
<td>2.65</td>
<td>105</td>
</tr>
<tr>
<td>Stuart</td>
<td>SPP/CPM</td>
<td>3.05</td>
<td>94.1</td>
</tr>
<tr>
<td>Yaamba</td>
<td>Peabody Aust. P/L</td>
<td>4.14</td>
<td>95.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>28.8</strong></td>
<td></td>
</tr>
</tbody>
</table>

Rockhampton. Two flat lying oil shale seams within a stratigraphic interval of 75 meters occur over much of the basin, but the kerogen content of the upper seam has been weathered and eroded in some areas. The bulk of open-cut resources lie within the lower seam which averages 34 meters in thickness.

**Herbert Creek**

The Herbert Creek Basin has been under investigation since 1978 when oil shale was discovered in Yaamba Basin to the southwest.

The Herbert Creek Basin contains over 600 meters of Tertiary sediments which are overlain in most areas by Quaternary sand, clay and gravel. An inferred in situ resource of 570 million barrels of shale oil to a depth of 270 meters has been located by recent exploration.

**Julia Creek**

The Julia Creek oil deposit ranges in thickness from 7 to 16 meters. CSR Exploration undertook an extensive prefeasibility study in 1980 which indicated that significant cost reductions were needed in the high cost areas of mining, retorting and power supply for the project to be competitive.

**Lowmead**

The Lowmead deposit is located in a small basin southeast of Gladstone. Three main oil shale members have been identified within a 700 meter thick Tertiary lacustrine sequence. The deposit is characterized by a sequence of interbedded carbonaceous oil shale (brown coal dominated) and non-carbonaceous oil shale (lamosite) members.

**Mt. Coolon**

International Mining Corporation has located a small resource known as the Bungobine deposit within the Tertiary Suttor Formation. The deposit lies 30 kilometers northwest of Mt. Coolon.

The Suttor Formation is the upper part of an extensive fluvial and lacustrine sequence which was deposited over an irregular basement. Brown oil shale alternates in cyclic sequences with kaolinitic clays and brown lignitic oil shales. Moisture content of the oil shale is high (up to 50 percent as received) which will affect oil yield after processing.

**Nagoorin/Nagoorin South**

The Nagoorin and Nagoorin South deposits lie within the Nagoorin Graben southwest of Gladstone.

It extends in a northwesterly direction along the course of the Boyne River. At least 1,300 meters of Tertiary sediments have been inferred in the Graben. Unit C is the thickest of five units and contains alternating seams of cannel coal and lamosite (brown oil shale).
Rundle

The Rundle deposit is held by Esso Exploration and Production Australia Inc. and Southern Pacific Petroleum/Central Pacific Mineral. Over $39 million has been spent on the project so far.

Over 100 reports on the Rundle deposit have been prepared including a major feasibility study—the Rundle Commercialization study—which was completed in 1984.

Stuart

The Stuart oil shale deposit is located 12 kilometers northwest of Gladstone and is close to existing power, water, port and other support facilities.

The Stuart deposit is part of the Tertiary Narrows Graben. Detailed exploration over the last 11 years has delineated a resource of shale oil of 3 billion barrels of which approximately 120 million barrels is contained within the
Kerosene Creek Member. More recent mining studies for the proposed Stage 1 mine area have defined 36 million tonnes of oil shale within the Kerosene Creek Member at an average grade of 172 liters per tonne and an average stripping ratio of 1.4:1.

Yaamba

The Yaamba deposit straddles the Bruce Highway 30 kilometers northwest of Rockhampton.
CONCEPT OF SUSTAINABLE DEVELOPMENT EXPLORED FOR OIL SHALE

The concept of sustainable development has gained wide acceptance as a principle for evaluating the desirability of plans and projects from a resources and environmental perspective. E. Stock, et al., of Griffith University in Nathan, Australia, have studied the areas of concern including site management and rehabilitation practices and the assessment of environmental impacts off-site. While there is considerable debate about the definition of sustainable development, nonetheless, the implications of the concept for the oil shale industry are worthy of investigation. The authors presented their study at the Sixth Australian Workshop on Oil Shale in December 1991, reviewing these issues with respect to mining at the Rundle Project and mining in general.

The concept of sustainable development has gained international acceptance as a framework for resource and environmental policy. There is a challenge now to translate the concept to the level of particular industries such as oil shale and to specific projects such as Rundle.

Future oil shale production in Australia will depend substantially on Commonwealth energy and trade policies, and on environmental policies at all levels of government. Given the potentially large environmental impacts of oil production and processing, the future of the industry may well be shaped by the sustainable development debate.

The World Commission on Environment and Development defined sustainable development as "development that meets the needs of the present without compromising the ability of future generations to meet their own needs." The term has been criticized because it seems ambiguous and is open to a wide range of interpretations, many of which are contradictory. The confusion has been caused because "sustainable development," "sustainable growth," and "sustainable use" have been used interchangeably, as if their meanings were the same. They are not. "Sustainability" is a characteristic of a process or a state that can be maintained indefinitely (for all practical purposes). "Sustainable growth" is a contradiction in terms: nothing physical can grow indefinitely. "Sustainable use" is applicable only to renewable resources: it means using them at rates within their capacity for renewal. An Australian Government definition for ecological sustainable development also needs consideration: "Ecologically Sustainable Development" (ESD) is defined as "using, conserving and enhancing the community's resources so that ecological processes, on which life depends, are maintained, and the total quality of life, now and in the future can be increased."

The Main Principles of Sustainability

Stock says that for sustainable development of renewable resources such as forests and fisheries, the implications are relatively clear, that the rate of use should not exceed the rate of regeneration. For nonrenewable resources such as minerals or fossil energy resources, the rate of use should not exceed the capacity to find new resources, acceptable substitutes or to recycle.

Many economists argue that for sustainable development, a suitable criterion is that the stock of capital bequeathed to future generations is at least as large as that existing at present. Capital in this context is defined to include both natural resources capital, built capital in the form of production infrastructure and human capital including technology. This wider definition of sustainability allows for substitution between natural and human-made capital.

The main principles in action statements look like this:

- Limit human impact on the biosphere to a level that is within carrying capacity.
- Maintain the stock of biological wealth:
  - Maintain life-support services.
  - Conserve the variety of life in all its forms.
  - Use renewable resources at rates within their capacity for renewal.
- Use nonrenewable resources at rates that do not exceed the creation of renewable substitutes.
- Aim for an equitable distribution of the benefits and costs of resource use and environmental management.
- Promote technologies that increase the benefits from a given stock of resource.
- Use economic policy to help maintain natural wealth.
- Adopt an anticipatory, cross-sectoral approach to decision making.
- Promote and support cultural values compatible with sustainability.

The Commonwealth Government formed nine industry sector working groups to examine ESD, commencing in
November 1990. Membership of the working groups represented Commonwealth and state governments, industry, unions, conservation groups, consumer and social welfare organizations.

Based on the Prime Minister's direction, the Working Group considered the following objectives:

- Improving material and non-material well being
- Providing intergenerational equity
- Maintaining biodiversity and ecological systems
- Recognizing global dimensions
- Dealing cautiously with risk and uncertainty

The task facing the ESD working groups was "to provide advice to governments on future policy directions and develop practical proposals for implementing them."

**Sustainable Development in Mining**

Under ESD conditions the mining industry is being asked very difficult questions:

- Will this project contribute to net community benefit?
- What is the industry's degree of responsibility to Aboriginal people affected by a project?
- What "values" does this area to be mined have on the Register of the National Estate?
- Will the removal of this habitat in preparation for mining truly reduce biodiversity?
- Does this fossil-fuel development project contribute significantly to the burden of greenhouse gases?

**Energy Use and Greenhouse Gases**

A particular area of concern that deserves closer examination under ESD is a formal energy analysis of mining and petroleum projects and an accounting of the associated production of greenhouse gases. ESD principles suggest that projects with small demands for overall energy and limited production should be favored, other things being equal.

It costs energy to locate, extract from the ground, transport and process minerals into forms suitable for consumption. There was an early start on energy accounting in the 1970s but it has not been followed up. There is an intimate connection between grades of ore and where most energy is consumed in the production system (extraction compared with smelting) and the energy cost per tonne.

With fuels it is not possible to assign a grade to fuel resources. In general, however, an oil shale project yielding less than about 100 liters per tonne is not likely to be sustainable.

In June 1991 the Federal Minister for Resources confirmed that the government could continue an exemption from excise on gasoline produced from approved oil shale demonstration plants to the year 2005. This was gauged to encourage development of a demonstration plant at Stuart for the daily production of 4,400 barrels of liquid fuels. Production of synthetic fuel from this plant over the decade 1995-2005 would more than double the greenhouse gas emissions per liter compared with gasoline sourced from petroleum liquids. Will this project bear the scrutiny of an ESD test? What is the future of other oil shale projects?

**Sustainable Development and the Rundle Project**

According to the authors, for the Rundle Oil Shale Project there appear to be four major sustainable development questions:

- Can the resource be extracted with a favorable balance sheet after an analysis of energy inputs and outputs and the production of greenhouse gases?

The answer to this question would involve an energy analysis which also should consider the output of retorting a feed stock for a petrochemical industry as well as the more conventional gasoline for transport.

- Could there be major damage to coastal ecosystems in the Marine Park and to commercial and recreational fisheries?

According to the authors, worst case scenarios should be considered so that the cost of fail-safe procedures can be put into the feasibility studies.

- Could there be damage to the National Estate values of the Rundle-Balaclava Continuum Area contiguous to the mining area?

Scenarios need to be developed considering synergistic off-site impacts caused by spillovers from the air, fire and other human intrusions.

- Could mining methods which produce large waste dumps and final voids be unacceptable in aesthetic and environmental terms?

The paper says that climatic and water quality scenarios should be developed to forecast situations during and after mining.

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SYNTHETIC FUELS REPORT, JUNE 1992
DOE ISSUES REPORT ON ENVIRONMENTAL ANALYSIS OF CANCELED OXY PROGRAM

Occidental Oil Shale, Incorporated withdrew from its proposed oil shale demonstration project in northwest Colorado in 1991. The "Proof-of-Concept Oil Shale Facility Environmental Analysis Program" has just recently been released, however. The report, prepared by the National Research Center for Coal and Energy at West Virginia University, evaluates the environmental health and safety aspects of modified in situ (MIS) and circulating fluidized bed combustor (CFBC) technologies which were planned for the demonstration plant.

The Proof-of-Concept Project

One of the most important objectives of the project was to verify the environmental acceptability of the technologies being employed. The focal point of the project was the modified in situ (MIS) process. Some elements of MIS technology are proprietary to Occidental Oil Shale, Inc. (OOSI). The process is based upon retorting broken oil shale in place. It was successfully demonstrated by Retorts 7 and 8 at OOSI's Logan Wash research and demonstration site located near De Beque, Colorado. The proposed project includes a CFBC for the production of steam for plant use and cogenerated electric power. The CFBC is fueled by a combination of MIS off-gas, shale and coal.

Two MIS retorts were planned to operate simultaneously and produce 1,206 barrels per day of raw shale oil. The plan included shale rock and MIS off-gas co-firing with other fuels in the CFBC to produce 35 megawatts of cogenerated power. Some power will be consumed internally by the project, with about 25 megawatts being available for outside sales.

Human Health and Safety

According to the report, workers at this operation could experience contaminants in different physical and chemical states. In addition, health risks connected with the technology of mining, construction, maintenance, operation of a refinery plant, transportation, distribution and testing all may contribute to the specific and unusual threats of oil shale production and use.

None of these risks are exclusive to this industry and none can be considered unprecedented or uncontrollable. Traditional means of safety and of industrial hygiene care are applicable to this particular setting, just as they are applicable to the mining industry in general.

General worker health control measures used in other extractive industries are deemed to be equally applicable in MIS technology.

Mine Safety

The report says that gas is present in the oil shale strata of the Green River formation. The C-b oil shale mine has been classified as a gassy mine by MSHA since January 2, 1980 based on a sample containing 0.289 percent methane. This can be controlled by adequate ventilation and, according to OOSI personnel at the C-b site, no methane has ever been detected by the automatic sensors that are constantly monitoring the mine and the shafts.

Most of this methane comes from groundwater. The problems associated with gas liberated from water inflows have been identified, but because the mining horizons are dry and most water comes from the shafts, the gas will either be highly diluted with intake air or immediately exhausted to the surface. Current estimates of groundwater gas are 48 cubic feet per minute (cfm) and diffusion gas of 5 cfm for a total of 53 cfm. To dilute this to 0.1 percent, only 53,000 cfm of ventilation air will be required. This will pose no problems, according to the report.

As in any fissile shale, oil shale is subject to spalling. The primary area where this is of concern is in the roofs of the underground tunnels, where the safety of personnel and equipment are of concern. OOSI's C-b facility has successfully used roof bolting and wire mesh to control roof fall 5 years after construction.

Based on a review of the documentation provided and the site visit, it was the reviewer's opinion that the OOSI MIS technique is a technically viable option from the perspective of mine worker safety.

Shale Oil Handling/Transportation

The report presents an evaluation of shale oil handling and transportation, with respect to health and safety, in reactivating the Occidental Oil Shale Tract C-b operation near Meeker, Colorado.

There are two options for transportation of the shale oil. Option one would have trucks haul the oil to Unocal's upgrader at Parachute Creek, Colorado. It is estimated that this would require nine tanker truckloads per day, but would not place any significant burden on the route. Option two involves transporting of crude shale oil by truck to a railhead, probably in Rifle, Colorado, and then by rail to remote markets. Both options include conventional technology.

Subsidence

Two mine development plans were proposed during research and development programs of the 1980's. The first mine plan involves clusters of MIS retorts laid out in panel form.
The second plan consists of two parts: one is a room and pillar mining section and the other is an MIS section. Subsidence calculations were performed to determine the size of the shaft pillar using the British National Coal Board method of 1975 and that proposed by Abel and Lee in 1980. The panels were designed not to subside. But the pillar design methods by two separate groups produced considerable differences in pillar strength (2180 psi vs. 670 psi). Figure 1 gives a comparison of pillar strength design methods.

Reclamation

The report continues to say that disturbance of land in the proof-of-concept facility will be limited to the construction of a boiler ash dump and possibly a spent shale dump. Reclamation of surface disturbances around injection holes, coring operations, and installation of the MIS gas collection shaft present few problems to revegetation specialists. Revegetation of such sites can be done quickly and effectively.

Revegetation of boiler ash has not been studied. However, retorted or spent oil shale has been studied extensively. Boiler ash is likely to be similar to spent shale and differs primarily in the addition of some proportion of coal ash and the amount of carbon remaining in the ash. Some spent shales have carbon residues of +4 weight percent while boiler ash carbon content will be much lower (less than 1 percent) and has properties like "Lurgi" spent shale. The characteristics of spent shale that commonly cause problems relative to revegetation are coarse particle size, dark color, high salt content, and low amounts of nitrogen and phosphorous. Practices used to overcome deleterious properties of raw and spent shale are topsoiling, addition of organic matter, fertilization, mulching, irrigation, and seeding of adapted plant species.

The proof-of-concept project would have been a unique opportunity to evaluate the environmental, health and safety aspects of MIS oil shale technology on a small, manageable scale. Several key items were identified which would serve as the focus for information gathering programs during operations. These are listed below.

Air Quality. Simple terrain dispersion models should be evaluated. In addition, the operating variances in emissions should be characterized and figured into any dispersion modeling.

Water. The key unresolved water issues relate to the impact of mine drainage on the stream system and water quality concerns. One of the planned objectives of the demonstration project was to monitor the streamflow and the water quality during actual development. In addition, when the burned retorts are abandoned and flooded, the water quality of the invaded water within and near the retorts should be monitored.

\[ \text{FIGURE 1} \]

**COMPARISON OF PILLAR STRENGTH DESIGN METHODS**

\[
\begin{align*}
\text{PILLAR HEIGHT} &= 50 \text{ FT} \\
\text{DEPTH} &= 1000 \text{ FT} \\
\text{HYDROSTATIC STRESS FIELD} \\
\text{LABORATORY UNAXIAL COMpressive STRENGTH} &= 15,000 \text{ psi} \\
\text{ANGLE OF INTERNAL FRICTION} &= 26^\circ \\
\text{COHESION} &= 2000 \text{ psi} \\
\text{SAFETY FACTOR} &= 14
\end{align*}
\]

Source: DOE

SYNTHETIC FUELS REPORT, JUNE 1992
Solid Waste. The rate of boiler ash production would average about 300,000 tons per year.

Health and Safety. An employee monitoring program would begin with the pre-employment scrutiny to eliminate factors of accrued risk in terms of the individual propensity toward injury or aggravation from exposure conditions of pre-existing employment. Following this baseline appraisal, a periodical surveillance program would monitor both exposure and possible effects. No issues stemming from a gassy mine or retorting in a mine environment have been unresolved.

Land Subsidence, Reclamation. The oil shale rock strength developed by two separate groups shows considerable difference. Thus the pillar strength issue should be reviewed with any new data incorporated into the analysis and a consistent value should be derived based on sound engineering practices. Strength properties of spent shale in the retorts must be determined for evaluation of collapse and confinement potential.

Biological. Endangered species have not been identified on the site to date. The small scale of the project probably precludes major wildlife impacts.

Electric Power Transmission. The proof-of-concept project would not require additional transmission capacity. Upon identification of markets for the produced electricity it would be possible to evaluate required changes in the system downstream from the plant site.

BENCH-SCALE TESTS SHOW REVERSE COMBUSTION EFFECTIVE AT REMOVING MIS ORGANIC RESIDUE

F.A. Barbour of Western Research Institute and J.E. Boysen of Resource Technology Corporation, Inc. conducted research to evaluate in situ retort stabilization methods. They reported on their work at the 25th Oil Shale Symposium held in Golden, Colorado in April. The objective of the bench-scale simulations was to evaluate possible post-retorting operating procedures for the optimum cleaning of spent retorts.

Project History

Occidental Oil Shale Inc. (OOSI) successfully demonstrated its modified in situ (MIS) oil shale retorting technology by conducting large-scale field tests at its Logan Wash facility near De Beque, Colorado. OOSI operated the Logan Wash MIS retorting facility from 1972 until 1982. The MIS technology developed by OOSI was proven technically feasible, and commercial projections suggest that the technology can be profitable in the future.

One of the environmental concerns surrounding MIS retorting technology is the impact of the process on local groundwater. Chemical compounds that will solubilize in groundwater are created during MIS retorting. The hot spent retorts must be cooled and then cleaned of these water-soluble chemical compounds to mitigate the process impact on local groundwater. Spent retorts were cooled and cleaned at Logan Wash by circulating water through the retorts to remove soluble materials. Water produced from the MIS retorts (process water) was used in the cooling and initial stages of the cleaning. Groundwater collected in the mine sumps (mine water) was used in the later stages of the cleaning. The groundwater quality from most spent retorts at Logan Wash was restored to near baseline. These experiments demonstrated that the impact on groundwater quality from MIS retorting can be mitigated. However, a commercial-scale operation will require careful water management to ensure that sufficient water is available to clean all spent retorts created.

As a part of the OOSI project studies, Western Research Institute was to evaluate procedures for optimum water management by conducting bench-scale research.

Results of the Water Management Studies

The study showed that reverse combustion is the most effective method for removing organic material on the unretorted shale at the bottom of the retort. Hot quench and deluge after the reverse combustion removed very little additional organic material. Visual inspection of the bottom portion of the retort showed no evidence of organic components after reverse combustion.

The authors found that hot quench was effective in removing most of the organic material near the bottom of the retort. Although the deluge water analyzed after the hot quench suggested that this method was as effective as the reverse combustion, visual examination of the unretorted zone showed that heavy oil was still present. This heavy oil may act as a source of organic contaminants if it undergoes chemical changes that increase its water solubility.

Additional research showed that cool deluge was not as effective as reverse combustion or quench in removing organic material. Water used as a cool deluge removed the least amount of organic material from the unretorted portion of the reactor. The addition of a biodegradable detergent to the cool deluge water was slightly better than using plain water, but it still left a lot of organic material on the unretorted shale.

Reverse combustion reduced water readsoption by spent shale. A carbon layer deposited on the spent shale as a result of reverse combustion provided a barrier to water and reduced the water uptake by the spent shale substantially. A hot quench after reverse combustion removed part of the car-
bon deposit. The removal of the carbon layer was the result of the steam-char reaction taking place during the quench.

The amount of inorganic material leached from the shale was slightly less in the reverse-combustion experiments than in other tests. This is probably related to the water barrier provided by the carbon deposit from the reverse combustion.

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HOUSE PANEL APPROVES LEASING NAVAL SHALE RESERVES FOR GAS PRODUCTION

A United States House of Representatives Interior subcommittee on mining and natural resources has approved a bill to open two Naval Oil Shale Reserves to natural gas drilling and public access. The two reserves, located in northwest Colorado, consist of 55,000 acres. The bill would shift land management of the reserves from the United States Department of Energy (DOE) to the Department of the Interior (DOI). The DOE would retain jurisdiction over the oil shale.

The lands were originally intended to be energy reserves for the military. If the bill is adopted, they would be open to resource exploration with the exception of oil shale. In addition, the lands would be managed, eventually, to include such uses as grazing and recreation.

The sponsor of the bill, Colorado Congressman B. Campbell, anticipates that the revenue generated for the state and local governments from DOI royalties on the land use, plus the revenue from natural gas resource development, would aid the struggling communities on the Western Slope of Colorado.

####
COUNTY USES UNOCAL FUNDS FOR RESEARCH

The Western Colorado Bureau of Economic and Business Research will receive 60 percent of a $100,000 Unocal Corporation grant to Mesa County, Colorado. The gift was an effort to help ease the burden of the closure of the Parachute oil shale plant over a year ago. Of the 480 people employed at the plant, half were residents of Mesa County.

The $60,000 has been allocated for research on local demographic data as an investment in an economic development information base for Mesa County.

Another $13,000 has been allocated for the town of DeBeque for its sewage plant, which had been receiving revenue from Unocal before the oil shale plant was closed.

Almost $3,000 will be given to the Resource Center to support its domestic violence program. According to the Center, a general trend indicates that higher unemployment corresponds to higher incidence of domestic violence. The Center has experienced a 44 percent increase in clients in the domestic violence program since Unocal closed its operation, although it is not clear what percent is related to the plant shutdown.

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OIL SHALE PUBLICATIONS/PATENTS

RECENT PUBLICATIONS

The following presentations were made at the 25th Annual Oil Shale Symposium held in Golden, Colorado, April 21-22:

Hutton, A.C., et al., "Organic Geochemistry of Alpha Torbanite and its Derived Oil Implications for Retorting"

Thorsness, C.B., et al., "Laboratory Measurement of Combustion Kinetics of Retorted Western Oil Shale"

Aldis, D.F., et al., "Oil Shale Ash Layer Thickness and Char Combustion Kinetics"


Munkvold, G., "Fine Particle Retort Kinetics of Tract C-a Oil Shale"

Barbour, F.A., et al., "Bench-Scale Simulation of Quenching and Stabilization of MIS Retorts"

Cena, R.J., et al., "HRS Pilot Plant and Modeling Results"

Yefimov, V.M., et al., "Lower Temperature Processing of Lump Oil Shale in Retorts with a Circular Semicoking Chamber"

Hohmann, J.P., et al., "Petrosix Industrial Plant in Operation"

Gwyn, J.E., "A State-of-the-Art Integrated Process for Oil from Colorado Shales"

McWhorter, D.B., et al., "The Permeability of Lurgi Shale Affected by Cracking and Cooling"

Mushrush, G.W., et al., "Shale-Derived Middle Distillate Fuel Insolubles: Formation Conditions and Characterization"


Evans, J., "Socio-Economic Analysis of a Boom/Bust Cycle"

Nielsen, I., "Nahcolite Rich Oil Shale—World's Richest Mineral Deposit"

The following papers were presented at the American Chemical Society Division of Fuel Chemistry meeting held in San Francisco, California, April 5-10:

Rogers, M., et al., "The Oxidation of the Kerogen of Chattanooga Shale with Alkaline Permanganate and Chromic Acid"

Singleton, M.F., et al., "Coking and Cracking Reactions of Oil Vapor Over Hot Oxidized Oil Shale"

Taulbee, D.N., et al., "Investigation of Product Coking Induced by Hot Recycle Solids in the Kentort II Fluidized Bed Retort"


Mahboub, K., et al., "Evaluation of the Asphalt Application Potential of an Eastern U.S. Shale Oil"

Bunger, J.W., et al., "Market Enhancement of Shale Oil by Selective Separations"

Ross, D.S., "Autoradiographic and Hydrothermal Probes of Interfacial Chemistry in Oil Shale and Coal"
"Process and Catalyst for the Dewaxing of Shale Oil," Suheil Abdo, Eric Moorehead, John Ward - Inventors, Union Oil Company of California, United States Patent Number 5,084,159, January 28, 1992. The pour point and/or cloud point of the lube fractions comprising a waxy hydrocarbon feedstock containing straight and branched chain paraffins is reduced by contacting the feedstock in a dewaxing zone, preferably in the presence of added hydrogen, with a dewaxing catalyst comprising (1) an intermediate pore crystalline molecular sieve having a pore size between about 5.0 Angstroms and about 7.0 Angstroms and (2) a large pore crystalline molecular sieve having a pore size above about 7.0 Angstroms and typically selected from the group consisting of silicoaluminophosphates, ferrosilicates, aluminophosphates and Y zeolites. A hydrocarbon fraction of reduced paraffin content is recovered from the effluent of the dewaxing zone. Preferred intermediate pore crystalline molecular sieves are silicalite and a ZSM-5 type zeolite. Preferred large pore crystalline molecular sieves are silicoaluminophosphates such as SAPO-5 and ammonium exchanged and steamed Y zeolites.

"Acid Treatment of Kerogen-Agglomerated Oil Shale," Terry Marker, Bernard So, Gene Tampa - Inventors, Amoco Corporation, United States Patent Number 5,091,076, February 25, 1992. A kerogen-agglomerated oil shale is contacted with an acid containing solution prior to economically upgrading the oil shale prior to retorting. The kerogen is agglomerated by contacting the oil shale with a two phase mixture of an organic liquid and water to form kerogen-rich agglomerates and mineral-rich particles. Acids suitable for use in this invention include any acid capable of forming a soluble metallic salt, preferably sulfurous acid.

"Method of an Apparatus for Recovering Oil from Solid Hydrocarbonaceous Material," Ludlow Daniels - Inventor, United States Patent Number 5,073,251, December 17, 1991. A method for the recovery of oil from solid hydrocarbonaceous material and particularly from oil shale by retorting fresh feed shale and heat medium particles using a fluidized bed. The invention uses a self supporting dense phase fluidized bed in a retort without the need to use an external fluid for fluidization. Also described is a control system for the method whereby feedstock input rate is controlled as a function of flow rate of oil vapor products given off, and whereby heat medium particle input rate is controlled as a function of the temperature of either the retort bed or of the oil vapor product.
STATUS OF OIL SHALE PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since March 1992)

ACORN PROJECT — (See Stuart Oil Shale Project)

CHATHAM CO-COMBUSTION BOILER — New Brunswick Electric Power Commission (S-30)

Construction on the Chatham circulating bed demonstration project was completed in 1986 with commissioning of the new boiler. A joint venture of Energy, Mines and Resources Canada and the New Brunswick Electric Power Commission, this project consists of a circulating fluidized-bed boiler of Lurgi design that supplies steam to an existing 22-MW turbine generator. High-sulfur coal was co-combusted with carbonate oil shales and also with limestone to compare the power generation and economics of the two cocombustants in the reduction of sulfur emissions. A full capacity performance-guarantee test was carried out in May 1987, on coal, lime and oil shale. Testing with oil shale in 1988 showed shale to be as effective as limestone per unit of calcium contained. However, bulk quantities of oil shale were found to have a lower calcium content than had been expected from early samples. No further oil shale testing is planned until further evaluations are completed.

CLEAR CREEK PROJECT — Chevron Shale Oil Company (70 percent) and Conoco, Inc. (30 percent) (S-40)

Chevron and Conoco successfully completed the operation of their 350 tons per day semi-works plant during 1985. This facility, which was constructed on property adjacent to the Chevron Refinery in Salt Lake City, Utah, was designed to test Chevron Research Company's Staged Turbulent Bed (STB) retort process. Information obtained from the semi-works project would allow Chevron and Conoco to proceed with developing a commercial shale oil operation in the future when economic conditions so dictate.

Chevron and Conoco have joined with Lawrence Livermore National Laboratory (LLNL), DOE and other industrial parties to participate in a 3 year R&D project involving LLNL's Hot Recycled Solids oil shale process. Information obtained from this project may result in refinements to the STB process.

Chevron is continuing to develop and protect its conditional water rights for use in future shale oil operations at its Clear Creek property.

Project Cost: Semi-Works - Estimated at $130 million

COLONY SHALE OIL PROJECT — Exxon Company USA (S-50)

The proposed 47,000 barrels per day project is on Colony Dow West property near Parachute, Colorado. Underground room-and-pillar mining and Tosco II retorting was originally planned. Production would be 66,000 tons per day of 35 gallons per ton shale from a 60-foot horizon in the Mahogany zone. Development was suspended in October 1974.

A draft EIS covering the plant and a 196-mile pipeline to Lisbon, Utah, was released in December 1975 and the final EIS was later issued. EPA issued a conditional prevention of significant deterioration permit in November 1979. Land exchange was consummated on February 1, 1980. On August 1, 1980, Exxon acquired ARCO's 60 percent interest in the project for approximately $400 million. The preferred pipeline destination was changed to Casper, Wyoming, and the final EIS supplement was completed. Work on Battlement Mesa community commenced summer 1980. The Colorado Mined Land Reclamation permit was approved in October 1980.

C.F. Braun was awarded contract for final design and engineering of Tosco II retorts. Brown & Root was to construct the retorts. Stearns-Roger was awarded a contract for design and construction liaison on materials handling and mine support facilities. DOE granted Tosco a $1.1 billion loan guarantee in 1981.

On May 2, 1982, Exxon announced a decision to discontinue funding its 60 percent share of the Colony Shale Oil Project. Tosco responded to the decision by exercising its option to require Exxon to purchase Tosco's 40 percent interest. Exxon has completed an orderly phase down of the project and has sold the partially completed Battlement Mesa complex. An Exxon organization remained in the Parachute area for several years to perform activities including reclamation, some construction, security, safety, maintenance, and environmental monitoring. These activities were designed to maintain the capability for further development of the Colony resource when economics become attractive. In December 1989, Exxon closed its Grand Junction project office. Administration of ongoing site reclamation, maintenance, and environmental monitoring was transferred to the Houston, Texas office.

Project Cost: Estimated in excess of $5 - $6 billion
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

CONDOR PROJECT – Central Pacific Minerals - 50 percent; Southern Pacific Petroleum - 50 percent (S-60)

Southern Pacific Petroleum N.L. and Central Pacific Minerals N.L. (SPP/CPM) announced the completion on June 30, 1984 of the Condor Oil Shale Joint Feasibility Study. SPP/CPM believe that the results of the study support a conclusion that a development of the Condor oil shale deposit would be feasible under the assumptions incorporated in the study.

Under an agreement signed in 1981 between SPP/CPM and Japan Australia Oil Shale Corporation (JAOSCO), the Japanese partner funded the Joint Feasibility Study. JAOSCO consists of the Japan National Oil Corporation and 40 major Japanese companies. The 28 month study was conducted by an engineering team staffed equally by the Japanese and Australian participants and supported by independent international contractors and engineers.

From a range of alternatives considered, a project configuration producing 26.7 million barrels per year of sweet shale oil gave the best economic conclusions. The study indicated that such a plant would have involved a capital cost of US$2,300 million and an annual average operating cost of US$265 million at full production, before tax and royalty. (All figures are based on mid-1983 dollars.) Such a project was estimated to require 12 years to design and complete construction with first product oil in Year 6, and progressive build-up to full production in three further stages at two-year intervals.

The exploration drilling program determined that the Condor main oil shale seam contains at least 8,100 million barrels of oil in situ, measured at a cut-off grade of 50 liters per ton on a dry basis. The case study project would utilize only 600 million barrels, over a nominal 32 year life. The deposit is amenable to open pit mining by large face shovels, feeding to trucks and in-pit breakers, and then by conveyor to surface stockpiles. Spent shale is returned by conveyor initially to surface dumps, and later back into the pit.

Following a survey of available retorting technologies, several proprietary processes were selected for detailed investigation. Pilot plant trials enabled detailed engineering schemes to be developed for each process. Pilot plant testing of Condor oil shale indicated promising results from the "fines" process owned by Lurgi GmbH of Frankfurt, West Germany. Their proposal envisions four retort modules, each processing 50,000 tons per day of shale, to give a total capacity of 200,000 tons per day and a sweet shale oil output, after upgrading, of 82,100 barrels per day.

Raw shale oil from the retort would require further treatment to produce a compatible oil refinery feedstock. Two 41,000 barrels per day upgrading plants are incorporated into the project design.

All aspects of infrastructure supporting such a project were studied, including water and power supplies, work force accommodation, community services and product transportation. A 110 kilometer pipeline to the port of Mackay is favored for transfer of product oil from the plant site to marine tankers. The study indicated that there were no foreseeable infrastructure or environmental issues which would impede development.

Market studies suggested that refiners in both Australia and Japan would place a premium on Condor shale oil of about US$4 per barrel over Arabian Light crude. Average cash operating cost at full production was estimated at US$20 per barrel of which more than US$9 per barrel represents corporation taxes and royalty.

During July 1984 SPP, CPM, and JAOSCO signed an agreement with Japan Oil Shale Engineering Corporation (JOSECO). JOSECO is a separate consortium of thirty-six Japanese companies established with the purpose of studying oil shale and developing oil shale processing technology. Under the agreement, SPP/CPM mined 39,000 tons of oil shale from the Condor deposit, crushed it to produce 20,000 tons and shipped it to Japan in late 1984.

JOSECO commissioned a 250 tonne per day pilot plant in Kyushu in early 1987. The Condor shale sample was processed satisfactorily in the pilot unit.

In 1988 SPP/CPM began studies to assess the feasibility of establishing a semi-commercial demonstration retorting plant at Condor similar to that being designed for the Stuart deposit. Samples of Condor shale were shipped to Canada for testing in the Taciuk process.

Project Cost: $2.3 billion (mid-1983 U.S. dollars)

ESPERANCE OIL SHALE PROJECT – Esperance Minerals NL and Greenvale Mining NL (S-70)

In 1991 Esperance Minerals and Greenvale Mining announced they are planning to produce 200,000 tons per year of "asphaltine" for bitumen from the Alpha torbanite deposit in Queensland, Australia. The two companies believe they can produce bitumen that will sell for more than US$80 per barrel.

The Alpha field contains about 90 million barrels of reserves, but the shale in this deposit has a high yield of 88 to 132 gallons of oil per ton of shale.

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

Recent studies have concluded that using new technologies to produce a bitumen-based product mix would be the most economically beneficial. Byproducts could include diesel fuel and aromatics.

ESTONIA POWER PLANTS – Estonian Republic (S-80)

Two oil shale-fueled power plants, the Baltic with a capacity of 1,435 megawatts and the Estonian with a capacity of 1,600 megawatts, are in operation in the Estonia. These were the first of their kind to be put into operation.

About 95 percent of the oil shale output from the former USSR comes from Estonia and the Leningrad districts of Russia. Half of the extracted oil shale comes from surface mines, the other half from underground workings. Each of the nine underground mines outputs 3,000 to 17,000 tons per day; each of the surface mines outputs 8,000 to 14,000 tons per day.

Exploitation of kukersite (Baltic oil shale) resources was begun by the Estonian government in 1918. In 1980, annual production of oil shale in the USSR reached 37 million tons of which 36 million tons come from the Baltic region. Recovered energy from oil shale was equivalent to the energy in 49 million barrels of oil. Most extracted oil shale is used for power production rather than oil recovery. In 1989, annual production of oil shale in the Baltic region was as low as 28 million tons. In 1991, annual production of oil shale in Estonia was 19 million tons. About 10 million tons were extracted from six underground mines and about 9 million tons from three open pit mines. The annual output from the underground mines ranged from 600,000 to 4.5 million tons, while the output from the surface mines ranged from 2.0 to 4.5 million tons. The recovered energy from this oil shale was the energy equivalent of 25 million barrels of oil.

Most extracted oil shale (85 percent) is used for power production rather than oil recovery. More than 60 percent of Estonia's thermal energy demand is met by the use of oil shale. Fuel gas production was terminated in 1987.

Pulverized oil shale ash is being used in the cement industry and for acid soil melioration.

FUSHUN COMMERCIAL SHALE OIL PLANT – Fushun Petrochemical Corporation, SINOPEC, Fushun, China (S-90)

The oil shale retorting industry in Fushun, China began in 1928 and has been operating for 60 years. Annual production of shale oil topped 780,000 tons in 1959. In that period, shale oil accounted for 30-50% of total oil production in China.

At Fushun, oil shale overlies a coal bed which is being mined. Because the oil shale must be stripped in order to reach the coal, it is economical to retort the shale even though it is of low grade. Fischer Assay yield is about 55% oil, on average.

Currently, only 40 retorts are operating, each retort processing 200 tons of oil shale per day. Other retorts have been shut down because of site problems not related to the operation of the retorts. Shale oil production is on the order of 100,000 tons per year.

Direct combustion of oil shale fines in an ebullated bed boiler has been tested at Fushun Refinery No. 2.

Shale oil is currently being used only as a boiler fuel, but a new scheme for upgrading Fushun shale oil has been studied. In the proposed scheme, shale oil is first treated by exhaustive delayed coking to make light fractions which are then treated successively with dilute alkali and sulfuric acid to recover the acidic and basic non-hydrocarbon components as fine chemicals. The remaining hydrocarbons, containing about 0.4 percent N can then be readily hydrotreated to obtain naphtha, jet fuel and light diesel fuel. This scheme is said to be profitable and can be conveniently coupled into an existing petroleum refinery.

ISRAELI RETORTING DEVELOPMENT – (See PAMA Oil Shale-Fired Power Plant Project)

JORDAN OIL SHALE PROJECT – Natural Resources Authority of Jordan (S-110)

Jordan's oil shale deposits are the country's major hydrocarbon resource. Near-surface deposits of Cretaceous oil shale in the Iribid, Karak, and Ma'an districts contain an estimated 44 million barrels of oil equivalent.

In 1986, a cooperative project with Romania was initiated to investigate the development of a direct-combustion oil-shale-fired power plant. Jordan has also investigated jointly with China the applicability of a Fushun-type plant to process 200 tons per day of oil shale. A test shipment of 1,200 tons of Jordanian shale was sent to China for retort testing. Large-scale combustion tests have been carried out at Kloeckner in West Germany and in New Brunswick, Canada.

A consortium of Lurgi and Kloeckner completed in 1988 a study concerning a 50,000 barrel per day shale oil plant operating on El Lajjun oil shale. Pilot plant retorting tests were performed in Lurgi's LR pilot plant in Frankfurt, Germany.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

The final results showed a required sales revenue of $19.10 per barrel in order to generate an internal rate of return on total investment of 10 percent. The mean value of the petroleum products ex El Lajjun complex was calculated to be $21.40 per barrel. At that time a world oil price of $15.60 per barrel was needed to meet an internal rate of return on total investment of 10 percent.

In 1988, the Natural Resources Authority announced that it was postponing for 5 years the consideration of any commercial oil shale project.

KIVITER PROCESS - Estonian Republic (S-120)

The majority of oil shale (kukersite) found in Estonia is used for power generation. However, 2.0 to 2.2 million tons are retorted to produce shale oil and gas. The Kiviter process, continuous operating vertical retorts with countercurrent flow of heat carrier gas and traditionally referred to as generators, is predominantly used in commercial operation. The retorts have been automated, and have throughput rates of 200 to 220 tons of shale per day. Retorting is performed in a single retorting (semi-coking) chamber. In the generators, low temperature carbonization of kukersite yields 75 to 80 percent of Fischer assay oil. The yield of low calorific gas (3,350 to 4,200 KJ/cubic meters) is 450 to 500 cubic meters per ton of shale.

To meet the needs of re-equipping of the oil shale processing industry, a new generator was developed. The first 1,000 ton-per-day (TPD) generator of this type was constructed at Kohila-Jarve, Estonia and placed in operation in 1981. The new retort employs the concept of countercurrent flow of heat carrier gas through the fuel bed, with additional heat added to the semi-coking chamber. A portion of the heat carrier is prepared by burning recycle gas. Raw shale is fed through a charging device into two semi-coking chambers arranged in the upper part of the retort. The use of two parallel chambers provides a larger retorting zone without increasing the thickness of the bed. Additional heating or gasification occurs in the mid-part of the retort by introducing hot gases or an oxidizing agent through side combustion chambers equipped with gas burners and recycle gas inlets to control the temperature. Near the bottom of the retort is a cooling zone where the spent shale is cooled by recycle gas and removed from the retort. The outside diameter of the retort is 9.6 meters, and its height is 21 meters. The operation of the 1,000 ton per day generator revealed a problem of carry-over of finely divided solid particles with oil vapors (about 8 to 10 kilograms per ton of shale).

The experience of the 1,000 TPD unit was taken into consideration to design two new units. In January, 1987, two new 1,000 TPD retorts were put in operation also at Kohila-Jarve. Alongside these units, a new battery of four 1,500 TPD retorts, with a new circular chamber design, is under construction. Oil yield of 85% of Fischer Assay is expected. The construction of an installation comprising four 1,500 ton per day prototype generators with a circular semicoking chamber started at Kohila-Jarve in 1988. At present, however, the construction has been suspended due to investment problems.

Oil from kukersite has a high content of oxygen compounds, mostly resorcinol series phenols. Over 50 shale oil products (predominantly non-fuel) are currently produced. These products are more economically attractive than traditional fuel oil. The low calorific gas produced as byproduct in the gas generators has a hydrogen sulfide content of 8 to 10 grams per cubic meter. After desulfurization, it is utilized as a local fuel for the production of thermal and electric power.

Pulverized oil shale ash is also finding extensive use in the fertilizer and cement industries.

Project Cost: Not disclosed

MAOMING COMMERCIAL SHALE OIL PLANT - Maoming Petroleum Industrial Corporation, SINOPEC, Maoming, China (S-130)

Construction of the Maoming processing center began in 1955. Oil shale is mined by open pit means with power-driven shovels, and electric locomotives and dump-cars. Current mining rates are 3.5 million tons of oil shale per year. Approximately one-half is suitable for retort feed. The Fischer Assay of the oil shale averages 6.5% oil yield.

Two types of retort are used: a cylindrical retort with a gasification section, and a rectangular gas combustion retort. Oil shale throughput is 150 and 185 tons per day per retort, respectively. The present facility consists of two batteries containing a total of 48 rectangular gas combustion retorts and two batteries with a total of 64 cylindrical retorts.

Production at Maoming has been approximately 100,000 tons of shale oil per year. Although the crude shale oil was formerly refined, it is now sold directly as fuel oil. The shale ash is also used in making cement and building blocks.

A 50 megawatt power plant burning oil shale fines in 3 fluidized bed boilers has been planned and detailed compositional studies of the Maoming shale oil have been completed. These studies can be used to improve the utilization of shale oil in the chemical industry.

MOBIL PARACHUTE SHALE OIL PROJECT - Mobil Oil Corporation (S-140)

Mobil has indefinitely deferred development plans for its shale property located on 10,000 acres five miles north of Parachute. The United States Bureau of Land Management completed the Environmental Impact Statement for the project in 1986.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

MOROCCO OIL SHALE PROJECT -- ONAREP, Royal Dutch/Shell (S-150)

During 1975 a drilling and mining survey revealed 13 oil shale deposits in Morocco, including three major deposits at Timandit, Tangier, and Tarfaya from which the name 13 for the Moroccan oil shale retorting process was derived.

In February 1982, the Moroccan Government concluded a $4.5 billion, three phase joint venture contract with Royal Dutch/Shell for the development of the Tarfaya deposit including a $4.0 billion, 70,000 barrels per day plant. However, the project faced constraints of low oil prices and the relatively low grade of oil shale.

Construction of a pilot plant at Timandit was completed with funding from the World Bank in 1984. During the first quarter of 1985, the plant went through a successful shakedown test, followed by a preliminary single retorting test. The preliminary test produced over 25 barrels of shale oil and proved the fundamental process feasibility of the T3 process. More than a dozen single retort tests were conducted to prove the process feasibility as well as to optimize the process conditions. The pilot plant utilizes the T3 process developed jointly by Science Applications, Inc., and the Office National de Recherche et d'Exploitation Petrolieres (ONAREP) of Morocco. The T3 process consists of a semi-continuous dual retorting system in which heat from one vessel that is being cooled provides a portion of the energy that is required to retort the shale in the second vessel. The pilot plant has a 100 tons of raw shale per day capacity using 17 gallons per ton shales. The design of a demonstration plant, which will have an initial output of 280 barrels per day, rising to 7,800 barrels per day when full scale commercial production begins, has been deferred. A commercial scale mine development study at Timandit was conducted by Morrison-Knudsen.

The T3 process will be used in conjunction with other continuous processes in Morocco. In 1981/1982, Science Applications, Inc., conducted for ONAREP extensive process option studies based on all major processes available in the United States and abroad and made a recommendation in several categories based on the results from the economic analysis. An oil-shale laboratory including a laboratory scale retort, computer process model and computer process control, has been established in Rabat with assistance from Science Applications, Inc.

The project, inactive for some time, began being reconsidered in 1990 by the equal partners. The viability of a 50,000 barrel per day plant that would process 60 million tonnes of shale is under examination. ONAREP expects the cost of development to be around $24-25 a barrel.

Project Cost: $2.5 billion (estimated)

OCCIDENTAL MIS PROJECT -- Occidental Oil Shale, Inc. (S-20)

Federal Oil Shale Lease Tract C-b, located in Rio Blanco County in the Piceance Creek Basin of northwestern Colorado, is managed by Occidental Oil Shale, Inc. A modified detailed development plan for a 57,000 barrels per day modified in situ plant was submitted in March 1977 and subsequently approved in April 1977. The EPA issued a conditional Prevention of Significant Deterioration (PSD) permit in December 1977 which was amended in 1983.

Project reassessment was announced in December 1981 in view of increased construction costs, reduced oil prices, and high interest rates. The project sponsors applied to the United States Synthetic Fuels Corporation (SFC) under the third solicitation in January 1983 and the project was advanced into Phase II negotiations for financial assistance. On July 28, 1983 the SFC announced it had signed a letter of intent to provide up to $2.19 billion in loan and price guarantees to the project. However, Congress abolished the SFC on December 19, 1985 before any assistance could be awarded to the project.

Three headframes—two concrete and one steel—have been erected. Four new structures were completed in 1982: control room, east and west airlocks, and mechanical/electrical rooms. The power substation on-tract became operational in 1982. The ventilation/escape, service, and production shafts were completed in Fall 1983. An interim monitoring program was approved in July 1982 to reflect the reduced level of activity.

Water management in 1984 was achieved via direct discharge from on-tract holding ponds under the NPDES permit. Environmental monitoring has continued since completion of the two-year baseline period (1974-1976).

On April 1, 1987, the Bureau of Land Management, United States Department of the Interior, granted Cathedral Bluffs Shale Oil Company a suspension of operation and production for a minimum of five years. Meanwhile, pumping of the mine inflow water continued in order to keep the shaft from being flooded.

Although Congress appropriated $8 million in fiscal year 1991, Occidental declined to proceed with the $225 million "proof-of-concept" modified in situ (MIS) demonstration project to be located on the C-b tract. In January 1991 Occidental announced its intention to shelve the demonstration project in an effort to reduce company debt. The announcement came only a month after the death of Oxy chairman, Armand Hammer, a long-time supporter of oil shale.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

The project was to be a 1,200 barrel per day demonstration of the modified in situ (MIS) retorting process. Estimates indicate that there are more than 4.5 billion barrels of recoverable oil at the site. Also included in the project were plans for a 33 megawatt oil shale fired power plant to be built at the C-b tract. Such a power plant would be the largest of its kind in the world.

At the end of the demonstration period, Occidental had hoped to bring the plant up to full scale commercial production of 2,500 barrels of oil per day.

Project Cost: $225 million for demonstration

PAMA OIL SHALE-FIRED POWER PLANT PROJECT - PAMA (Energy Resources Development) Inc. (S-270)

PAMA, an organization founded by several major Israeli corporations with the support of the government, has completed extensive studies, lasting several years, which show that the production of power by direct combustion of oil shale is technically feasible. Furthermore, the production of power still appears economically viable, despite the uncertainties regarding the economics of production of oil from shale.

PAMA has, therefore begun a direct shale-fired demonstration program. A demo plant has been built that is in fact a commercial plant, co-producing electricity to the grid and low pressure steam for process application at a factory adjacent to the Rotem oil shale deposit. The oil-shale-fired boiler, supplied by Ahlstrom, Finland, is based on a circulating fluid bed technology.

The 41 megawatt plant is a cogeneration unit that delivers 50 tons per hour of steam at high pressure. Low-pressure steam is sold to process application in a chemical plant, and electricity produced in a back-pressure turbine is sold to the grid. Commissioning was begun in August 1989 and oil shale firing began in October. Process steam sales began in November 1989 and electricity production started in February, 1990.

The unit is viewed as a demonstration project where tests will be performed over a three year period. During this time, the optimum operating parameters will be determined for scale-up to larger units.

PAMA and Israel Electric (the sole utility of Israel) have also embarked on a project to build a full scale oil shale-fired commercial power plant, which will consist of eight 120-megawatt units. The first unit is scheduled to go into operation in 1996.

Project Cost: $30 million for combustion demonstration plant

PARACHUTE CREEK SHALE OIL PROJECT - UNOCAL Corporation (S-160)

In 1920 Unocal began acquiring oil shale properties in the Parachute Creek area of Garfield County, Colorado. The 49,000 acres of oil shale lands Unocal owns contain over three billion barrels of recoverable oil in the high-yield Mahogany Zone alone. Since the early 1940s, Unocal research scientists and engineers have conducted a wide variety of laboratory and field studies for developing feasible methods of producing usable oils from shale. In the 1940s, Unocal operated a small 50 ton per day pilot retort at its Los Angeles, California refinery. From 1955 to 1958, Unocal built and operated an upflow retort at the Parachute site, processing up to 1,200 tons of ore per day and producing up to 800 barrels of shale oil per day.

Unocal began the permitting process for its Phase I 10,000 barrel per day project in March 1978. All federal, state, and local permits were received by early 1981. Necessary road work began in the Fall 1980. Construction of a 12,500 ton per day mine began in January 1981, and construction of the retort started in late 1981. Concurrently, work proceeded on a 10,000 barrels per day upgrading facility, which would convert the raw shale oil to a high quality syncrude.

Construction concluded and the operations group assumed control of the project in the Fall 1983. After several years of test operations and resulting modifications, Unocal began shipping upgraded syncrude on December 23, 1986.

In July 1981, the company was awarded a contract under a United States Department of Energy (DOE) program designed to encourage commercial oil shale production in the United States. The price was to be the market price or a contract floor price. If the market price is below the DOE contract floor price, indexed for inflation, Unocal would receive a payment from DOE to equal the difference. The total amount of DOE price supports Unocal could receive was $400 million. Unocal began billing the U.S. Treasury Department in January, 1987 under its Phase I support contract.

In a 1985 amendment to the DOE Phase I contract, Unocal agreed to explore using fluidized bed combustion (FBC) technology at its shale plant. In June 1987, Unocal informed the U.S. Treasury Department that it would not proceed with the FBC technology. A key reason for the decision, the company said, was the unexpectedly high cost of the FBC facility.

In 1989, a new crusher system was installed which produces a smaller and more uniform particle size to the retort. Also, retort operations were modified and the retorting temperature increased. As a result, production in November and December reached approximately 7,000 barrels per day.

SYNTHETIC FUELS REPORT, JUNE 1992

2-37
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

At year-end 1990, Unocal had shipped over 4.5 million barrels of syncrude from its Parachute Creek Project. Unocal announced the shale project booked its first profitable quarter for the first calendar quarter of 1990. Positive cash flow had been achieved previously for select monthly periods; however, this quarter's profit was the first sustained period of profitability. Cost cutting efforts further lowered the break-even point on operating costs approximately 20 percent.

In 1990, the United States Department of Treasury found no significant environmental, health or safety impacts related to the operations of Parachute Creek. Monitoring will continue through 1992.

On March 26, 1991, Unocal announced that production operations at the facility would be suspended because of failure to consistently reach the financial break-even point. Production ended June 1, 1991 and the project was laid up for an indefinite period.

Unocal has offered to sell the Parachute facility to the U.S. Department of Energy (DOE) as a research test facility but has received no commitment from DOE to date.

Colorado Clean Fuels Company has obtained approval from Garfield County Commissioners to refit Unocal's oil shale plant for fuel processing. The plant will process natural gas into four products: methanol, smokeless diesel, naphtha and wax. The county commissioners approved the request after a public hearing on the matter.

The anticipated project development calls for July 1992 construction, employing 40 to 110 workers, followed by operation startup employing 24 people. If the company obtains state and federal permits as well, the plant will be operational in August 1993.

The company plans to produce 4,200 barrels of methanol per day from natural gas. In addition, 138 barrels per day of diesel fuel, 51 barrels per day of naphtha, and 1,111 barrels per day of wax will be produced.

Project Cost: Phase I - Approximately $1.2 billion

PETROSIX – Petrobras (Petroleo Brasileiro, S.A.) (S-170)

A 6 foot inside diameter retort, called the demonstration plant, has been in continuous operation since 1984. The plant is used for optimization of the Petrosix technology. Oil shales from other mines can be processed in this plant to obtain data for the basic design of new commercial plants.

A Petrosix pilot plant, having an 8 inch inside diameter retort, has been in operation since 1982. The plant is used for oil shale characterization and retorting tests and developing data for economic evaluation of new commercial plants.

An entrained bed pilot plant has been in operation since 1980. It is used to develop a process for the oil shale fines. The plant uses a 6 inch inside diameter pipe (reactor) externally heated. Studies at the pilot scale have been concluded.

A spouted bed pilot plant having a 12-inch diameter reactor, has been in operation since January, 1988. It processes oil shale fines coarser than that used in the entrained bed reactor. Studies at the pilot scale have been concluded.

A multistaged fluidized bed pilot plant having an 8x8 inch square section was operated at Centec. Studies at this scale have been concluded.

A circulating fluidized bed pilot scale boiler was started up in July, 1988. The combustor will be tested on both spent shale and oil shale fines to produce process steam for the Petrosix commercial plants.

A nominal 2,200 tons per day Petrosix semi-works retort, 18 foot inside diameter, is located near Sao Mateus do Sul, Parana, Brazil. The plant has been operated successfully near design capacity in a series of tests since 1972. A United States patent has been obtained on the process. This plant, operating on a small commercial basis since 1981, produced 850 barrels per day of crude oil, 40 tons per day of fuel gas, and 18 tons per day of sulfur in 1990. The operating factor since 1981 until present has been 93 percent.

As of December 31, 1991, the plant records were as follows:

<p>| | |</p>
<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>Operations time, hrs</td>
<td>126,400</td>
</tr>
<tr>
<td>Oil Produced, Bbl</td>
<td>3,360,000</td>
</tr>
<tr>
<td>Processed Oil Shale, tons</td>
<td>7,070,000</td>
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<tr>
<td>Sulfur Produced, tons</td>
<td>568,130</td>
</tr>
<tr>
<td>High BTU Gas, tons</td>
<td>121,600</td>
</tr>
</tbody>
</table>

A 36-foot inside diameter retort, called the industrial module, has been constructed at Sao Mateus do Sul. Startup began in January, 1992. Total investment was US$93 million with an annual operating cost estimated to be US$39 million. With the sale of gas to Industria Ceramica do Parana (INCEPA) and anticipated revenue from products, the rate of return on the overall project is estimated to be about 13 percent.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

In 1992, the Sao Mateus do Sul project is producing at 70 percent of the full-scale capacity. Total daily production is expected to reach 4,000 barrels of shale oil (at a cost of $22.50 per barrel), 140 metric tons of fuel as, 50 tons of liquefied petroleum gas and 100 tons of sulfur.

With the 36-foot (11-meter) diameter commercial plant, the daily production of the two plants will be:

<table>
<thead>
<tr>
<th>Product</th>
<th>Quantity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale Oil</td>
<td>3,870 Bbl</td>
</tr>
<tr>
<td>Processed Shale</td>
<td>7,800 tonnes</td>
</tr>
<tr>
<td>LPG</td>
<td>50 tonnes</td>
</tr>
<tr>
<td>High BTU Gas</td>
<td>132 tonnes</td>
</tr>
<tr>
<td>Sulfur</td>
<td>98 tonnes</td>
</tr>
</tbody>
</table>

Some 150 hectares of the mined area has been rehabilitated since 1977. Rehabilitation comprises reforestation, revegetation with local plants and reintegration of wild local animals, bringing back the local conditions for farming and recreational purposes.

Current shale oil production is sent by truck to a refinery 150 kilometers from the plant and is stabilized through the FCC unit in a mixture with heavy gas oil.

Sulfur production is sold directly to clients from local paper mill industries.

Project Installed Costs: $93 (US) Million

RAMEX OIL SHALE GASIFICATION PROCESS—Greenway Corporation and Ramex Synfuels International, Inc. (S-180)

On May 6, 1985 Ramex began construction of a pilot plant near Rock Springs, Wyoming. The pilot plant consisted of two specially designed burners to burn continuously in an underground oil shale bed at a depth of 70 feet. These burners produce an industry quality gas (greater than 800 BTUs per standard cubic foot).

In November 1986, Ramex announced that Greenway Corporation had become the controlling shareholder in the company.

On November 24, 1987, Ramex announced the completion of the Rock Springs pilot project. The formation was heated to approximately 1200 degrees F creating a high-BTU gas with little or no liquid condensate. The wells sustained 75 Mcf a day, for a period of 3 months, then were shut down to evaluate the heaters and the metals used in the manufacturing of the heaters. The test results indicated a 5 year life in a 10 foot section of the shale with a product gas of 800 BTU, or higher, per standard cubic foot.

Ramex also announced in November 1987 the start of a commercial production program in the devonian shale in the eastern states of Kentucky and Tennessee. In April 1988, however, Ramex moved the project to Indiana. A total of 7 wells were drilled. Gas tests resulted in ratings of 1,034 and 968 8Th. Two production volume tests showed 14,000 and 24,000 cubic feet per day.

In late July, 1988 a letter agreement was signed between Tri-Gas Technology, Inc., the licensee of the Ramex process in Indiana, and J. M. Slaughter Oil Company of Ft. Worth, Texas to provide funding for drilling a minimum of 20 gas wells, using the Ramex oil shale gasification process, on the leases near Henryville, Indiana. Arrangements were made with Midwest Natural Gas to hook up the Ramex gas production to the Midwest Pipeline near Henryville.

As of May, 1989 Ramex had been unsuccessful in sustaining long-term burns. They therefore redesigned the burner and built a much larger model (600,000 BTU per hour vs 40,000 BTU per hour) for installation at the Henryville site. In November, 1989 Ramex completed its field test of the Devonian Shales in Indiana. The test showed a gas analysis of 47% hydrogen, 30% methane and little or no sulfur. Ramex contracted with a major research firm to complete the design and material selection of its commercial burners which they say are 40 to 50 percent more fuel efficient than most similar industrial units and also to develop flow measurement equipment for the project. Ramex received a patent on its process on May 29, 1990.

In 1990, Ramex also began investigating potential applications in Israel.

Ramex contracted with the Institute of Gas Technology in 1990 for controlled testing of its in situ process because the company's field tests of the process in wells in Indiana have been thwarted by ground water incursion problems. Questions that still need to be answered before the Ramex process can be commercialized are:

- How fast does the heat front move through the shale?
- How far will the reaction go from the heat source and how much heat is necessary on an incremental basis to keep the reaction zone moving outward from the source of heat?
- What is the exact chemical composition of the gas that is produced from the process over a period of time and does the composition change with varying amounts of heat and if so, what is the ideal amount of heat to produce the most desirable chemical composition of gas?

SYNTHETIC FUELS REPORT, JUNE 1992
COMMERCIAL PROJECTS (Continued)

Once these questions are answered, the company will be able to calculate the actual cost per unit of gas production.

Project Cost: Approximately $1 million for the pilot tests.

RIO BLANCO OIL SHALE PROJECT -- Rio Blanco Oil Shale Company (wholly owned by Amoco Corporation) (S-190)

The proposed project is on federal Tract C-a in Piceance Creek Basin, Colorado. A bonus bid of $210.3 million was submitted to acquire rights to the tract which was leased in March 1974. A four-year modified in situ (MIS) demonstration program was completed at the end of 1981. The program burned two successful retorts. The first retort was 30 feet by 30 feet by 166 feet high and produced 1,907 barrels of shale oil. It burned between October and late December 1980. The second retort was 60 feet by 60 feet by 400 feet high and produced 24,790 barrels while burning from June through most of December 1981. Open pit mining-surface retorting development is still preferred, however, because of much greater resource recovery of 5 versus 2 billion barrels over the life of the project. Rio Blanco, however, could not develop the tract efficiently in this manner without additional federal land for disposal purposes and siting of processing facilities, so in August 1982, the company temporarily suspended operations on its federal tract after receiving a 5 year lease suspension from the United States Department of Interior. In August 1987, the suspension was renewed.

Federal legislation was enacted to allow procurement of off-tract land that is necessary if the lease is to be developed by surface mining. An application for this land was submitted to the Department of Interior in 1983. Based on the decision of the director of the Colorado Bureau of Land Management, an environmental impact statement for the proposed lease for 84 Mesa has been prepared by the Bureau of Land Management. However, a Record of Decision was never issued due to a suit filed by the National Wildlife Federation.

Rio Blanco submitted a MIS retort abandonment plan to the Department of Interior in Fall 1983. Partial approval for the abandonment plan was received in Spring 1984. The mine and retort were flooded but were pumped out in May 1985 and June 1986 in accordance with plans approved by the Department of the Interior.

Rio Blanco operated a $29 million, 1 to 5 TPD Lurgi pilot plant at Gulf's Research Center in Harmarville, Pennsylvania until late 1984 when it was shut down. This $29 million represents the capital and estimated operating cost for up to 5 years of operation. On January 31, 1986 Amoco acquired Chevron's 50 percent interest in the Rio Blanco Oil Shale Company, thus giving Amoco a 100 percent interest in the project.

Project Cost: Four-year process development program cost $132 million
No cost estimate available for commercial facility.

RUNDLE PROJECT -- Central Pacific Minerals/Southern Pacific Petroleum (50 percent) and Esso Exploration and Production Australia (50 percent) (S-200)

The Rundle Oil Shale deposit is located near Gladstone in Queensland, Australia. In April 1981, construction of a multi-module commercial scale facility was shelved due to economic and technical uncertainties.

Under a new agreement between the venturers, which became effective in February 1982, Esso agreed to spend A$30 million on an initial 3 year work program that would resolve technical difficulties to allow a more precise evaluation of the economics of development. During the work program the Dravo, Lurgi, Tosco, and Exxon retorting processes were studied and tested. Geological and environmental baseline studies were carried out to characterize resource and environmental parameters. Mine planning and materials handling methods were studied for selected plant capacities. Results of the study were announced in September 1984. The first stage of the project which would produce 5.2 million barrels per year from 25,000 tons per day of shale feed was estimated to cost $645 million (US). The total project (27 million barrels per year from 125,000 tons per day of shale feed) was estimated to cost $2.65 billion (US).

In October 1984 SPP/CPM and Esso announced discussions about amendments to the Rundle Joint Venture Agreement signed in 1982. Those discussions were completed by March 1985. Revisions to the Joint Venture Agreement provide for:

Payment by Esso to SPP/CPM of A$30 million in 1985 and A$12.5 in 1987.
Each partner to have a 50 percent interest in the project.

Continuation of a Work Program to progress development of the resource.

Esso funding all work program expenditures for a maximum of 10 years, and possible funding of SPP/CPM's share of subsequent development expenditures. If Esso provides disproportionate funding, it would be entitled to additional offtake to cover that funding.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMERCIAL PROJECTS (Continued)

The project is continuing at a low level with work in 1992 focusing on environmental land and resource management and further shale upgrading and processing studies.

Project Cost: US$2.65 billion total estimated

SIIC - 3000 RETORTING PROCESS - Estonian Republic (S-230)

The SHC-3000 process, otherwise known as the Galoter retort, is a rotary kiln type retort which can accept oil shale fines.

Processing of the lukernite shale in SHC-3000 retorts makes it possible to build units of large scale, to process shale particle sizes of 25 millimeters and less including shale dust, to produce liquid fuels for large thermal electric power stations, to improve operating conditions at the shale-burning electric power stations, to increase (thermal) efficiency up to 86-87 percent, to improve sulfur removal from shale fuel, to produce sulfur and other sulfur containing products (such as thiophene) by utilizing hydrogen sulfide of the semicoke gas, and to extract valuable phenols from the shale oil water. Overall the air pollution (compared to direct oil shale combustion) decreases.

The two SHC-3000 units built in 1980 at the Estonian Power Plant, Narva, Estonia, with a capacity of 3,000 tons of shale per day are among the largest in the world and unique in their technological principles. However, these units have been slow in reaching full design productivity.

A redesign and reconstruction of particular parts of the units was done in 1984 to improve the process of production and to increase the period of continuous operation.

As a result of these changes, the functioning of the SHC-3000 improved dramatically in 1984 in comparison with the period of 1980-1983. For instance, the total amount of shale processed in the period 1980-1983 was almost the same as for only 1984, i.e. 79,100 tons versus 80,100 in 1984. The total shale oil production for the period 1980-83 was 10,500 tons and approximately the same amount was produced only in 1984. The average output of shale oil per run increased from 27 tons in 1980 to 970 tons in 1984. The output of electric energy for Estonia-Energo continued constant in 1983 and 1984, by burning part of the shale oil in the boilers of Estonia GRES.

By the end of 1984, 159,200 tons of shale was processed and 20,000 tons of shale oil was produced at SHC-3000.

In 1985, the third test of the reconstructed boiler TP-101 was carried out by using the shale oil produced at the SHC-3000. The improvement of the working characteristics of SHC-3000 has continued.

LO VGNIPH (the name of the Research Institute) has designed for Estonia an electric power station that would use shale oil and produce 2,600 megawatts. A comparison of its technical-economical characteristics with the corresponding ones of the 2,500 megawatts power station with direct burning of raw shales was made. It was found that the station on shale oil would be more economical than the station with direct burning of shale.

In 1990, 374,000 tons of shale was used for processing and 43,600 tons of shale oil was produced. In 1991, 205,500 tons of shale were used to produce 24,000 tons of oil. At present, shale with an organic content of 28 percent is used for processing, the oil yield being about 12 percent per shale. The oil obtained contains 14 to 15 percent of gasoline fraction. Export of the oil produced is growing steadily—from 8,900 tons in 1990 to 24,300 tons in 1991.

By the end of 1991, 1,833,700 tons of shale was processed at SHC-3000 and 220,000 tons of oil had been produced.

STUART OIL SHALE PROJECT – Southern Pacific Petroleum NL and Central Pacific Minerals NL (S-210)

In 1985 Southern Pacific Petroleum NL and Central Pacific Minerals NL (SPP/CPM) studied the potential for developing a demonstration retort based upon mining the Kerosene Creek Member of the Stuart oil shale deposit in Queensland, Australia.

This study utilized data from a number of previous studies and evaluated different retorting processes. It showed potential economic advantages for utilizing the Taciuk Process developed by Umatac and AOSTRA (Alberta Oil Sands Technology and Research Authority) of Alberta, Canada. Batch studies were carried out in 1985, followed by engineering design work and estimates later the same year. As a consequence of these promising studies a second phase of batch testing at a larger scale was carried out in 1986. A series of 68 pyrolysis tests were carried out using a small batch unit. A number of these tests achieved oil yields of 105 percent of Modified Fischer Assay.

As a result of the Phase 2 batch tests, SPP updated their cost estimates and reassessed the feasibility of the Taciuk Processor for demonstration plant use. The economics continued to favor this process so the decision was made to proceed with tests in the 100 tonne per day pilot plant in 1987. A sample of 2,000 tonnes of dried Stuart oil shale was prepared in late 1986 and early 1987. The pilot plant program was carried out between June and October 1987.

SYNTHETIC FUELS REPORT, JUNE 1992

2-41
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

During the last quarter of 1987, SPP carried out a short drilling program of 10 holes at the Stuart deposit in order to increase information on the high grade Kerosene Creek member. This is a very high grade seam (134 liters per tonne) with 150 million barrels of reserves.

SPP/CPM engaged two engineering firms to make independent, detailed studies of the shale oil project. The purpose of the studies is to provide potential financial backers with verifiable information on which to base technical judgment of the project. These studies were completed in early 1991. Both groups confirmed SPP/CPM's own numbers and endorsed the AOSTRA Taciuk Processor as the most effective retort for Queensland oil shale.

The overall SPP development plan includes three stages, commencing with a low capital cost, semi-commercial plant at 6,000 tonnes per day of high grade shale feed producing 4,250 barrels per day of oil. SPP/CPM have received proposals from two engineering firms for the construction of the 6,000 tonne per day plant. Once the retorting technology is proven the second stage plant at 25,000 tons per day of shale producing 14,000 barrels per day of syncrude from an intermediate grade will be constructed. Stage three is a replication step with five 25,000 ton per day units producing 60,000 barrels per day of syncrude from average grade shale, or approximately 15 percent of the projected Australian oil import requirement in the year 2000.

According to SPP, the estimated cost is US$110 million for the first stage demonstration plant to be located near Gladstone, including services connection and product storage. At 1990 prices for low sulfur fuel oil in Australia, it is said that operation of the demonstration plant will at least break even and possibly earn as much as 15 percent DCFROI. Stage 1 of the project will benefit from a recently announced tax exemption which will apply to about 40 percent of the plant's output. Refined products will be exempt from excise taxes amounting to US$0.2075 per liter for a total savings to the project of US$190 million over a 10-year period. The exemption was guaranteed until the year 2005.

However, the federal opposition party in Australia has announced that it will eliminate all excise on gasoline if elected to govern. SPP/CPM have held discussions with the opposition party to ensure preservation of the promised arrangements, but have not received any such assurance. Therefore, the companies are now assessing appropriate adjustments to the Stage 1 financing plans in case the opposition party does come to power.

SPP/CPM recently announced that they have received a definitive proposal for construction of Stage 1 of the project. The companies will now begin discussions with potential investors. After a year of operation it is expected that sufficient data and operating experience will have been gathered to scale up the technology to full commercial size (25,000 tonnes per day).

The first commercial module could be in production by the middle of 1994.

Project Cost: For commercial demonstration module A$110 million

YAAMBA PROJECT — Yaamba Joint Venture [Beloba Pty. Ltd. (10%), Central Pacific Minerals N.L. (3.3%), Southern Pacific Petroleum N.L. (3.3%), Shell Company of Australia Limited (41.66%), and Peabody Australia Pty. Ltd. (41.66%)] (S-240)

The Yaamba Oil Shale Deposit occurs in the Yaamba Basin which occupies an area of about 57 square kilometers adjacent to the small township of Yaamba located 30 kilometers (19 miles) north-northwest of the city of Rockhampton, Australia.

Oil shale was discovered in the Yaamba Basin in 1978 during the early stages of a regional search for oil shale in buried Tertiary basins northwest of Rockhampton. Exploration since that time has outlined a shale oil resource estimated at more than 4.8 billion barrels in situ extending over an area of 32 square kilometers within the basin.

The oil shales which have a combined aggregate thickness of over 300 meters in places occur in 12 main seams extending through the lower half of a Tertiary sequence which is up to 800 meters thick toward the center of the basin. The oil shales subcrop along the southern and southwestern margins of the basin and dip gently basinward. Several seams of lignite occur in the upper part of the Tertiary sequence above the main oil shale sequences. The Tertiary sediments are covered by approximately 40 meters of unconsolidated sands, gravels, and clays.

During 1988, activities in the field included the extraction of samples for small scale testing and the drilling of four holes for further resource delineation.

In December, 1988 Shell Australia purchased a part interest in the project. Peabody Australia manages the Joint Venture which holds two "Authorities to Prospect" for oil shale in an area of approximately 1,080 square kilometers in the Yaamba and Broad Sound regions northwest of Rockhampton. In addition to the Yaamba Deposit, the "Authorities to Prospect" cover a second prospective oil shale deposit in the Herbert Creek Basin approximately 70 kilometers northwest of Yaamba. Drilling in the Herbert Creek Basin is in the exploratory stage.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

A Phase I feasibility study, which focused on mining, waste disposal, water management, infrastructure planning, and preliminary ore characterization of the Yaamba oil shale resource, has been completed. Environmental baseline investigations were carried out concurrently with this study. Further investigations aimed at determining methods for maximum utilization of the total energy resource of the Yaamba Basin and optimization of all other aspects of the mining operation, and collection of additional data on the existing environment were undertaken.

During 1990, exploration and development studies at the Yaamba and Herbert Creek deposits continued. A program of three holes (644 meters) was undertaken in the Block Creek area at the southeast of the Herbert Creek deposit.

Project Cost: Not disclosed

R&D PROJECTS

LLNL HOT RECYCLED-SOLIDS (HRS) RETORT - Lawrence Livermore National Laboratory, U. S. Department of Energy (S-300)

Lawrence Livermore National Laboratory (LLNL) has, for over the last 5 years, been studying hot-solid recycle retorting in the laboratory and in a 1 tonne per day pilot facility and have developed the LLNL Hot Recycled-Solids Retort (HRS) process as a generic second generation oil shale retorting system. Much progress has been made in understanding the basic chemistry and physics of retorting processes and LLNL believes they are ready to proceed to answer important questions to scale the process to commercial sizes. LLNL hopes to conduct field pilot plant tests at 100 and 1,000 tonnes per day at a mine site in western Colorado.

In this process, raw shale is rapidly heated in a gravity bed pyrolyzer to produce oil vapor and gas. Residual carbon (char), which remains on the spent shale after oil extraction, is burned in a fluid bed combustor, providing heat for the entire process. The heat is transferred from the combustion process to the retorting process by recycling the hot solid, which is mixed with the raw shale in a fluid bed prior to entering the pyrolyzer. The combined raw and burned shale (at a temperature near 500 degrees C) pass through a moving, packed-bed retort containing vents for quick removal and condensation of product vapors, minimizing losses caused by cracking (chemical breakdown to less valuable species). Leaving the retort, the solid is pneumatically lifted to the top of a cascading-bed burner, where the char is burned during impeded-gravity fall, which raises the temperature to nearly 650 degrees C. Below the cascading-bed burner is a final fluid bed burner, where a portion of the solid is discharged to a shale cooler for final disposal.

In 1990, LLNL upgraded the facility to process 4 tonnes per day of raw shale, working with the full particle size (0.25 inch). Key components of the process are being studied at this scale in an integrated facility with no moving parts using air actuated valves and a pneumatic transport, suitable for scaleup. In April 1991, the first full system run on the 4 tonne per day pilot plant was completed. Since that time, the retort has successfully operated on both lean and rich shale (22-38 gallons per ton) from western Colorado. LLNL plans to continue to operate the facility and continue conceptual design of the 100 tonne per day pilot-scale test facility. LLNL has joined with a consortium of industrial sponsors for its current operations in a 3 year contract to develop the HRS process.

The ultimate goal is a 1,000-tonne-per-day field pilot plant, followed by a commercially-sized demonstration module (12,000 tonnes per day) which could be constructed by private industry within a 10 year time frame. Each scale represents a factor of three increase in vessel diameter over the previous scale, which is not unreasonable for solid-handling equipment, according to LLNL.

Each company in the consortium will contribute $100,000 per year over the next 3 years. LLNL has negotiated successfully with Chevron, Conoco and Amoco, and hopes to interest other industrial partners which will form a Project Guidance Committee.

Project Cost:  
Phase I - $15 million  
Phase II - $35 million

NEW PARAHO ASPHALT FROM SHALE OIL PROJECT—New Paraho Corporation, Marathon Oil Company (S-310)

New Paraho Corporation is a wholly owned subsidiary of Energy Resources Technology Land, Inc. New Paraho Corporation plans to develop a commercial process for making shale-oil-modified road asphalt. Researchers at Western Research Institute (WRI) and elsewhere have discovered that certain types of chemical compounds present in shale oil cause a significant reduction in moisture damage and a potential reduction in binder embrittlement when added to asphalt. This is particularly true for shale oil produced by direct-heated retorting processes, such as Paraho’s.

In order to develop this potential market for shale oil modified asphalts, New Paraho has created an initial plan which is to result in (1) proven market performance of shale oil modified asphalt under actual climatic and road use conditions and (2) completion of a comprehensive commercial feasibility study and business plan as the basis for securing subsequent financing for a Colorado-based commercial production facility.

Project Cost:  
Phase I - $5 million

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

The cost of carrying out the initial market development phase of the commercial development plan was approximately $25 million, all of which was funded by Paraho. The major portion of the work conducted during this initial phase consisted of producing sufficient quantities of shale oil to accommodate the construction and evaluation of several test strips of shale oil-modified asphalt pavement. Mining of 3,900 tons of shale for these strips occurred in September 1987. The shale oil was produced in Paraho's pilot plant facilities, located near Rifle, Colorado in August, 1988. The retort was operated at mass velocities of 418 to 538 pounds per hour per square foot on 23 to 35 gallon per ton shale and achieved an average oil yield of 96.5 percent of Fischer Assay. In 1988, New Paraho installed a vacuum still at the pilot plant site to produce shale oil asphalt from crude shale oil.

Eight test strips have been constructed in Colorado, Utah and Wyoming. The test strips will now be evaluated over a period of several years, during which time Paraho will complete site selection, engineering and cost estimates, and financing plans for a commercial production facility. A new test strip was recently completed on I-20 east of Pecos, Texas. Construction is under way in Michigan for a test section of I-75 near Flint. Additional test strips will be built on I-70 east of Denver, Colorado and on US-59, northeast of Houston, Texas.

In late 1990, Marathon Oil Company joined New Paraho in their work on the asphalt binder which they are calling SOMAT (Shale Oil Modified Asphalt Technology).

Paraho has proposed a $180 million commercial scale plant capable of producing 3,380 barrels of crude oil per day, of which 2,700 barrels would be shale oil modifier (SOM) and 680 barrels would be light oil to be marketed to refineries.

An economic analysis has determined that SOM could be marketed at a price of $100 per barrel if tests show that SOMAT can affect at least a 10 percent improvement in pavement life. A feasibility study suggests that Paraho can expect a 30 percent rate of return on SOMAT production.

Paraho states that it has access to two different resource sites upon which the commercial production facility could be located: a site on the Mahogany Block in northwest Colorado; and the Paraho-Ute properties, located near Vernal, Utah. Of these options, the Mahogany site represents the most economically viable alternative and, accordingly, is the preliminary location of choice.

Approximately 1,500 acres of the Mahogany Block are still controlled by the Tell Ertl Family Trust and are available to New Paraho although the largest part of the original block was sold to Shell Oil Company. New Paraho also maintains control of approximately 3,400 acres of oil shale leases on state lands in Utah.

New Paraho has proposed a 7-month, $500,000 commercial evaluation program to assess the economic benefits of coprocessing used tires with oil shale. Initial experiments have demonstrated that retort operations can be sustained with used tires as 5 percent of the feedstock. The company plans to recommission its pilot plant at Rifle, Colorado to carry out farther retorting experiments.

Project Cost: $2,500,000. (New Paraho spent $100,000 in 1987, $1,100,000 in 1988 and $778,000 in 1989 on shale oil asphalt research.) $180 million estimated for commercial scale plant.

NORTHLAKE SHALE OIL PROCESSING PILOT--Northlake Industries, Inc. and Uintah Basin Minerals, Inc. (S-315)

Northlake Industries, Inc. of Naples, Utah and Uintah Basin Minerals, Inc. have signed contracts pledging over $100 million to process Uintah Basin, Utah oil shale deposits with their QVR process.

The Vernal District of the Bureau of Land Management (BLM) has issued a land use permit to Northlake allowing access to the mine service building and surface oil shale stockpiles at the White River Oil Shale Project. Northlake has put up $125,000 to extend the availability of the White River site until June 1992. The surface stockpiles will be used in a pilot plant located off the White River site in Naples. The BLM permit is short-term only and does not allow further surface mining.

QVR is an acronym for "quality enhancement and viscosity reduction." A modular upgrading unit for this process incorporates added temperature and fluid controls into the pilot plant allowing for scaleup to production models. Northlake's QVR unit has performed over 1,000 hours of upgrading service on 8 to 14°API gravity heavy crude oil and refinery bottoms. The unit will be modified to study oil shale kerogen.

The QVR process was developed by Northlake over the last 10 years and provides a profitable method of recovering light, sweet crude from shale oil, tar sands and coal. The proprietary technique turns heavy oil at 10 to 13°API gravity heavy crude oil and refinery bottoms. The unit will be modified to study oil shale kerogen.

The pilot plant stage will be operational by mid-fall of 1991.

If the development phase is successful, the company hopes to begin work on a 100,000 ton per day commercial production facility in 1994.
YUGOSLAVIA COMBINED UNDERGROUND COAL GASIFICATION AND MODIFIED IN SITU OIL SHALE RETORT —
United Nations (S-335)

Exceptional geological occurrence of oil shale and brown coal in the Aleksinac basin has allowed an underground coal gasification (UCG) combined with in situ oil shale retorting. Previous mining activities of Aleksinac brown coal and development of oil shale utilization (see Yugoslavia Modified In Situ Retort — S-330, Synthetic Fuels Report, December 1990) served as principal support in establishing a development project aimed towards application of a new process, i.e. combination of UCG and in situ oil shale retorting to be tested for feasibility in a pilot UCG modulus. The project is a joint scientific and technological undertaking performed by Yugoslavian and American staff.

The objective of the approach is to develop a program to exploit the total Aleksinac energy resources to provide regional power and heating for Aleksinac and surrounding area using UCG technology and combining it with modified in situ retorting of oil shale as the immediate roof of the brown coal seam.

The development objectives are also to recover energy from residual coal left after conventional coal mining and to develop UCG technology and modified in situ oil shale retorting for Yugoslavian resources in general.

Project Cost: US$725,000
## COMPLETED AND SUSPENDED PROJECTS

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>American Syncrude Indiana Project</td>
<td>American Syncrude Corp. Stone &amp; Webster Engineering</td>
<td>September 1987; page 2-53</td>
</tr>
<tr>
<td>Baytown Pilot Plant</td>
<td>Exxon Research and Engineering</td>
<td>September 1987; page 2-60</td>
</tr>
<tr>
<td>BX In Situ Oil Shale Project</td>
<td>Equity Oil Company</td>
<td>March 1984; page 2-52</td>
</tr>
<tr>
<td>Cottonwood Wash Project</td>
<td>American Mine Service</td>
<td>March 1985; page 2-73</td>
</tr>
<tr>
<td>Stone &amp; Webster Engineering</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Foster Wheeler Corporation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Magic Circle Energy Corporation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Direct Gasification Tests</td>
<td>Tosco Corporation</td>
<td>September 1978; page B-4</td>
</tr>
<tr>
<td>Duo-Ex Solvent Extraction Pilot</td>
<td>Solv-Ex Corporation</td>
<td>September 1989; page 2-55</td>
</tr>
<tr>
<td>Eastern Oil Shale In Situ Project</td>
<td>Eastern Shale Research Corporation</td>
<td>September 1989; page 2-55</td>
</tr>
<tr>
<td>Exxon Colorado Shale</td>
<td>Exxon Company USA</td>
<td>March 1985; page 2-73</td>
</tr>
<tr>
<td>Fruita Refinery</td>
<td>Landmark Petroleum Inc.</td>
<td>March 1991; page 2-23</td>
</tr>
<tr>
<td>Geisenkirchen-Schoiven Cyclone Retort</td>
<td>Veba Oel</td>
<td>June 1987; page 2-52</td>
</tr>
<tr>
<td>Japanese Retorting Processes</td>
<td>Japan Oil Shale Engineering Company</td>
<td>September 1989; page 2-56</td>
</tr>
<tr>
<td>Julia Creek Project</td>
<td>placer Exploration Limited</td>
<td>March 1991; page 2-32</td>
</tr>
<tr>
<td>Laramie Energy Technology Center</td>
<td>Laramie and Rocky Mountain Energy Company</td>
<td>June 1980; page 2-34</td>
</tr>
<tr>
<td>Logan Wash Project</td>
<td>Occidental Oil Shale Inc.</td>
<td>September 1984; page S-3</td>
</tr>
<tr>
<td>Means Oil Shale Project</td>
<td>Central Pacific Minerals Dravo Corporation Southern Pacific Petroleum</td>
<td>June 1987; page 2-47</td>
</tr>
<tr>
<td>Nahcolite Mine #1</td>
<td>Multi-Mineral Corporation</td>
<td>September 1982; page 2-40</td>
</tr>
<tr>
<td>Naval Oil Shale Reserve</td>
<td>United States Department of Energy</td>
<td>June 1987; page 2-53</td>
</tr>
<tr>
<td>Oil Shale Gasification</td>
<td>Institute of Gas Technology; American Gas Association</td>
<td>December 1978; page B-3</td>
</tr>
<tr>
<td>Pacific Project</td>
<td>Cleveland-Cliffs Standard Oil (Ohio) Superior</td>
<td>June 1987; page 2-48</td>
</tr>
<tr>
<td>Paraho Oil Shale Full Size Module Program</td>
<td>Paraho Development Corporation</td>
<td>December 1979; page 2-35</td>
</tr>
<tr>
<td>Paraho-Ute Shale Oil Facility</td>
<td>Paraho Development Corporation</td>
<td>December 1986; page 2-47</td>
</tr>
<tr>
<td>RAPAD Shale Oil Upgrading Project</td>
<td>Japanese Ministry of International Trade and Industry</td>
<td>March 1990; page 2-52</td>
</tr>
</tbody>
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### STATUS OF OIL SHALE PROJECTS

#### COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Companies</th>
<th>Date</th>
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<tr>
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<td>Geokinetics Inc.</td>
<td>March 1986;</td>
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<td>March 1985;</td>
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<td>Shale Energy Corporation of America</td>
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<td>Tosco Corporation</td>
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<td>Trans Natal, Gencor, Republic of South Africa</td>
<td>March 1991;</td>
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<td>Triad Donor Solvent Project</td>
<td>Triad Research Inc.</td>
<td>December 1988;</td>
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<td>United States Shale Inc.</td>
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<td>page 2-72</td>
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<td>Talley Energy Systems</td>
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<td>Phillips Petroleum Company</td>
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<td>Standard Oil Company (Ohio)</td>
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<td>United Nations</td>
<td>December 1990;</td>
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<td>Beloba Pty. Ltd.</td>
<td>Yaamba Project</td>
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<td>Stuart Oil Shale Project</td>
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<td>Condor Project</td>
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<td>Chevron Shale Oil Company</td>
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<td>Conoco Inc.</td>
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<td>SHC-3000 Retorting Process</td>
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<td>Fushun Commercial Shale Oil Plant</td>
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<td>RAMEX Oil Shale Gasification Process</td>
<td>2-39</td>
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<td>Jordan Natural Resources</td>
<td>Jordan Oil Shale Project</td>
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<td>Yaamba Joint Venture</td>
<td>Yaamba Project</td>
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PROJECT ACTIVITIES

PEACE RIVER REDUCES OPERATING COSTS

The Peace River oil sands project in northern Alberta, Canada, an operation of Shell Canada Limited, reports a 13 percent reduction in operating costs for 1991 compared to the previous year. According to the company's 1991 annual report, this cost reduction helped to offset lower bitumen prices during the year.

The Peace River project produced 0.3 million cubic meters of bitumen in 1991, the same amount as was produced in 1990. Shell Canada's oil sands leases also remained unchanged from 1990 to 1991.

According to the report, Shell does not expect any sustained improvement in the real price of crude oil for several years. By the end of 1992, the company expects to be operating with some 1,200 fewer full-time employees.

OIL SANDS PRODUCTION FIGURES UPDATED

Synthetic crude oil production at the Suncor plant, while somewhat unsteady, remained relatively high through 1991. Production rates during the fourth quarter of 1991 were up and down, as shown in Figure 1, which illustrates the plant's synthetic crude production for 1990, 1991 and January 1992.

Alberta Energy Resources Conservation Board (ERCB) statistics show that Suncor's synthetic crude oil production in January 1992 increased to 333,340 cubic meters, roughly equivalent to 2 million barrels. This compares to production in December 1991 of 265,083 cubic meters, or about 1.6 million barrels.

While synthetic crude production at the Syncrude plant started rather slowly in the fourth quarter of 1991, both November and December showed extremely good results. Production in December reached over 1 million cubic meters of synthetic crude, the equivalent of more than 6 million barrels.

FIGURE 1

SUNCOR SYNTHETIC CRUDE OIL PRODUCTION, 1990-1992

SOURCE: ERCB

SYNTHETIC FUELS REPORT, JUNE 1992
Syncrude's production dropped slightly in January 1992 to 915,835 cubic meters, or roughly 5.6 million barrels of crude oil. Figure 2 shows the plant's synthetic crude production for 1990, 1991 and January 1992.

###

FORDING-KILBORN JOINT VENTURE TO TEST OIL SANDS PROCESS

Fording Coal Ltd. of Calgary, Alberta, Canada and Kilborn Engineering & Construction Ltd. will invest C$10 million in oil sands extraction technology. The process is expected to reduce costs and the amount of waste byproducts.

The joint venture firm, Bitmin Resources Inc., will demonstrate the Counter Current Drum Separator (CCDS) technique. Fine-mined clay and sand will be sluiced in a drum with hot water. The bitumen then flows from the drum with the water leaving with the clay and sand. The separating process may be performed on-site, and may reduce the cost of production by $3 per barrel. The dry tailings produced from the procedure can be used to backfill the strip mine eliminating the environmental problems produced by wet sludge.

Bitmin Resources plans a 10 tonne per hour demonstration plant in Alberta's Fort McMurray region. The development work on the CCDS method has a planned completion date of 1993.

###

CHEVRON STEEPBANK PROJECT USES 1,600-FOOT HORIZONTAL SECTION

The Chevron Canada Resources Company HASDrive (Heated Annulus Steam Drive) project at Steepbank has continued to expand (see Pace Synthetic Fuels Report, March 1992, page 3-1). Four pilot wells were drilled in August including a 1,600-foot horizontal well. The well is at a 2,800-foot measured depth. In addition to the vertical
producing well, two steam injectors and five temperature observation wells were drilled.

Chevron expects a higher recovery rate by the HASDrive well than by conventional methods. The company estimates recoveries by conventional methods would be around 20 percent. Some 9 billion barrels of oil are present in the reserve.

###

**FIRE DAMAGES SUNCOR UPGRADER**

The fire at Suncor's oil sands plant near Fort McMurray, Alberta, Canada, which occurred in the upgrader section of the plant on April 3, was quickly reduced to controlled burning of residual oil in the affected systems and then extinguished entirely on April 4. The fire was caused by a hole in a valve in a process gas line. There were no injuries and damage was contained to the hydrotreating area of the upgrader.

Bitumen production continued without interruption, but the upgrading operations were affected. All three units for coking, distillation and hydrotreating were taken off line at the time of the fire. The third unit sustained most of the damage from the fire. Structural steel fire proofing prevented support structures from failing, underground cabling reduced electrical and instrument damage, and deluge fire water systems contained the fire. Enhancements to emergency response processes and systems also contributed to damage containment.

Total physical damages of the incident are estimated to be in the C$10 to $20 million range. Any costs in excess of C$12 million are covered by insurance.

Production is expected to remain at normal levels of 60,000 barrels per day throughout the period of repair. However, a portion of the plant's production will temporarily be a lower-value non-hydrotreated distillate product, with full production of synthetic crude to be phased in over a period of 30 to 60 days. The revenue impact is currently estimated to be in the C$7 to $10 million range. Second quarter earnings will reflect the impacts of this event.

Partially offsetting this short-term reduction in revenue, the plant has achieved record production levels in the first quarter of 1992, averaging 64,200 barrels per day, or about 250,000 barrels above the same period last year.

###

**SEPTEMBER STARTUP SCHEDULED FOR UTF**

Japex Oil Sands Ltd. of Calgary, Alberta, Canada will invest $6.5 million over several years in an Alberta Government oil sands test facility near Fort McMurray, Alberta under the terms of a recent agreement announced by Energy Minister R. Orman. Japex Oil Sands Ltd. is a subsidiary of Japan Petroleum Exploration Company Ltd.

The Participation Agreement, signed between Japex and the Alberta Oil Sands Technology and Research Authority (AOSTRA) as reported in the Pace Synthetic Fuels Report, March 1992, page 3-9, brings Japex into a partnership with AOSTRA, seven other industry participants and the Government of Canada in the operation of AOSTRA's Underground Test Facility (UTF). Japex will take an active role in the management of the project.

The UTF, which began operating in 1987, was developed by AOSTRA. Located about 60 kilometers north of Fort McMurray, and developed at a cost of $50 million, the UTF uses horizontal well technology with wells placed from an underground tunnel system for more efficient drilling and operation.

With most of the vast Athabasca oil sands resource inaccessible by conventional surface mining, the UTF was designed to develop new methods of in situ recovery of the oil sands. The UTF reduces costs of testing new recovery technologies. Technology developed using the UTF also minimizes the surface environmental impact of bitumen recovery from oil sands.

At the heart of the UTF are twin shafts, each 3 meters in diameter, that have been sunk from the surface to the Devonian limestone underlying the oil sands 215 meters below the ground surface. A network of tunnels houses a uniquely designed drilling system to drill wells up to and horizontally through the oil sands deposit. About 1.5 kilometers of tunnels have been excavated laterally in the limestone so far.

Currently, the UTF staff are involved in a project called the Steam Assisted Gravity Drainage Process. The project involves six 600-meter horizontal wells drilled in three pairs into the oil sands. The top well is for steam injection and the bottom well produces the heated bitumen. Two thousand barrels per day of bitumen are planned to be produced with this method, with production slated to begin in September 1992.

###

SYNTHETIC FUELS REPORT, JUNE 1992

3-3
FIRST TANGLEFLAGS HORIZONTAL WELL PASSES MILLION BARREL MARK

The 1991 annual report from Sceptre Resources Limited says that production from the company's first horizontal well at Tangleflags North, which was drilled in 1987, surpassed the 1 million barrel mark during 1991. While the area has the potential for 13 similar projects, the company says that further development is dependent on future oil prices.

In Saskatchewan, Canada, development drilling delineated a significant accumulation of heavy oil at Tangleflags East, which is adjacent to Sceptre's steam flood and horizontal production test facility at Tangleflags North.

###
AOSTRA TO COMMISSION 5 TONNE/HOUR TACIUK PROCESSOR

The Alberta Oil Sands Technology and Research Authority (AOSTRA) says the first step towards commercialization of the AOSTRA Taciuk Process (ATP) in oil sands is well under way. Construction is complete on a new mobile ATP oil sands thermal retorting plant that will be used to demonstrate the commercial readiness of the process. The coming renewal of oil sands leases, beginning in 1996, makes the commercial application of the ATP especially timely. AOSTRA's economic studies indicate a reduction in processing cost of 20 to 25 percent compared to present surface mining, extraction, and upgrading technology alternatives. The ATP processes oil sands to produce a pipelineable coker-type distillate product and requires no tailings ponds. A commissioning ceremony has been scheduled for June 1992 in Calgary, Alberta, Canada.

The new AOSTRA 5-tonne-per-hour mobile demonstration plant was constructed in Calgary by UMATAC Industrial Processes. Mounted on highway trailers, the self-contained plant can be transported to oil sands leases for demonstration purposes.

Southern Pacific Petroleum/Central Pacific Minerals of Australia have selected the AOSTRA Taciuk Process over all other available thermal retorting technologies worldwide for the commercial development of their oil shale leases in Australia. Planned is a 4,500 barrel per day commercial demonstration plant which will eventually lead to a 60,000 barrel per day commercial facility.

The process and mechanical reliability have been confirmed by the performance of a 10-tonne-per-hour commercial ATP plant operating in the United States on oily waste materials. The plant, which is owned and operated by Soiltech Inc., has seen over 7,000 hours of operation since startup in 1990. The transportable ATP plant is currently at Waukegan Harbor, Illinois cleaning up some 20,000 tonnes of PCB-contaminated soil.

OGJ REPORTS 24 PERCENT INCREASE IN EOR ACTIVITIES IN 2 YEARS

Worldwide production from enhanced oil recovery (EOR) projects, including heavy oil projects, was 1.5 million barrels per day at the beginning of 1992, an increase of 24 percent over the 1.2 million barrels per day being produced in 1990. The Oil & Gas Journal (OGJ) reported the results of its biennial EOR survey in a recent article. OGJ estimates that China and the former Soviet Union (who did not respond to the survey) produce an additional 0.4 million barrels per day, bringing total world EOR and heavy oil production to 1.9 million barrels per day. This amount represents 3.2 percent of the average 1991 oil production rate of nearly 60 million barrels per day.

In the United States, oil produced from EOR projects now exceeds 10 percent of domestically produced oil. This change in the oil mix results from the combination of increasing EOR and diminishing total domestic oil production, says OGJ.

Figure 1 shows that although the number of United States projects has decreased since 1986, production is continuing to rise.

In Canada, EOR production is up 7 percent. Eighty-three percent of Canadian EOR is from hydrocarbon miscible projects. In addition, Canada is an active area for primary production of heavy oil with steam. The largest project is Esso Resources Canada Ltd.'s Cold Lake field that produces about 90,000 barrels per day. Unlike 2 years ago, the OGJ survey found no plans for new heavy oil projects.

For the world, excluding the United States and Canada, EOR production listed in this survey leaped by 194,200 barrels per day, from 308,300 in 1990 to the current 502,500 barrels per day. Two major contributors were Venezuela and Indonesia's Durian field.

United States EOR

In the United States, the 761,000 barrel per day EOR production rate at the beginning of 1992 was up 104,300 barrels per day from the listing of 2 years ago. This production level is 10.4 percent of the 7.33 million barrel per day United States oil production rate.

Two projects largely account for the 107,100 barrel per day rise in production from CO₂ and hydrocarbon miscible projects. For CO₂ projects, the inclusion of Amerada Hess Corporation's Seminole unit added 30,600 barrels per day. The project started in 1983 but had not been included in prior OGJ surveys.

ARCO Oil and Gas Company's Prudhoe Bay project added 40,000 barrels per day to production from hydrocarbon miscible projects.

Planned Projects

Although the number of hydrocarbon miscible projects has not greatly increased, production from this type of project has more than doubled. Alaska accounts for most of this
change. The three ARCO projects in Alaska are producing 70,000 barrels per day through the hydrocarbon miscible process. The rate in Alaska will continue to increase as ARCO expands the Prudhoe Bay project in stages over the next 4 to 5 years, says OGJ.

This expansion represents most of the $1.3 billion planned for United States projects listed in Table 1.

The remaining amount of expenditures is primarily for new CO₂ projects. Six of the planned CO₂ projects in Table 1 are in West Texas.

One project in Table 1, Texaco Exploration & Production Inc.'s Mabee unit CO₂ project, began producing in January 1992. The $104 million project will use a water-alternating-gas process for injecting CO₂.

According to OGJ, there is a chance that several recent developments may spur the startup of projects besides those listed as planned in Table 1. These developments include the 15 percent tax credit for EOR projects, the completion of the Kern River/Mojave pipeline, and funding by the United States Department of Energy (DOE) for demonstration projects.

DOE is planning to fund proposed projects for enhancing production from fluvial dominated deltaic reservoirs. About a third of the proposed 35 projects are for tertiary recovery. DOE expects to fund about 14 of the 35 projects.

California independent producers are seeking changes that would clarify parts of the tax credit regulations. One problem is that the regulations, as written in December 1991, will not permit operators to take the credit if they changed from cyclic steam injection to steam drive.

The completion of the Kern River pipeline will make available more gas (from Wyoming, Colorado, and possibly Canada) for use as a fuel to generate steam. About 60 percent of the pipeline's capacity will be used for EOR projects.

Non-United States EOR

According to the OGJ survey, the three areas outside of the United States with the most EOR production are:
### Table 1

**U.S. PLANNED EOR PROJECTS BY TYPE**

<table>
<thead>
<tr>
<th>Operator</th>
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<th>Gravity, °API</th>
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<td>ARCO</td>
<td>Alaska</td>
<td>8,800</td>
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<td><strong>Miscible</strong></td>
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<td>Steam</td>
<td>Anderson Co., TX</td>
<td>425</td>
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<td>3/92</td>
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<tr>
<td>Enercap</td>
<td>Anderson Co., TX</td>
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<td>18.4</td>
<td>9/92</td>
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<tr>
<td>MacPherson</td>
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<td>15 - 16</td>
<td>4/93</td>
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<td>Unocal</td>
<td>Kern CO., CA</td>
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<td>1/92</td>
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<td>Phillips</td>
<td>Osage Co., OK</td>
<td>2,900</td>
<td>39</td>
<td>1/92</td>
</tr>
</tbody>
</table>

Venezuela with 234,200 barrels per day, Indonesia’s Duri field with 180,000 barrels per day and Canada with 164,700 barrels per day. Steam is used in both Venezuela and Duri, but hydrocarbon miscible projects account for 83 percent of the Canadian production. Canada also has an additional 106,800 barrels per day of heavy oil being produced by thermal methods.

Table 2 lists 12 planned EOR projects outside for the United States. Planned investment is over $176 million.

Because of the potential for developing less expensive oil, Venezuela is not expected in the next 2 years to expand its EOR production.

**China**

Information from the China National Petroleum Corporation indicates that cyclic steam projects are ongoing in four regions: Liao Nining, Karamay, Shengli, and Nan Yang. More than 10 reservoirs are involved, says OGJ. Besides cyclic steam, China has four steamflood pilots.

The Chinese projects encompass more than 3,500 wells over an area of 32,000 acres. Depth of the Chinese reservoirs ranges from 650 to 5,250 feet.

**Former USSR**

Tatarstan was the only part of the former Soviet Union to respond to OGJ’s survey.

All of Tatarstan’s current EOR projects are in the giant Romashkino field. From the three ongoing projects, EOR production is about 1,800 barrels per day. Tatneft, a Russian oil and gas company, plans to add two more projects. Both are expected to start up during 1992.

S.A. Zhdanov and M.L. Surguchow described Soviet EOR projects in a paper presented during the 13th World
TABLE 2

PLANNED PROJECTS EXCLUDING U.S. BY COUNTRY

<table>
<thead>
<tr>
<th>Project Type</th>
<th>Operator</th>
<th>Country</th>
<th>Depth, Ft.</th>
<th>Gravity, °API</th>
<th>Start Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Immiscible</td>
<td>Vikor</td>
<td>Canada/Alta.</td>
<td>5,000</td>
<td>42</td>
<td>4/92</td>
</tr>
<tr>
<td>Hydrocarbon Misc.</td>
<td>Canadian Hunter</td>
<td>Canada/B.C.</td>
<td>1,000</td>
<td>57</td>
<td>7/92</td>
</tr>
<tr>
<td>CO₂ Miscible</td>
<td>Shell</td>
<td>Canada/Sask.</td>
<td>4,500</td>
<td>27</td>
<td>2/92</td>
</tr>
<tr>
<td>Steam Drive</td>
<td>Texas Petroleum</td>
<td>Colombia</td>
<td>2,100</td>
<td>12.8</td>
<td>1/92</td>
</tr>
<tr>
<td>Steam Drive</td>
<td>Wintershall AG</td>
<td>Germany/L. Saxony</td>
<td>2,800</td>
<td>24.5</td>
<td>4/92</td>
</tr>
<tr>
<td>Hydrocarbon Misc.</td>
<td>Total</td>
<td>Indonesia/Kalimantan</td>
<td>1,500</td>
<td>30</td>
<td>1994</td>
</tr>
<tr>
<td>Microbial</td>
<td>Tatneft</td>
<td>Russia/Tatarstan</td>
<td>5,740</td>
<td>44.3</td>
<td>5/92</td>
</tr>
<tr>
<td>Surfactant</td>
<td>Tatneft</td>
<td>Russia/Tatarstan</td>
<td>5,740</td>
<td>44.3</td>
<td>6/92</td>
</tr>
<tr>
<td>Steam Drive</td>
<td>Trintoc</td>
<td>Trinidad</td>
<td>1,200-2,500</td>
<td>16-18</td>
<td>1993</td>
</tr>
<tr>
<td>Steam Drive</td>
<td>Maraven</td>
<td>Venezuela</td>
<td>4,100</td>
<td>18</td>
<td>1/92</td>
</tr>
<tr>
<td>Steam Soak</td>
<td>Lagoven</td>
<td>Venezuela/Monagas</td>
<td>3,600</td>
<td>9</td>
<td>2/92</td>
</tr>
</tbody>
</table>

Petroleum Congress in Buenos Aires, Argentina in October 1991. According to them, in 1990 the former USSR had 247 active projects producing about 228,000 barrels per day. The primary areas of activity were Kazakhstan, Tatarstan, and West Siberia. Horizontal wells and bottom hole heat generators are being investigated for thermal applications.

Steam drive is being used in reservoirs with depths ranging from 650 to 6,500 feet.

Usinskoye field has the largest steam drive project. The 200-foot thick reservoir is a fractured carbonate at a depth of 4,265 feet.

In situ combustion has been ongoing in the Karazhanbas oil field, West Kazakhstan, since 1981. A linear well pattern is used for both producers and injectors. The 26-foot thick sandstone reservoir is at a depth of 1,150 feet.

Samotlor oil field is the largest area where hydrocarbon miscible and immiscible projects are taking place. The reservoirs in the field lie between 5,280 and 6,800 feet.

Because of complicated technological problems of transportation and injection, CO₂ EOR is only at the pilot stage. In all of the former USSR’s oil producing regions, no natural CO₂ reservoirs have been found.

By the year 2000, Zhdanov and Surguchov estimate that the former USSR may be producing, by EOR methods, 490,000 to 790,000 barrels per day.

PETRO-CANADA CUTS WORK FORCE AND SPENDING ON OIL SANDS

Petro-Canada, Canada’s second largest oil and gas company, has announced plans to cut its work force by approximately 1,200 by the end of 1993. As part of an overall restructuring plan, the company will refocus and resize its Resources Division.

Future investment in Resources will be targeted to the four businesses with the greatest potential to consistently deliver strong performance: Western Canada light oil, natural gas, natural gas liquids and Grand Banks light oil. Investment in other businesses will be strictly limited, largely to contractual obligations.

The Resources Division will intensify its rationalization program in order to concentrate on its best assets and significantly reduce the size of its organization. In Western Canada, the number of producing entities will be reduced from some 330 at the end of 1991 to about 100. According to Petro-Canada, these steps will permit substantial reductions in operating and overhead costs, including staff levels. There will be little net impact on production volumes, however.

Petro-Canada’s president, J. Stanford, said the company will cut its spending on oil sands ventures significantly. The company will also cut spending on the production of heavy crude oil and international exploration and development projects.

W.H. Hopper, chairman of Petro-Canada, commented, “The change we are announcing in Resources is a key element in our drive to improve profitability. In both our upstream and downstream operations, we are taking steps to focus our capi-

SYNTHETIC FUELS REPORT, JUNE 1992
was constructed from the Manito Unity pump station to the Senlac heavy oil area. This system was constructed to support the increased horizontal drilling in the Senlac area, and crude movement was expected to begin in early 1992.

Heavy oil development continued in the Bodo area with three vertical wells and three horizontal wells, one of which offsets the Bodo steamflood.

SOLV-EX LOOKING FOR FINANCING FOR BITUMOUNT PROJECT

The most recent Securities and Exchange Commission Form 10-Q filed for Solv-Ex Corporation says that the company is continuing in its efforts to obtain financing for its proposed Bitumount Project. The company has also outlined plans to apply its technology for use in the recovery of oil, minerals and metals from various leases in Canada and other resources in the United States. The company is currently marketing its plans to various governmental agencies, oil sands producers, mining companies and institutional investors. According to the form, there is, however, no assurance that the company will secure the necessary funding.
NEW OIL SANDS RESEARCH PROGRAM AUTHORIZED

The Canadian Federal Government, through the Canadian Centre for Mineral and Energy Technology, is joining with the Alberta Oil Sands Technology and Research Authority, the Alberta Research Council and industry participants to fund a new 5-year program in oil sands recovery. A goal of the $20 million program is to generate new technology which will reduce heavy oil and bitumen production costs. Research will be conducted primarily by the Alberta Research Council.

Twelve national and international oil companies will also contribute to the program's $4 million annual budget through membership fees of $75,000. In return, they receive direct access to research results developed under the program, commercial usage rights of project technology, and the opportunity to play a major role in developing the research program. The research results remain confidential for 15 years, or until participants consent to release the findings into the public domain.

The new 1991-1996 research program which emphasizes high-risk, high-reward research for both oil sands and heavy oil recovery is directed by an industry-driven management system.

ERCB REVIEWS YEAR IN OIL SANDS

The Alberta (Canada) Energy Resources Conservation Board (ERCB), after 53 years of regulating an expanding energy industry, now finds itself confronted with a fundamentally different set of realities. In particular there are economic and environmental factors making the development of the province's huge oil sands reserves more difficult. Nonetheless Alberta's oil sand projects continue to advance. Synthetic crude oil production (Figure 1) reached a record 13 million cubic meters in 1991. Crude bitumen production dropped almost 9 percent because of low prices for heavier crude oil which includes bitumen.

Water, Air and Tailings Top Sands Environmental Agenda

Water use by in situ oil sands and heavy oil projects continued to be a major issue in 1991. At Cold Lake, a prolonged drought has reduced water levels to their lowest in 30 years. As a result, water withdrawal from the lake was suspended in October 1991. Cold Lake is the major water source for Esso Resources Canada's nearby commercial in situ project.

During 1991, Alberta Environment's Regional Air Quality Coordinating Committee completed a full year of operation of its odor protocol program in the Fort McMurray/Fort McKay area. Growing public and media awareness resulted in a 70 percent success rate in tracking odor incidents to a specific industrial source in 1991.

Suncor Inc. and Syncrude Canada Ltd. continued to research new ways of reclaiming fine tailings in 1991. Recent tests involved capping the fine tailings with fresh water. Early results seem to indicate that microbial activity naturally detoxifies the water above the tailings.

In Situ Developments Proceed Cautiously

The Cold Lake area of Alberta has some of the most advanced in situ oil sands developments in the province. During 1991, a key area of development was on the Primrose Weapons Range north of Cold Lake.

Amoco Canada Petroleum Company Ltd. and Suncor are proceeding with new initiatives at their respective commercial project sites. For Amoco, the development comes with the recent ERCB approval for seven horizontal wells to maximize bitumen recovery under a steam stimulation/gravity drainage process. For its part, Suncor applied to the ERCB in November 1991 to increase primary bitumen production as much as 2,000 cubic meters per day.

In the Lindbergh area, Amoco's application for Phase 2 of the Elk Point commercial project continued through the application review and public consultation process.

Oil Sands Experiments

Esso tested borehole mining techniques for in situ reservoirs. Further evaluation will be required before proceeding.

The use of horizontal wells is being tested in the Wabasca area by CS Resources at Pelican Lake. In 1991, an additional eight horizontal wells were drilled to about 1,000 meters in length. These are some of the longest horizontal wellbores ever drilled in oil sands areas.

In June 1991, the Alberta Oil Sands Technology and Research Authority applied to expand experimental operations at the Underground Test Facility near Fort McMurray.

SYNTHETIC FUELS REPORT, JUNE 1992
This project entails six new horizontal wells to test the production capabilities of longer wellbores reaching up to 600 meters. Bitumen production rates at the site are expected to increase from 400 to 500 cubic meters per day.

**OSLO Application Review Team Winds Down**

In April 1991, after 3 years of work, the OSLO (Other Six Leases Operation) group decided not to proceed with a proposed $4 billion oil sands plant as planned.

During the project’s preparatory phase, the ERCB facilitated the formation of the OSLO Application Review Team with representatives from OSLO, provincial and federal governments, Native groups, and local municipalities.

###
PELICAN LAKE HORIZONTAL WELL COSTS DOWN, PRODUCTIVITY UP

T. Fontaine, et al., of CS Resources Limited, discussed project development for the Pelican Lake area at the Ninth Annual Heavy Oil and Oil Sands Technical Symposium in March in Calgary, Alberta, Canada. The company has drilled and is currently operator of 17 horizontal wells in a thin, heavy oil pool in the Pelican Lake area. The horizontal wells were drilled in three phases: eight wells in 1988, five wells in 1990 and four wells in 1991. At each phase of development, the company was able to improve on well costs and increase productivity.

History

The Pelican Lake area is located 175 miles north of Edmonton, Alberta. The main oil bearing formation is the Wabiskaw "A" with an average net oil pay of 5 meters. The API gravity of the oil is 14° and the viscosity is between 600 and 1,000 centipoise at 20°C. Upwards of $100 million had been expended on 100 vertical and deviated wells in the Pelican Lake area by others prior to CS Resources acquiring the property. A variety of enhanced oil recovery processes were tested including: water flooding, cyclic steam stimulation, steam flooding and fire flooding. There was no further drilling until 1988 when CS Resources drilled eight horizontal wells.

Horizontal wells were a natural choice of development in this area for the following reasons:

- Difficult muskeg locations required expensive road and lease construction.
- Vertical production was clearly uneconomic due to poor productivity and low recoveries.
- A horizontal well contacts considerably more of the thin productive reservoir section than a vertical well.
- Horizontal wells offer the potential for cost improvements. The cost per meter of pay zone penetrated is reduced; the utilization of a single drilling pad for four or more horizontal wells improves infrastructure costs per well.

Some of the initial wells did not perform as well as expected. Through further technical work and discussion between the geology, reservoir and drilling disciplines, the probable reasons for the under-performance were reviewed. With the knowledge obtained from the original program, five more horizontal wells were drilled in 1990 and four more were drilled in 1991. The well production performance for all three phases is compared to vertical well production in Figure 1.

Phase I (1988)--Eight Horizontal Wells

One of the justifications for horizontal drilling in this thin reservoir was to expose a large area of reservoir to the well while considerably reducing the near-wellbore pressure drop characteristic of conventional vertical wells.

The optimum drainage area for Pelican Lake vertical wells was estimated to be 6 hectares (15 acres). Therefore the optimum spacing between horizontal wells was determined to be approximately 280 meters. The wells were drilled in a star pattern from a pad so the distance between the wells increased away from the pad.

The first eight wells drilled had horizontal sections of about 500 meters and took approximately 9 days each to drill with a polyacrylamide/polymer mud system. The average drilling and completion cost was $621,000.

Phase II (1990)--Five Horizontal Wells

As a result of work on the initial wells, the 1990 wells were drilled away from the higher water saturated area of the pool and greater effort was made to avoid drilling into the Bar Margin, which had proved to be a less productive area.

The 1990 drilling program included longer horizontal sections, an improvement in accurately finding the 5 meter target sand and maintaining the drainhole in the reservoir. The average drilling time for the five wells was 8.8 days each with an average cost of drilling, casing and completion of $441,000. The average horizontal length was 887 meters with the longest horizontal section being 1,047 meters. The first four wells encountered an average of 78 percent of high quality reservoir. A change in philosophy of how to place the trajectory in the reservoir resulted in the final well encountering almost 100 percent of the high quality sand.

Phase III (1991)--Four Horizontal Wells

Through continual improvement in the understanding of the area geology and experience in drilling the formation, all four 1991 wells contacted almost 100 percent of good quality reservoir throughout the horizontal section.

The 1991 drilling phase included four major variances to the program:
- An attempt would be made to maximize length and minimize costs.

- A "J" Profile would be attempted in the build section to provide a low gravity sump and accurately determine entry point geology.

- A horizontal lateral arm would be attempted off a main horizontal to maximize contact with the reservoir.

- A build and turn profile would be utilized in the build section of two wells in order to optimally space two parallel horizontal wellbores.

Overall results of the most recent phase were as follows:

- The horizontal section of the one well was 1,321 meters from intermediate casing point to total depth. This horizontal wellbore results in a horizontal section to T.V.D. ratio of 3.2 meters per meter.

- A 496 meter lateral arm was completed off the horizontal section of a 1,137-meter main hole section.

- The "J" well was a limited success with a horizontal section of only 907 meters.

The average drill, case and completion cost of the 1991 wells was $540,000. The wells took an average of 7.5 days to drill with the average horizontal section being 1,290 meters. The cost per horizontal meter has dropped from $1,240 per meter in 1988 to $420 per meter in 1991. Figure 2 illustrates how the costs of drilling per meter have improved over the life of the project.
FIGURE 2

PELICAN LAKE AREA DRILLING AND COMPLETION COSTS

Cost/Meter

$2,000
$1,500
$1,000
$500
$0

A14-10  B14-10  C14-10  D14-10  A11-15  B11-15  C11-15  D11-15  3-17  4-20  7-20A  6-21  5-21  5-4  6-22  5-22  11D-16

SOURCE: CS RESOURCES LIMITED
BITUMEN EXTRACTION IN SESA PROCESS CORRELATED WITH ASPHALTENE CONTENT

B.D. Sparks, et al., of the Institute for Environmental Chemistry in Ottawa, Ontario, Canada discussed the "Effect of Asphaltene Content on Solvent Selection for Bitumen Extraction by the SESA Process" at the 1991 Eastern Oil Shale Symposium in Lexington, Kentucky in November.

According to the authors, many anhydrous separation schemes have been developed in order to avoid the tailings problem associated with Hot Water Extraction (HWE) of bitumen from Athabasca oil sands. The Solvent Extraction with Sand Agglomeration (SESA) process is a solvent extraction method which utilizes concurrent particle aggregation in order to overcome difficulties normally encountered in solvent-liquid separation in the presence of fines.

Bitumen itself contains a high proportion of poorly soluble asphaltenes. Unpredictable precipitation of this component can cause process problems. Consequently, the selection of an appropriate solvent is an important factor in optimizing bitumen extraction.

Background

At the present time there are two commercial oil sands mining plants operating in the Athabasca region of Alberta, Canada. Both plants use HWE technology as the primary means of bitumen separation. While the HWE process has been technically successful, the problems associated with the reclamation of huge quantities of tailings sludge have not yet been entirely resolved. Solvent extraction is attractive because it eliminates wet tailings and gives high recovery of bitumen, from even low grades of oil sands. However, although bitumen extractability is high, the presence of fines (<325 mesh) in the ore can inhibit the separation of produced bitumen solutions from the extracted solids.

The SESA process overcomes this solids-liquid separation problem by combining solvent extraction with sand agglomeration. Agglomeration is a process in which particulate solids in liquid suspension are formed into dense aggregates by means of agitation in the presence of a second liquid, the latter must preferentially wet the solids and be immiscible with the extracting solvent. The naturally water-wet condition of the particles comprising oil sands make this system an ideal candidate for application of sand agglomeration technology. Oil sands ore is first slurried with a bitumen solvent, which also acts as the solids suspending medium. The addition of controlled amounts of water then allows the particles to be bound together into agglomerates; agitation by tumbling and surface tension effects provide the driving forces for this solids aggregation. Solvent extraction and agglomeration occur concurrently. Use of a suitable device allows a solids-liquid separation to give a clean bitumen solution and a solid, aggregated tailings with a relatively low bitumen and solvent content. Solvent selection must therefore be based on the degree of immiscibility with water as well as the ability to dissolve bitumen.

Bitumen contains three main components: maltenes, resins and asphaltenes. Whereas maltenes are infinitely soluble in paraffinic solvents, the complete dissolution of resins and asphaltenes requires the use of relatively polar, aromatic solvents, such as benzene or toluene. In conventional practice, asphaltenes are separated from maltenes by adding a large excess of pentane to a solution of bitumen in benzene. However, the solubility of asphaltenes in paraffins also increases in proportion to the number of carbon atoms in the solvent and this provides a means of fractionating asphaltenes on the basis of their molecular weight. The selected bitumen solvent must therefore have the proper balance between paraffinic and aromatic components.

For economic reasons the most appropriate solvent for bitumen extraction is a cut from the products of bitumen upgrading; depending on the process used, two or three fractions of lighter oil are available. In current practice with the HWE process a light naphtha is used as a bitumen diluent prior to froth treatment. For the study reported at the symposium, the same diluent naphtha was compared to Stoddard solvent (Varsol) and toluene in order to assess its suitability as a solvent in the SESA process. Determination of asphaltene content in both separated bitumen and the residual organics associated with extracted sand was reported.

Process Description

A simplified flow diagram of the proposed SESA process is shown in Figure 1. Feed is transported into the extraction-agglomeration unit where it is contacted with extracting solvent and water. The unit is a rotating tumbler operating at about 15 percent of its critical speed. Mixing of the ore, solvent and water is assisted by steel rods or an autogenous charge of rocks. The solvent stream is a recycled, dilute bitumen solution from a later stage of the process. Bitumen dissolution and sand agglomeration occur concurrently in the tumbler. The water added to the system is captured by the water-wet particulates and causes them to adhere together through capillary action between surface films. Agglomeration is very rapid and some undissolved bitumen is occluded within the particulate structure. The tumbling charge of steel rods results in the breakdown of agglomerates, continuously re-exposing entrapped bitumen to the extracting solvent. A balance between constructive and destructive forces is eventually set up which allows the agglomerate size to be controlled within a desirable size range of 0.5 to 1.5 millimeters, for effective solid-liquid separation. The extracted, agglomerated sand is countercurrently washed with
progressively cleaner solvent to remove residual bitumen solution.

The washed agglomerates are virtually free of bitumen but contain about 4 to 6 weight percent residual, clean solvent. Solvent is largely displaced from the internal pores by water during agglomeration and consequently it is only weakly held in the interstitial pore spaces. This residual solvent is recovered in a rotating, tubular dryer with internal steam stripping.

Solvent Comparison

Diluent naphtha is the solvent of choice for bitumen extraction from oil sands.

Bitumen recovery increased with the solvent power of the liquids. It is to be expected that bitumen losses are largely the result of a combination of undissolved or precipitated asphaltenes as well as bitumen solution entrained within the agglomerated solids.

The experimental results suggest that asphaltene is precipitated from naphtha solution and is then filtered from the wash liquor during the solid-liquid separation step. In all cases the residual organic contained a significantly higher asphaltene content than the original bitumen. In particular, the sample extracted with naphtha, containing a low concentration of predissolved bitumen, had the highest amount of asphaltene entrapped in both inter- and intra-agglomerate pores. A comparison of the asphaltene content of residual organic associated with agglomerates extracted with the different solvents (containing the same bitumen concentration) is shown in Figure 2. The asphaltene content of residual organic approaches that of bitumen as the solvent power increases, that is, naphtha < Varsol < toluene.
Conclusions

In the solvent extraction of oil sands the degree of bitumen extraction can be correlated to the calculated Hildebrand solubility parameter of the solvent. For poor solvents the undissolved bitumen, after extraction, is significantly enriched with asphaltene compared to the “whole” bitumen. It appears, then, that much of the recovery loss in solvent extraction results from the insolubility of asphaltene in solvents with a low aromatic content. From a process point of view the selective loss of asphaltene may well be beneficial in that upgrading of this component normally presents difficulties.

The authors note that bitumen solutions in diluent naphtha tend to be unstable and asphaltene can be precipitated unpredictably during processing. This problem can be largely overcome by preloading the naphtha with bitumen at a concentration of at least 25 weight percent. Comparison of the results for naphtha and Varsol indicates that removal of the lower boiling (lower molecular weight) components from naphtha would also help to stabilize bitumen solutions in this solvent.

BITUMEN SEPARATED FROM OIL SANDS BY ULTRACENTRIFUGATION

The Alberta Research Council has studied ultracentrifugation as a method to recover bitumen from oil sands. D.J. Henry and B.J. Fuhr tested three oil sands of varying grades from Suncor Inc. and Syncrude Canada Ltd. by placing the sands in specially designed tubes and centrifuging for 2 hours at 198,000 G at 20°C. For all grades of oil sand, approximately 70 percent of the bitumen was recovered. They reported their results at the 1991 Eastern Oil Shale Symposium held in Lexington, Kentucky in November.

The recovered bitumen was compared to the residual remaining on the sand, and to that extracted by the conventional Soxhlet technique. The ultracentrifuged bitumen contained some emulsified water and a small amount of fine solids. The solvent extracted material was water-free, but contained a small amount of residual solvent and fine solids. Bitumen recovery could not be linked to oil sand grade.

The authors found that the ultracentrifuge caused some fractionation of the bitumen, resulting in a product slightly enriched in asphaltene components higher in sulfur and nitrogens compared to the solvent extracted material. The residual bitumen remaining on the sand was correspondingly slightly depleted in asphaltenes. As evidenced by gas chromatographic simulated distillation data, ultracentrifugation did, however, retain the light (180°C to 220°C) components of the bitumen which were lost during the solvent removal step following solvent extraction. Other analyses such as density, viscosity, and elemental composition verified that ultracentrifugation resulted in some fractionation of bitumen components.

Densities of the ultracentrifuged bitumen were in reasonable agreement with those of the solvent extracted material.

The ultracentrifuge method removes bitumen mechanically from the oil sand and should result in a bitumen unaltered by solvent handling techniques. Unfortunately, the ultracentrifuge removes only a portion of the total bitumen available leaving a residual bitumen on the sand.

Assuming that the solvent techniques remove 100 percent of the bitumen from the sand, the ultracentrifuge recovers between 50 and 70 percent of the bitumen available to it.
Overall the ultracentrifuged bitumen is low in solids and not significantly higher than that of the toluene extracted bitumen.

Simulated distillation data indicate the solvent extracted bitumen had consistently higher initial boiling points than the ultracentrifuged bitumen. Coupled with its retention of low boiling components, the ultracentrifuged bitumen had the least amount distilled off by 540°C indicating an enrichment in the higher boiling components. On the other hand, the bitumen extracted from the residual sand after ultracentrifuging contained the most under 540°C components which is consistent with the preceding observation.

The density data in Table 1 indicate a reasonable agreement between ultracentrifuged bitumen and solvent extracted bitumen. Apparently, the effects of low boiling components and slightly higher asphaltene contents in the ultracentrifuged bitumens almost cancel each other. A lower density for the ultracentrifuge residual would have been expected due to its slightly lower asphaltene content, but this was not observed.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Ultra-centrifuge</th>
<th>Ultra-centrifuge Residual</th>
<th>Toluene Extraction</th>
<th>Methylene Chloride Extraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.0141</td>
<td>1.0180</td>
<td>1.0153</td>
<td>1.0117</td>
</tr>
<tr>
<td>2</td>
<td>1.0059</td>
<td>1.0084</td>
<td>1.0058</td>
<td>1.0093</td>
</tr>
<tr>
<td>3</td>
<td>1.0085</td>
<td>1.0125</td>
<td>1.0109</td>
<td>1.0096</td>
</tr>
</tbody>
</table>

The data show that nitrogen and sulfur decrease in the residual sample. Sulfur and nitrogen are associated with the asphaltenes of bitumen and demonstrate once again that the asphaltenes have a greater tendency to flow out of the oil sand under ultracentrifuge conditions.

###

**TWICE-REGENERATED HYDROTREATER CATALYST SUCCESSFUL AT SYNCRUDE**

S. Yui and G. Brierley of Syncrude Canada Ltd. discussed their commercial experience with hydrotreating of hydrocracker and virgin light gas oils from Athabasca bitumen using regenerated NiMo catalysts. Speaking at the Annual Meeting of the National Petroleum Refiners Association in New Orleans, Louisiana in March, the authors explained that twice-regenerated NiMo catalyst has been used successfully in a Syncrude commercial hydrotreater processing bitumen-derived hydrocracker and virgin light gas oils. The run length was 25 months or 81 barrels of feed per pound of catalyst. The unit run was terminated because of high reactor pressure drop due to treating fines- and sodium-contaminated coker gas oil, not because of catalyst exhaustion. Decrease in catalyst activity during this period corresponded to a 13°C increase in reactor temperature.

**Background**

Syncrude Canada operates a surface mining oil sands plant at the Athabasca oil sand deposit in northern Alberta and produces synthetic crude oil from the extracted bitumen. The bitumen is upgraded in two fluid cokers and an ebullated-bed hydrocracker (LC-Finer), followed by hydrotreating of distillates in five hydrotreating units; two for naphtha, one for light gas oil, and two for heavy gas oils. As part of a capacity addition program, the company installed the LC-Finer and the associated LGO hydrotreater in 1988. All other upgrading units went onstream in 1978. The total amount of catalyst required for the five hydrotreaters exceeds 2.5 million pounds. Because the replacement cost of catalyst is substantial, efforts have been directed toward a strategy of catalyst management, which includes use of regenerated catalysts and evaluation of their hydrotreating activity in a pilot plant.

Currently, the LGO hydrotreater treats a mixture of hydrocracker and virgin light gas oils.

**Catalyst and Feed**

The catalyst used in the LGO hydrotreater is a mixture of various brands of 3rd cycle NiMo catalysts, after use in the Syncrude naphtha hydrotreater then in the HGO hydrotreater, with commercial regeneration after each use. Table 1 shows properties of the 3rd cycle catalyst of a specific batch.

The feed is a mixture of hydrocracker (LC-Finer) LGO and virgin LGO which is stripped from bitumen. When adequate
TABLE 1

PROPERTIES OF TWICE-REGENERATED CATALYST

<table>
<thead>
<tr>
<th>Metal Analysis, wt%</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>NiO</td>
<td>3.70</td>
<td></td>
</tr>
<tr>
<td>MoO₃</td>
<td>19.07</td>
<td></td>
</tr>
<tr>
<td>V₂O₅</td>
<td>0.84</td>
<td></td>
</tr>
<tr>
<td>Loss on Ignition, wt%</td>
<td>0.89</td>
<td></td>
</tr>
</tbody>
</table>

Physical Properties

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Length, mm</td>
<td>3.69</td>
<td></td>
</tr>
<tr>
<td>Average Diameter, mm</td>
<td>1.45</td>
<td></td>
</tr>
<tr>
<td>App. Bulk Density, g/cm³</td>
<td>0.729</td>
<td></td>
</tr>
<tr>
<td>Surface Area, m²/g</td>
<td>134</td>
<td></td>
</tr>
<tr>
<td>Pore Volume, cm³/g</td>
<td>0.39</td>
<td></td>
</tr>
</tbody>
</table>

Pressure Drop and Product Quality

The pressure drop increased rapidly when coker gas oil was charged for several months in early 1990 (52 to 62 barrels per pound). The unit otherwise could have run until about the 100 barrel per pound mark when the maximum allowable pressure drop (160 psig) was reached. The coker gas oil was found to contain excessive fines and sodium chloride which contributed to the pressure drop buildup.

The hydrotreating reduction was about 85 to 95 percent for sulfur and 60 to 75 percent for nitrogen. Sulfur is easier to remove than nitrogen.

ORIMULSION SEEN AS DESIRABLE FEEDSTOCK FOR GASIFICATION

Using Orimulsion for gasification feedstock in an integrated gasification combined cycle (IGCC) plant offers all of the environmental and efficiency advantages of coal IGCC. In addition, an Orimulsion IGCC may have an economic advantage over a coal based IGCC plant.

The feasibility of Orimulsion gasification is the topic of a paper by D. Heaven of Fluor Daniel and

TABLE 2

PROPERTIES OF TYPICAL HYDROCRACKER AND VIRGIN LGO’S FROM ATHABASCA BITUMEN

<table>
<thead>
<tr>
<th></th>
<th>Hydrocracker LGO</th>
<th>Virgin LGO</th>
<th>Coker Gas Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>API Gravity, degree</td>
<td>27.5</td>
<td>28.5</td>
<td>12.4</td>
</tr>
<tr>
<td>Reflective Index</td>
<td>1.4970</td>
<td>1.4866</td>
<td>1.5570</td>
</tr>
<tr>
<td>Sulfur, wt%</td>
<td>1.05</td>
<td>1.52</td>
<td>4.05</td>
</tr>
<tr>
<td>Nitrogen, wppm</td>
<td>1640</td>
<td>305</td>
<td>3180</td>
</tr>
<tr>
<td>Bromine Number, g/100g</td>
<td>13</td>
<td>7.3</td>
<td>26</td>
</tr>
<tr>
<td>Aniline Point, °C</td>
<td>50</td>
<td>50</td>
<td>34</td>
</tr>
<tr>
<td>Distillation (ASTM D2887), °C</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1%</td>
<td>169</td>
<td>144</td>
<td>232</td>
</tr>
<tr>
<td>5%</td>
<td>199</td>
<td>175</td>
<td>269</td>
</tr>
<tr>
<td>10%</td>
<td>218</td>
<td>197</td>
<td>291</td>
</tr>
<tr>
<td>30%</td>
<td>268</td>
<td>239</td>
<td>350</td>
</tr>
<tr>
<td>50%</td>
<td>308</td>
<td>275</td>
<td>396</td>
</tr>
<tr>
<td>70%</td>
<td>344</td>
<td>311</td>
<td>442</td>
</tr>
<tr>
<td>90%</td>
<td>389</td>
<td>365</td>
<td>498</td>
</tr>
<tr>
<td>95%</td>
<td>411</td>
<td>391</td>
<td>520</td>
</tr>
<tr>
<td>99%</td>
<td>448</td>
<td>442</td>
<td>549</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, JUNE 1992
E. Hernandez-Carstens of Bitor America Corporation. Their paper was presented at the Council on Alternate Fuels Annual Meeting held in Charleston, South Carolina at the end of April.

Orimulsion is the trade name given to the emulsion containing about 70 percent Orinoco bitumen and 30 percent water. It is marketed by Bitor America Corporation, a subsidiary of Petroleos de Venezuela, the Venezuelan national energy corporation.

The bitumen reserves, located in eastern Venezuela near the Orinoco River, consist of approximately 1.2 trillion barrels, the largest known reservoir in the world. The recoverable reserves are estimated at 267 billion barrels.

Orimulsion Gasification

The general concepts underlying Orimulsion IGCC are similar to those for coal IGCC. High temperature conversion of feedstock to medium BTU gas is followed by thorough gas cleanup prior to combustion in a combined cycle power block. Orimulsion gasification is inherently simpler than coal gasification because there is no need for coal handling, coal grinding or slag handling facilities. A block flow diagram for an Orimulsion IGCC plant is presented in Figure 1.

For Orimulsion gasification, an oxygen plant is included to improve overall plant efficiency and to reduce the size of gasification plant equipment. Orimulsion contains ample water for gasification so no additional water or steam is required at the gasifier.

The gasifier is conceptually similar to a Texaco coal gasifier. A slurry medium is unnecessary because the Orimulsion is sufficiently fluid for direct pumping to the gasifier. Use of a fire tube waste heat boiler reduces costs over those of a Texaco coal gasifier equipped with waste heat recovery, according to the paper.

The primary product of gasification is a medium BTU gas consisting of hydrogen, carbon monoxide, carbon dioxide, nitrogen and water vapor. Sulfur is recovered as high grade elemental sulfur and sold. The Orimulsion feed contains a

---

**FIGURE 1**

**ORIMULSION GCC**

![Diagram of ORIMULSION GCC](source.png)

**SOURCE:** FLUOR DANIEL

SYNTHETIC FUELS REPORT, JUNE 1992

3-20
significant amount of nickel and vanadium, which may be recovered and sold to metals processors.

Performance

According to the paper, Orimulsion IGCC offers all of the environmental and efficiency advantages of coal IGCC. The performance of an Orimulsion IGCC plant is similar to that of a coal IGCC plant.

A case developed in early 1991, based upon two General Electric 7F gas turbines, produced a net power output of 472 megawatts using 22,360 barrels per day of Orimulsion. The net heat rate was 8,600 BTU per kilowatt-hour and sulfur recovery was at 99 percent.

This case reflects early 1991 GE 7F performance ratings. This same module with current 7F ratings would produce in excess of 500 megawatts. In addition, Texaco has computed a 7F based case with an integrated oxygen plant, deriving a heat rate of 8,300 BTU per kilowatt-hour.

Capital Cost

Fluor Daniel has developed a capital cost for the Orimulsion IGCC plant described above. The estimated cost on a total facility basis, excluding owner's costs, was calculated to amount to $1,232 per kilowatt-hour.

Under the same conditions, the estimated cost of a Texaco coal based IGCC plant came to $1,475 per kilowatt-hour. This difference in capital would translate to a difference in the cost of electricity of $0.005 to $0.01 per kilowatt-hour.

###

UTAH TAR SANDS SHOW POTENTIAL FOR HIGH DENSITY JET FUELS

C.H. Tsai, et al., of the University of Utah, discussed the "Potential of Jet Fuels from Utah Tar Sands Bitumens and Bitumen-Derived Liquids" at the Symposium on Structure of Jet Fuels III held in San Francisco, California in April. The authors concluded that jet fuel boiling range fractions obtained from native Utah bitumens show potential for use as high density jet fuel after mild hydrotreatment. The current work has emphasized hydroprocessing of the bitumen-derived liquid that was produced during the pyrolysis of Whiterocks tar sand in a fluidized-bed reactor. Significant yields of a jet fuel boiling range fraction (20 to 40 weight percent) can be obtained from single-stage hydrotreating of the bitumen-derived liquid. These jet fuel fractions meet most of the Jet A specifications; however, they may require mild hydrofinishing to reduce the nitrogen and sulfur contents.

Jet Fuel Potential of the IBP-650°F Fractions of the Native Bitumens

The analyses of two potential jet fuel boiling range fractions (IBP-650°F) from the native bitumens from the Whiterocks and Asphalt Ridge tar sand deposits are reported in Table 1. The properties of the fractions indicate their potential for use as high density advanced jet fuels. Although the heat of combustion (per unit mass) of these fractions is slightly lower than the specification for Jet A, it can be improved by hydrotreating at mild conditions which will lead to an increase in hydrogen content and the atomic hydrogen/carbon ratio.

Jet Fuel Potential of Bitumen-Derived Liquids

The properties of jet fuel boiling range material distilled from the hydrotreated total liquid products produced from the bitumen-derived liquid are summarized in Table 2. It exhibits potential for use as jet fuels. Jet fuels, derived from Utah tar sands, could be used as high energy-density jet fuels due to the high concentration of naphthenic species indicated in Table 2.

Unlike the jet fuel boiling range fractions from the native bitumens which contain mainly alkyl-decalins and alkyl-tetralins, the chemical constituents of jet fuel boiling range fractions from the hydrotreated bitumen-derived liquid are normal and branched alkanes, fragmented polyalkyl-cyclohexanes, unsubstituted and substituted decalins, hydrindans, indans, and tetralins.

The IBP-650°F jet fuel boiling range fractions reported in Table 1 and the 400 to 650°F fractions reported in Table 2
TABLE 1

PROPERTIES OF THE NATIVE BITUMENS AND JET FUEL FRACTIONS (IBP-650°F)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity, °API</td>
<td>12.2</td>
<td>25.9</td>
<td>11.9</td>
<td>26.2</td>
</tr>
<tr>
<td>Specific Gravity</td>
<td>0.985</td>
<td>0.8989</td>
<td>0.9871</td>
<td>0.8970</td>
</tr>
<tr>
<td>Elemental Analysis</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C, wt%</td>
<td>86.8</td>
<td>86.5</td>
<td>85.7</td>
<td>86.5</td>
</tr>
<tr>
<td>H, wt%</td>
<td>11.6</td>
<td>12.3</td>
<td>11.0</td>
<td>12.4</td>
</tr>
<tr>
<td>N, wt%</td>
<td>1.1</td>
<td>0.2</td>
<td>1.0</td>
<td>0.1</td>
</tr>
<tr>
<td>S, wt%</td>
<td>0.4</td>
<td>0.4</td>
<td>0.5</td>
<td>0.2</td>
</tr>
<tr>
<td>O, wt%</td>
<td>1.1</td>
<td>0.6</td>
<td>1.8</td>
<td>0.8</td>
</tr>
<tr>
<td>H/C Atomic Ratio</td>
<td>1.62</td>
<td>1.70</td>
<td>1.53</td>
<td>1.72</td>
</tr>
<tr>
<td>Net Heat of Combustion</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BTU/lb</td>
<td>17,700</td>
<td>18,070</td>
<td>17,620</td>
<td>18,110</td>
</tr>
<tr>
<td>BTU/gal</td>
<td>145,500</td>
<td>135,500</td>
<td>145,100</td>
<td>135,500</td>
</tr>
<tr>
<td>Freeze Point, °F</td>
<td>-</td>
<td>&lt;-89</td>
<td>-</td>
<td>&lt;-89</td>
</tr>
</tbody>
</table>

originates from the same starting material; however, they differ in their properties because of their different processing histories.

A high quality jet fuel boiling range fraction can be distilled from the native bitumen in low yield. The yield of the jet fuel fraction from bitumens can be increased by pyrolysis of the tar sand followed by hydrotreating of the produced liquid product; however, the authors say, this is accomplished at the expense of producing a jet fuel boiling range fraction having a higher freeze point.

MOLECULAR TRANSFORMATIONS IN PYROLYSIS/HYDROTREATING OF OIL SANDS EXPLORED

F.V. Hanson, et al., of the Department of Fuels Engineering at the University of Utah have explored the molecular transformations that occurred in the processing sequence: pyrolysis of mined oil sand ore from Utah's Uinta Basin in a fluidized bed followed by hydrotreating of the bitumen-derived liquid. Their findings were presented at the American Chemical Society's Fuel Chemistry Division symposium held in San Francisco, California in April.

Fluidized Bed Pyrolysis System

The bitumen-derived liquid used in the hydrotreating study was produced from Whiterocks tar sand ore in a large diameter fluidized bed pyrolysis reactor. The reactor temperature ranged from 773 to 813°K, and the average feed sand retention time was 17.2 minutes.

Hydrotreater Process Unit

The base case operating conditions for the hydrotreating study were as follows: reaction temperature, 619°K; total reactor-pressure, 13.7 MPa, and hydrogen-to-hydrocarbon feed ratio, 5,000 standard cubic feet per barrel. The API gravity of the total liquid product was constant at 23.2°API after the reactor was onstream for 94 hours. A series of experiments were conducted in which the system was operated in a cyclic mode for approximately 1,000 hours. The total liquid product from each experiment was collected for analysis.

A Unocal quadralobe Ni/Mo/Al₂O₃ hydrodenitrogenation (HDN) catalyst was used in this study.

Results

According to the paper, the bitumen-derived liquid was significantly upgraded relative to the native bitumen: 19.1°API versus 11.9°API; a viscosity of 85.4 centipoise at 289°K, ver-
### TABLE 2

**JET FUEL FROM HYDROTREATED BITUMEN-DERIVED LIQUID**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>IBP-650°F Product</td>
<td></td>
</tr>
<tr>
<td>API Gravity</td>
<td>35.6</td>
</tr>
<tr>
<td>Specific Gravity</td>
<td>0.8466</td>
</tr>
<tr>
<td>Carbon, wt%</td>
<td>86.5</td>
</tr>
<tr>
<td>Hydrogen, wt%</td>
<td>13.5</td>
</tr>
<tr>
<td>H/C Atomic Ratio</td>
<td>1.87</td>
</tr>
<tr>
<td>Aniline Point, °F</td>
<td>137</td>
</tr>
<tr>
<td>Freeze Point, °F</td>
<td>-42</td>
</tr>
<tr>
<td>Viscosity, cSt@100°F</td>
<td>2.36</td>
</tr>
<tr>
<td>Cetane Index (ASTM D976-80)</td>
<td>45.5</td>
</tr>
<tr>
<td>BTU/lb</td>
<td>18,390</td>
</tr>
<tr>
<td>BTU/gal</td>
<td>130,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TBP Distillation, °F (ASTM D86)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>IBP/5</td>
<td>312/359</td>
</tr>
<tr>
<td>10/30</td>
<td>385/443</td>
</tr>
<tr>
<td>50</td>
<td>489</td>
</tr>
<tr>
<td>70/90</td>
<td>528/575</td>
</tr>
<tr>
<td>95/end point</td>
<td>596/604</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Carbon Distribution, wt% (ASTM D3238)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>C</td>
<td>42.5</td>
</tr>
<tr>
<td>Cₙ</td>
<td>38.5</td>
</tr>
<tr>
<td>Cₐ</td>
<td>19.0</td>
</tr>
</tbody>
</table>

The atomic hydrogen-to-carbon (H/C) ratio of the bitumen-derived liquid was lower than that of the native bitumen. This reduction was related to dealkylation reactions during pyrolysis which resulted in the production of a more aromatic hydrocarbon liquid.

Major compound types found in the 1,000°F minus fraction of the Whiterocks bitumen were substituted and unsubstituted cyclohexanes, benzenes, decalins, tetrals, naphthenes, perhydrophenanthrenes (tricyclic terpanes), octahydrophenanthrenes, tetrahydrophenanthrenes, phenantrenes, phenyl (cyclohexyl) alkanes, indan (cyclohexyl) alkanes, perhydrochrysenes (17,21-secohopanes), steranes (C_{27} to C_{31}), hopanes (C_{27} to C_{35}) and traces of paraffins. Heterocyclics such as benzofuran, indoles, quinolines, carbazoles and tricyclic and pentacyclic carboxylic acids were also detected.

Basically, the compound types identified in the Whiterocks bitumen-derived liquid were similar to those identified in the volatile fraction of the bitumen. Several additional compound types were also identified. The hydrotreated bitumen-derived liquid consisted primarily of saturated compounds, such as alkanes (normal and branched) and cycloalkanes (1 to 5 rings). It also contained low concentrations of aromatic compounds which were predominantly mono-aromatics.

The task of identifying the thermal reaction pathways in bitumen pyrolysis was difficult due to the complexity of the native bitumen. However, several pathways were rationalized including cleavage of long side chains, dehydrogenation, polymerization and condensation, and decarboxylation.

Hydrogen was produced during the pyrolysis of oil sand. The formation of hydrogen was believed to have occurred via a gas phase reaction, coincident with light oils production and a solid reaction, associated with the formation of the carbonaceous residue on the sand grains.

Small amounts of carbon dioxide were detected in the produced gases during pyrolysis of the Whiterocks oil sand. It was presumed that the CO₂ was produced by thermal decomposition of carboxylic acid functional groups present in the native bitumen.

Hydrogenation, hydrogenolysis and heteroatom removal were the principal reactions which occurred in the hydrotreater. The absence of olefins in the hydrotreated products and the heat released in the inlet region of the catalyst bed suggested that hydrogenation of olefinic bonds occurred readily during hydropyrolysis. The predominance of hydroaromatic species in the total liquid product indicated that polycyclic aromatics underwent partial hydrogenation.

### BOREHOLE MINING PROVES INFEASIBLE AT COLD LAKE

The Cold Lake reservoir (Figure 1) holds an estimated 40 billion cubic meters of bitumen, and accounts for almost 14,000 cubic meters per day of bitumen production. The reservoir is approximately 40 meters in thickness at a depth of about 450 meters.

As part of an ongoing research and development effort for new, low-cost in situ recovery technologies for oil sands, Imperial Oil studied the feasibility of hydraulically mining deep oil sands. The pilot projects were discussed by S.D. Daniel, et al., at the Ninth Annual Heavy Oil and Oil Sands Technical Symposium held in March. Daniel concluded that hydraulic mining was not feasible for this site.
While conducting a well repair program in early 1989, Imperial identified an alternate bitumen recovery process. A surface discharge of bitumen was discovered near an abandoned well at Cold Lake. The bitumen had been displaced up the abandoned hole by adjacent steaming operations. To plug the abandoned well, a relief well was drilled into the Clearwater Formation so that its bottom was within one meter of the existing well. A water jetting tool was lowered into the relief well to cut out a thin window in the casing and create a cavity to place cement. While jetting, large volumes of oil and sand accumulated in the return tank. The sand, bitumen and water were observed to separate as they flowed into the tank. Consequently, Imperial initiated a research program to explore the potential of hydraulically mining oil sands as a more economical alternative to steam based processes (Figure 2).

Geology and Reservoir Properties

The Clearwater Shale is composed of about 1 meter of dark marine 100 percent shale (specific gravity 2.2) that grades upward into 3 to 4 meters of silty shale. The shale layer is a competent seal for hydrocarbon accumulations (bitumen and gas). However, this layer has not been deeply buried and therefore can easily part along its bedding planes.

The first field pilot was conducted in late 1990. The objectives of the 1990 pilot were to:

- Validate the borehole mining concept
- Determine the produced slurry characteristics
- Determine the residual bitumen content in the produced sand

The borehole mining concept was tested under various injection rates, nozzle sizes and gaps between the nozzles and the circulating string. The downhole slurry, which was created as a result of the jetting action, was forced to the surface through the annulus between the circulating and jetting string by virtue of the cavern pressure. The slurry was then transported to the open tanks via a surface pipeline where oil froth formed on the top and sand settled to the bottom. The froth was collected with a vacuum truck, free water was drawn off with the blender and recirculated, and the sand
was removed with a backhoe. The sonar log data obtained at the end of the experiment showed a cavern volume of 15 cubic meters.

1990 Pilot Results

The 1990 pilot was of short duration, with a total jetting time of 14 hours, and therefore the conclusions are based on limited data. The 1990 pilot demonstrated that:

- The hydraulic mining concept works and oil sands mining rates up to 50 tonnes per hour can be achieved, and production rates on the order of 15 tonnes per hour can be sustained.

- For the wellbore used, at 15 tonnes per hour the energy consumption is approximately 50 hydraulic horsepower per tonne of oil sands per hour produced, and at 50 tonnes per hour the energy consumption is approximately 30 hydraulic horsepower per tonne per hour produced.

- The produced sand contained less than 1 percent by weight bitumen, indicating a bitumen separation efficiency greater than 90 percent.

- The produced bitumen froth contained 40 percent water and 20 percent solids by weight.

- The produced water contained less than 2 percent solids and about 0.5 percent bitumen by weight.

To achieve a cavern of 100,000 cubic meters, the shale at the interface of the Clearwater and Grand Rapids formations would have to sustain a roof with a span in excess of 80 meters. Furthermore, it was required to remain stable for about 10 months to provide sufficient time to mine and backfill the cavern. The susceptibility of the shale to swelling in the presence of water, and its inherent structural weakness raised increasing concerns that it would fail prematurely and hence destroy the integrity of the cavern.

Thus, the primary objective of the 1991 pilot was to create a cavern immediately below the shale in order to expose a span in excess of 5 meters, and to monitor its stability over a period of several months. During this period the pressure in the cavern would be kept above the ambient pore pressure in the reservoir (approximately 3 megapascals) in order to ensure that there was a resultant force supporting the roof. The fluid used for the test was produced water from Cold Lake CSS operations. This was used because it had been demonstrated to have a lower swelling effect on the shale than fresh water.

During the course of creating a cavern to test the integrity of a shale roof, other aspects of the borehole mining process were to be investigated. These objectives included:

- Establish the stand-off distance when jetting at a velocity of 200 meters per second and a flow rate of 2.5 cubic meters per minute
- Determine the angle of the cavern walls
- Demonstrate improved nozzle design
- Ascertain oil sands mining rate
- Establish mining efficiency

To highlight the project, the third sonar log indicated that the test objective had been achieved. A cavern with a volume of 172 cubic meters had formed, with a flat roof at the shale/oil sands interface. The roof span was between 6 meters and 8 meters. Jetting continued with the high velocity jets for a further 2 days, until the span on the shale roof was 8 to 10 meters.

A gamma log run 12 days later indicated that the shale had started to fail at a rate of about 1 meter per week. Another sonar log showed that the cavern had continued to grow vertically upwards across its entire width and that the sloughed material had expanded to fill the original cavern in addition to some of the space previously occupied by the shale roof. The cavern volume was calculated to be 77 cubic meters. At this point, the pilot was aborted and it was decided to fill the cavern with fracturing sand to prevent further propagation of the roof failure. Fifty cubic meters of 1640 fracturing sand were circulated into the cavern. A gamma log run a month later confirmed that the roof had become stable.

1991 Results and Conclusions

The test demonstrated conclusively that the shale will not provide a stable roof for more than a few days.

No delays were experienced because of problems with the nozzles, and low velocity jets can be expected to last for 6 months.

The maximum production rate achieved in the test was 50 tonnes per hour with a sustained average of 30 tonnes per hour. The target of a sustained rate of 50 tonnes per hour appears feasible.

In order to achieve a reasonable production rate it was necessary to use the high velocity jets with their corresponding high energy input. With the low velocity jets a reasonable slurry density was never achieved. During the 1991 test an efficiency of 50 hydraulic horsepower per tonne per hour of oil sands produced was achieved on a sustained basis.

A stand-off distance of 2.5 meters was achieved with a jetting velocity of 200 meters per second and a flow rate of 2.5 cubic meters per minute. This was greater than expected.
Based on the sonar logs, the wall angle can be estimated to be anywhere between 63° and 84° from the horizontal. This variation may be caused by the localized stress orientation within the reservoir. It should be understood that the height of the cavern achieved in this test may have been insufficient for the walls to slough to their ultimate angle.

During the test a leak-off rate of 0.15 cubic meters per minute was experienced at a cavern pressure of 8 megapascals. This leak-off is directly proportional to cavern surface area, but inversely proportional to mining duration. Theoretical studies indicate that the rate would approach an asymptotic value of 0.1 cubic meters per minute after 10 to 15 days of mining.

#####
RECENT PUBLICATIONS

The following papers were presented at the American Chemical Society, Division of Fuel Chemistry meeting held in San Francisco, California, April 5-10:

Hanson, F.V., et al., "Molecular Transformations in the Processing Sequence Pyrolysis-Hydrotreating with Utah Oil Sands"

Deo, M.D., et al., "The Effect of Cosolubilizing Lighter Components on the Asphaltene Content of Heavy Oils"

Storm, D.A., et al., "Small Angle X-Ray Scattering Study of Asphaltenes"

Sheu, E.Y., et al., "Colloidal Structure of Vacuum Residue in Solvents"

Velasco, L.E., et al., "Process for the Production of Petroleum Tar Pitch for Anode Manufacturing"

The following paper was presented at the Symposium on "Structure of Jet Fuels III" at the American Chemical Society meeting held in San Francisco, California, April 5-10:

Tsai, C.H., et al., "Potential of Jet Fuels from Utah Tar Sand Bitumens and Bitumen-Derived Liquids"

The following papers were presented at the Ninth Annual Heavy Oil and Oil Sands Technical Symposium held in Calgary, Alberta, Canada, March 11:

Sharpe, et al., "Cold Lake Borehole Mining"

Butler, "Steam-Assisted Gravity Drainage—Concept, Development, Performance, Future"


Wollen, et al., "Thermal Well Pumping Developments"

Browne, et al., "Downhole Emulsification—Viscosity Reduction Increases Production"

Campbell, "Recirculation Systems for Heavy Oil Primary Production in the Lindbergh Oil Sands"

Woo, et al., "Role of Emulsions in Heavy Oil Production"

Loughead, et al., "Lloydminster Heavy Oil Production—Why so Unusual?"

Sametz, "Primary Case Study Cactus Lake McLaren: Exploitation Utilizing Horizontal Drilling"

Fontaine, et al., "Development of Pelican Lake Area Using Horizontal Well Technology"

The following appeared in The Journal of Canadian Petroleum Technology, April 1992:

Kokal, S.L., et al., "Measurement and Correlation of Asphaltene Precipitation from Heavy Oils by Gas Injection"

Butler, R.M., "Gravity Drainage to Horizontal Wells"

The following appeared in Energy & Fuels, March/April 1992:

Bukka, K., et al., "Fractionation and Characterization of Whiterocks Tar Sands Bitumen"
"Partial Oxidation Process," Michael Dach, Robert Stellaccio - Inventors, United States Patent Number 5,087,271, February 11, 1992. This process pertains to achieving high on-stream time and maintaining the temperature and composition of the raw effluent gas stream from a partial oxidation gas generator being fed simultaneously with a stream of gaseous fuel and separate stream of liquid hydrocarbonaceous fuel. Two parallel oxygen streams equipped with flow transmitters and control valves are used to supply the oxygen associated with two separate and different fuel streams. Each stream of oxygen is controlled by an O2/fuel ratio control so that if the flow rate of either stream of fuel or its related oxygen stream changes, the oxygen/carbon atomic ratio of the remaining O2 and fuel stream in the gasifier is maintained at a desired value. Further, if either fuel flow is stopped, its associated O2 flow will stop, but the remaining fuel stream and its associated O2 stream will continue to flow at the same rate with no change in the oxygen/fuel weight ratio. Complete shut down of the unit is thereby avoided. The quick raising of reactor temperatures to unsafe levels due to excess oxygen that occurs when one of the fuel streams is lost is thereby prevented.

"Method for Processing Heavy Crude Oils," Roldofo Barba, Roberto Lorenzo, Oscar Mendi, Leonardo Olmos, Rene Perez, Carlos Sanchez, Abel Tovar - Inventors, Instituto Mexicano Del Petroleo, United States Patent Number 5,089,114, February 18, 1992. A method for processing heavy crude oils comprising a) atmospheric distillation of heavy crude oil having a high content of metals, asphaltenes and sulfur; b) solvent extraction of the atmospheric distillation residue to obtain an extract with characteristics equivalent to those which an atmospheric residue derived from light crude oil and a raffinate fraction, solid at ambient conditions, in which are concentrated the asphaltenes, metals and sulfur present in the original crude oil; c) vacuum distillation of the deasphalted extract, obtaining a light fraction or gas oils with characteristics adequate to be subjected to a secondary conversion process, plus a bottoms fraction or vacuum residue; d) treatment of the vacuum gas oils in a conversion stage and e) subjecting the bottoms of raffinate from the extraction stage to a metallurgical process, in admixture with cokeable coal and coke fines to production of metallurgical coke.

"In Situ Tuned Microwave Oil Extraction Process," Anoosh Kiamanesh - Inventor, United States Patent Number 5,082,054, January 21, 1992. A method of creating a protocol for oil extraction or for enhancing oil extraction from oil reservoirs. A process of devising and applying a customized electromagnetic irradiation protocol to individual reservoirs. Reservoir samples are tested to determine their content, molecular resonance frequencies and the effects of electromagnetic field on their compounds. Electromagnetic field frequencies, intensities, wave forms and durations necessary to heat and/or crack individual molecules and produce plasma torches is determined. Equipment are selected and installed according to the results of the laboratory tests and the geophysics of the mine. Dielectric constant of the formation is reduced by draining the water and drying it with electromagnetic energy. A combination of the effects of microwave flooding, plasma torch activation, molecular cracking and selective heating are used to heat the oil within the reservoir, by controlling frequency, intensity, duration, direction and wave form of the electromagnetic field. Conditions of the reservoir are continuously monitored during production to act as feedback for modification of the irradiation protocol.
STATUS OF OIL SANDS PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since March 1992)

ASPHALT FROM TAR SANDS - James W. Burger and Associates, Inc. (T-5)

J. W. Burger and Associates, Inc. (JWBA) is developing a project for commercialization of Utah Tar Sands. The product of the initial venture will be asphalts and high value commodity products. The project contemplates a surface mine and water extraction of bitumen followed by clean-up and treatment of bitumen to manufacture specification asphaltic products. JWBA has secured rights to patented technology developed at the University of Utah for extraction and recovery of bitumen from mined ore.

In 1990, JWBA completed a $550,000 R&D program for development of technology and assessment of markets, resources and economics for asphalt production.

Under this program funded by the U.S. DOE SBIR program, a 100-300 pound per hour PDU was designed and constructed. The unit has been operated to determine the effect of process variables and kinetic parameters. Recoveries of greater than 97 percent have been experienced. The unit has been operated to produce gallon quantities of asphalt for testing and inspection. A field demonstration unit of 200 barrels per day has been designed and costed. Results show a strong potential for profitability at 1990 prices and costs.

All candidate sites in the Uinta Basin of Utah are currently under consideration for development including Asphalt Ridge, P.R. Spring, Sunnyside and White Rocks. Unknown resource quality tends to increase required investment hurdle rates, however, and these factors must be offset by higher product prices. In 1990 JWBA initiated a program for value-added research to extract high value commodity and specialty products from tar sand bitumen. This program was initiated with an additional $50,000 in funding from DOE.

The commercialization plan calls for completion of research in 1992, construction and operation of a field demonstration plant by 1994 and commercial operations by 1996. The schedule is both technically realistic and financially feasible, says JWBA.

Project Cost:

- Research and Development: $15 million
- Demonstration project: $10 million
- Commercial Facility: $135 million

BI-PROVINCIAL UPGRADER - Husky Oil Operations Ltd. (T-10)

Husky Oil is proceeding with the design and construction of a heavy oil upgrader to be located near the Alberta/Saskatchewan border at Wilton, near Lloydminster, Saskatchewan. The facility will be designed to process 46,000 barrels per day of heavy oil and bitumen from the Lloydminster and Cold Lake deposits. The primary upgrading technology to be used at the upgrader will be H-Oil ebullated bed hydrocracking followed by delayed coking of the hydrocracker residual. The output will be 46,000 barrels per day of high quality synthetic crude oil.

Engineering and design of the plant was initiated in June 1984 under terms of an agreement between Husky Oil Operations Ltd. and the governments of Canada, Alberta, and Saskatchewan.

Phase 1 of the project (design engineering and preparation of control estimate) was completed in March 1987. Detailed engineering and construction were placed on hold pending negotiation of fiscal arrangements with the governments of Canada, Alberta and Saskatchewan.

In September, 1988, however, Husky and the governments of Canada, Alberta and Saskatchewan, signed a binding joint venture agreement to finance and build the Bi-Provincial Upgrader. Project completion is targeted for late 1992.

In February, 1989 the Bi-Provincial Upgrader Joint Venture announced the award of $120 million in engineering contracts, with work to start immediately and be in full swing by April, 1989.

Site preparation has been completed. The award of major civil contracts began early in 1990. Major mechanical contracts were started in the 3rd quarter 1990. The construction management team moved their operations to site offices in March, 1990. The construction force was expected to peak at 2,800 persons by the 3rd quarter 1991.

Engineering for the project is nearly complete. Well over half of the equipment is already on site. Half of the process could be ready for early startup in summer 1992. The second half is scheduled for startup in the third quarter of 1992. Cost overruns have required an additional investment of $175 million in the project.

Project Cost: Upgrader Facility estimated at C$1.4 billion
The Solv-Ex Bitumount Project will be a phased development of an open pit mine and an extraction plant using Solv-Ex's process for recovery of bitumen and metals.

Solv-Ex will use a naphtha solvent to boost the power of hot water to separate oil from sand. The increased efficiency of the process increases oil yield and also allows metals such as gold, silver and titanium to be extracted from the very clean sand. Analyses of the pilot plant tailings (after bitumen extraction) showed that these minerals are readily recoverable.

A Solv-Ex pilot plant, located in Albuquerque, New Mexico, can process up to 72 tons of oil sands per day. It can also produce up to 25 barrels of bitumen per day, depending on the grade of oil sands processed. The quantity of bitumen recoverable from tar sands depends on its bitumen content, which typically ranges from 4 to 12 percent.

In an 8-month test program, Solv-Ex processed approximately 1,000 tons of Athabasca tar sands material in process runs of low (6 percent of bitumen), average (8 to 10 percent), and high (12 to 14 percent) grade oil sands through the pilot plant. The test material was procured from a pit centrally located in the oil sands deposits on which the Bitumount Lease is located. Average percentage of bitumen recovered for the low, average and high grade sands were 75%, 90% and 95%, respectively.

In February, 1989, a viable processing flowsheet was finalized which not only recovers the originally targeted gold, silver and titanium values but also the alumina values contained in the resource. Synthetic crude oil would represent about 25 percent of the potential mineral values recoverable from the Bitumount Lease.

The results of this work indicate that the first module could be a single-train plant, much smaller than the 10,000 barrels per calendar day plant originally envisaged. The optimum size will be determined in the preconstruction feasibility study and this module is estimated to cost not more than C$200 million.

The Bitumount lease covers 5,874 acres north of Port McMurray, Alberta. Bitumen reserves on the lease are estimated at 1.4 billion barrels.

Solv-Ex is looking for potential financial partners to expand the project. The company plans to construct a modular Lease Evaluation Unit in Alberta at an estimated cost of $12 million.

The Burnt Lake in situ heavy oil project is located on the Burnt Lake property in the southern portion of the Primrose Range in northeast Alberta. Initial production levels will average 12,500 barrels per day.

According to the companies, the Burnt Lake project is a milestone because it will be the first commercial development of these heavy oil resources on the Primrose Range. This will require close cooperation with Canada's military.

The multi-phase Burnt Lake project, which was proposed to use cyclic steam stimulation, was put on hold in 1986 due to low oil prices, then revived in 1987. The project as of early 1989 was again halted.

A pilot was initiated in 1990 to test the cold flow production technique whereby the bitumen is produced together with some sand using a progressive cavity pump. Initial results were encouraging. Since then, twelve wells have been put on production. The pilot will be continued to obtain long term results and the productivity of the reservoir on a regional basis.

If successful, the cold flow production process may replace the cyclic steam stimulation process for commercial development.

Burnt Lake is estimated to contain over 300 million barrels of recoverable heavy oil.

In September 1983 the Alberta Energy Resources Conservation Board (AERCB) granted Esso Resources Canada Ltd. approval to proceed with construction of the first two phases of commercial development on Esso's oil sands leases at Cold Lake. Subsequent approval for Phases 3 and 4 was granted in June 1984 and for Phases 5 and 6 in May 1985.

Cyclic steam stimulation is being used to recover the bitumen. Processing equipment consists of a water treatment and steam generation plant and a treatment plant which separates produced fluids into bitumen, associated gas and water. Plant design allows for all produced water to be recycled.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

Shipments of diluted bitumen from Phases 1 and 2 started in July 1985, augmented by Phases 3 and 4 in October, 1985 and Phases 5 and 6 in May, 1986. During 1987, commercial bitumen production at Cold Lake averaged 60,000 barrels per day. Production in early 1988 reached 85,000 barrels per day. A debottlenecking of the first six phases added 19,000 barrels per day in 1988, at a cost of $45 million. Production in 1990 averaged 90,000 barrels per day.

The AERCB approved Esso’s application to add Phases 7 through 10, which could eventually add another 44,000 barrels per day. All construction was essentially completed in 1988 on the central processing plant and the field facilities for Phases 7 and 8 at a cost of $320 million. In December 1990, Esso announced plans to put Phases 7 and 8 into operation and begin steaming in March 1991. Startup costs will be approximately $25 million. The development is expected to add 14,500 barrels per day of bitumen production and build up to 20,000 barrels per day. In February 1991, Esso made a decision to delay the startup of Phases 7 and 8. If market conditions improve, steaming operations could begin again. In March and April of 1991, Esso shut in 15,000 barrels per day of bitumen production due to unfavorable market conditions.

Project Cost: Approximately $770 million for first ten phases

DAPHNE PROJECT -- Petro-Canada (T-60)

Petro-Canada is studying a tar sands mining/surface extraction project to be located on the Daphne leases 65 kilometers north of Fort McMurray, Alberta. The proposed project would produce 75,000 barrels per day. To date over 350 core holes have been drilled at the site to better define the resource.

Currently, the project has been suspended pending further notice.

DIATOMACEOUS EARTH PROJECT -- Texaco Inc. (T-70)

Texaco placed its Diatomite Project, located at McKittrick in California’s Kern County, in a standby condition in 1985, to be reactivated when conditions in the industry dictate. In 1991 the company is initiating steps to re-evaluate the technology needed to recover the oil and to evaluate the environmental compliance requirements for a commercial plant. Consideration will be given to restarting the Lurgi pilot unit.

The Company estimates that the Project could yield in excess of 300 million barrels of 21 to 23 degrees API oil from the oil-bearing diatomite deposits which lie at depths up to 1,200 feet. The deposits will be recovered by open pit mining and back filling techniques.

Project Cost: Undetermined

ELECTROMAGNETIC WELL STIMULATION PROCESS -- Uentech Corporation, A Subsidiary of Electromagnetic Oil Recovery, Inc. (T-80)

Electromagnetic Oil Recovery Inc. (EOR), formerly Oil Recovery Systems (ORS) Corporation, through its subsidiary, Uentech Corporation, sponsored research and development at the Illinois Institute of Technology Research Institute (IITRI) on a single-wellbore electromagnetic stimulation technique for heavy oil. The technique uses the well casing to induce an electromagnetic field in the oil-bearing formation. Both radio frequency and 60 cycle electric voltage are used. The radio frequency waves penetrate deeply into the formation while the 60 cycle current creates resistive heating.

The first field test with a commercial well, initially producing about 20 barrels per day, was put into production in December 1985 in Texas, on property owned by Coastal Oil and Gas Corporation. In June 1986, ORS received permits from the Alberta Energy Resources Conservation Board, and stimulation started in a well in the Lloydminster area in Alberta, Canada. This well was drilled on a farmout from Husky Oil in the Wildmere Field. Primary production continued for about 60 days, during which the well produced about 6 barrels per day of 11 degrees API heavy oil. The well was then shut down to allow installation of the ORS electromagnetic stimulation unit. After power was turned on and pumping resumed on June 10, a sustained production of 20 barrels per day was achieved over the following 30 days. The economic parameters of the operation were within the range expected, and process energy costs have been demonstrated at around $1/bbl, according to ORS.

Additional projects under way with EOR, Inc.’s technology include:

Canada Northwest Energy Ltd. installed an electromagnetic heating system within a well located near Lashburn, Saskatchewan in February 1989. Production averaged triple the production rate which existed before installation of the EOR system. Pan Canadian Petroleum Co., Ltd. has had a project ongoing since late 1990, with encouraging results for this heavy oil application. In Utah, an EOR system was installed in a well owned by GHP Corporation during December 1991. The system was designed to overcome production problems associated with an oil containing a large amount of paraffin. Also in Utah, EOR has been contracted by
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

Coors Energy company to test the process in a field which experiences production problems associated with paraffinic oil. In Wyoming, Marathon Oil Company installed the EOR equipment within a well near Cody, Wyoming in late 1990. EOR was contracted by Shell to provide equipment and services to utilize the technology within a well in the Schoonebeck field of the Netherlands. The project resulted in EOR signing a contract for additional work for another Shell affiliate, Petroleum Development Oman. For Lagoven, EOR has been contracted to provide equipment and services for two wells in the Jobo Field of Venezuela, with startup scheduled for late summer of 1992. In Indonesia, a project is pending with Pertamina for a deep well which experiences paraffin related production problems. In Brazil, EOR's project is slowly expanding. Currently four additional wells have been equipped with the EOR system with positive results for Petrobras.

Project Cost: Not disclosed

ELK POINT PROJECT — Amoco Canada Petroleum Company, Limited. (T-90)

The Elk Point Project area is located approximately 165 kilometers east of Edmonton, Alberta. Amoco Canada holds a 100 percent working interest in 6,600 hectares of oil sands leases in the area. The Phase 1 Thermal Project is located in the NW 1/4 of Section 28, Township 55, Range 6 West of the 4th Meridian. The primary oil sands targets in the area are the Lower Cummings and Clearwater sands of the Mannville Group. Additional oil sands potential is indicated in other Mannville zones including the Colony and the Sparky.

Oil production from current wells at Amoco’s Elk Point field totals 1,550 cubic meters per day.

Amoco Canada has several development phases of the Elk Point Project. Phase 1 of the project, which is now complete, involved the drilling, construction, and operation of a 13-well Thermal Project (one, totally enclosed 5-spot pattern), a continuation of field delineation and development drilling and the construction of a product cleaning facility adjacent to the Thermal Project. The delineation and development wells are drilled on a 16.19 hectare spacing and are cold produced during Phase 1.

Construction of the Phase 1 Thermal Project and cleaning facility was initiated in May 1985. The cleaning facility has been operational since October 1985. Cyclic Steam injection into the 13-well project was initiated in July, 1987 with continuous steam injection commencing on April 20, 1989. Continuous steam injection was discontinued in May 1990 and the pilot was shut in.

In February, 1987, Amoco Canada received approval from the Energy Conservation Board to expand the development of sections 28 and 29. To begin this expansion, Amoco drilled 34 wells in the north half of section 29 in 1987-88, using conventional and slant drilling methods. Pad facilities construction occurred in 1988. A further 24 delineation wells were drilled in 1989 and 22 wells were drilled in 1990.

Future drilling at Elk Point is dependent on Phase 2 approval of the project. Phase 2 will continue to focus on primary production development and will allow for further infill drilling in the entire project area in all zones within the Mannville group. Some limited cyclic steaming is planned in future years. Amoco’s application for Phase 2 is continuing through the application review and public consultation process in 1992.

Project Cost: Phase 1 - $50 Million (Canadian)

ELK POINT OIL SANDS PROJECT — PanCanadian Petroleum Limited (T-100)

PanCanadian received approval from the Alberta Energy Resources Conservation Board for Phase I of a proposed 3 phase commercial bitumen recovery project in August 1986.

The Phase I project involves development of primary and thermal recovery operations in the Lindbergh and Frog Lake sectors near ElkPoint in east-central Alberta. Phase I operations include development of 16 sections of land where 148 wells were drilled by the end of 1990.

PanCanadian expects Phase I recovery to average 3,000 barrels per day of bitumen, with peak production at 4,000 barrels per day. Tentative plans call for Phase II operations starting up in the mid 1990's with production to increase to 6,000 barrels per day. Phase III would go into operation in the late 1990's, and production would increase to 12,000 barrels per day.

Thus far, steam stimulation has been applied experimentally in three sections, and the results are being evaluated while a field test proceeds on a pilot steam flood process in one of these sections.

As of March 1991, low prices for heavy crude and lack of economics for expensive enhanced oil recovery methods have caused PanCanadian to delay Phase I plans. Meanwhile the company continues to streamline primary operations and to evaluate steam stimulation and experimental steam flood pilot results.

Project Cost: Phase 1 = C$60 Million to date
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

FOREST HILL PROJECT – Greenwich Oil Corporation (T-110)

Greenwich Oil Company is developing a project which entails modification of existing, and installation of additional, injection and production wells to produce approximately 1,750 barrels per day of 10 degrees API crude oil by a fire flooding technique utilizing injection of high concentration oxygen. Construction began in the third quarter 1985. Loan and price guarantees were requested from the United States Synthetic Fuels Corporation under the third solicitation. On August 21, 1985 the Board directed their staff to complete contract negotiations with Greenwich by September 13, 1985 for an award of up to $60 million. Contract was signed on September 24, 1985. Project has 21 injection wells taking 150 tons per day of 90 percent pure oxygen. The oil production rate reached 1,200 barrels per day.

On January 9, 1989, Greenwich riled for reorganization under Chapter 11 of the Bankruptcy Act. Oxygen injection was temporarily suspended but water is being injected into the burned-out sand zones to move unreacted oxygen through the combustion zone and to scavenge heat.

On January 2, 1990, Greenwich successfully implemented its Plan of Reorganization which had been approved by the Court in November 1990. Under the terms of an agreement with the United States Treasury, successor to the Synthetic Fuels Corporation, the commitment for loan guarantees and price support was terminated.

January 1992 production was 410 barrels of oil per day.

Project Cost: Estimated $42.5 million

LINDBERGH COMMERCIAL PROJECT – Amoco Canada Petroleum Company Ltd. (T-120)

Amoco (formerly Dome Petroleum) began a commercial project in the Lindbergh area that would initially cover five sections and was planned to be developed at a rate of one section per year for five years. It was to employ “huff-and-puff” steaming of wells drilled on 10 acre spacing, and would require capital investment of approximately $158 million (Canadian). The project was expected to encompass a period of 12 years. Due to the dramatic decline of oil prices, drilling on the first phase of the commercial project was halted, and has forced a delay in the proposed commercial thermal development.

The company has no immediate plans for steaming the wells to increase production because this process is uneconomic at current prices.

The current focus has been development and optimizing of primary production. In 1990, 26 wells on 40-acre spacing were drilled for primary production. Again, due to low heavy oil prices, some limited drilling will take place in 1991. Primary production from the project is now averaging 6,200 barrels per day.

Project Cost: $158 Million

LINDBERGH COMMERCIAL THERMAL RECOVERY PROJECT – Murphy Oil Company Ltd. (T-130)

Murphy Oil Company Ltd., has completed construction and startup of a 2,500 barrel per day commercial thermal recovery project in the Lindbergh area of Alberta. Project expansion to 10,000 barrels per day is planned over nine years, with a total project life of 30 years. The first phase construction of the commercial expansion involved the addition of 53 wells and construction of an oil plant, water plant, and water source intake and line from the North Saskatchewan River.

Murphy has been testing thermal recovery methods in a pilot project at Lindbergh since 1974. Based on its experience with the pilot project at Lindbergh, the company expects recovery rates in excess of 15 percent of the oil in place. Total production over the life of this project is expected to be in excess of 12 million cubic meters of heavy oil.

The project uses a huff-and-puff process with about two cycles per year on each well. Production is from the Lower Grand Rapids zone at a depth of 1,650 feet. Oil gravity is 11 degrees API, and oil viscosity at the reservoir temperature is 85,000 centipoise. The wells are directionally drilled outward from common pads, reducing the number of surface leases and roads required for the project.

The project was suspended for a year from September 1988 to August 1989 when three wells were steamed. The project returned to production on a limited basis in the last quarter of 1989. Initial results have been very encouraging, says Murphy, but an expansion to full capacity depends on heavy oil prices, market assessment, and operating costs.

Project Cost: $30 million (Canadian) initial capital cost
$12 million (Canadian) operating costs plus $12 million capital additions annually are anticipated
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

NEWGRADE HEAVY OIL UPGRADER — NewGrade Energy, Inc., a partnership of Consumers Co-Operative Refineries Ltd. and the Saskatchewan Government (T-140)

Construction and commissioning of the upgrader was completed in October, 1988. The official opening was held November 9, 1988. In 1989 the hydrogen plant experienced many shut downs and a fire, causing other problems down the line due to fluctuations. The problems with winterization, valves and metering systems were solved, however.

The refinery/upgrader combination has been running at 50,000 barrels per day of crude through the refinery itself. From that, 30,000 barrels per day of heavy resid bottoms are sent to the new Atmospheric Residual Desulfurization unit which performs primary upgrading. From there 12,000 barrels per day is being run through the Distillate Hydrotreater which improves the quality of the distillate fuel oil streams by adding hydrogen.

The 50,000 barrels per day heavy oil upgrading project was originally announced in August 1983.

Consumers' Co-Operative Refineries provided 5 percent of the costs as equity, plus the existing refinery, while the provincial government provided 15 percent. The federal government and the Saskatchewan government provided loan guarantees for 80 percent of the costs as debt.

NewGrade selected process technology licensed by Union Oil of California for the upgrader. The integrated facility is capable of producing a full slate of refined products or alternately 50,000 barrels per day of upgraded crude oil or as will be the initial case, some combination of these two scenarios.

Current operations include the processing of 50,000 barrels per day of heavy Saskatchewan crude with approximately 70 percent (35,000 barrels per day) being converted to a full range of refined petroleum products and the remaining 30 percent (15,000 barrels per day) being sold as synthetic crude.

Project Cost: $700 million

ORIMULSION PROJECT — Petroleos de Venezuela SA (PDVSA) and Veba Oel AG (T-145)

Venezuela's state-owned oil company, Petroleos de Venezuela SA (PDVSA), and Germany's Veba Oel AG plan to develop the heavy crude and bitumen reserves in the Orinoco Belt in eastern Venezuela. The two companies conducted a feasibility study to construct a facility capable of upgrading 80,000 barrels per day of extra heavy crude. Development plans for the next 5 years call for production of 1 million barrels per day.

About 60 percent of this production would be Orimulsion, a bitumen based boiler fuel. The remainder would be converted to light synthetic crude oil. PDVSA can produce and distribute 50,000 barrels of Orimulsion per day. Facilities are under construction that will boost production to 100,000 barrels per day in 1992.

PDVSA has joined forces with Mobil Corporation in 1992 to explore other options for marketing heavy crude in addition to orimulsion.

In October 1991, the Kashima-Kita Electric Power Corporation of Japan began firing their generators with 700 tons per day of orimulsion. Another Japanese utility, Mitsubishi Kasei Corporation, began working with Orimulsion in February 1992.

Recently, Venezuela's Ministry of Energy and Mines ordered PDVSA to scale back its program to develop Orimulsion in order to focus current efforts on light and medium crude.

Project Cost: $2.5 billion

OSLO PROJECT — Esso Resources (25%), Canadian Occidental (20%), Gulf Canada (20%), Petro-Canada (15%), PanCanadian Petroleum (10%), Alberta Oil Sands Equity (10%). (T-150)

The OSLO joint venture was to be an 80,000 barrel per day oil sands mine and extraction plant 60 kilometers north of Fort McMurray, and an upgrader situated about 7 kilometers south of Redwater, near Edmonton. Production was scheduled to begin in 1996.

On February 20, 1990 the Canadian federal government announced the withdrawal of its previous commitment to finance $1.6 billion of the $4.5 billion project. To the end of 1989, $75 million had been spent on project studies. In mid-1990, however, the Alberta government pledged to provide $47 million to complete the engineering phase. Alberta's contribution represented 36 percent of the estimated $130 million total cost for the engineering phase. The Canadian federal government contributed about $45.5 million, 35 percent of the total, for the engineering phase. The OSLO consortium funded the rest.

Project Cost: $47 million

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

The engineering phase was completed by the end of 1991. Engineering work was focused on the Edmonton-area upgrader to be linked directly to OSLO's Fort McMurray bitumen production via pipeline. The pipeline is planned to be open to other operators to move their product. A second pipeline would return the diluent to the bitumen production facility.

If built, the project would use conventional surface mining techniques to strip the overburden and mine the oil sands. At the plant, the bitumen would be extracted from the sand by warm water and chemicals and sent to the upgrader by pipeline. There, it would be converted into synthetic crude oil with properties similar to conventional light crude oil—suitable as feedstock for Canadian refineries. OSLO has selected the high-conversion Veba Combi Cracking process for upgrading.

According to OSLO, the OSLO reserves are large enough that a project could produce 200,000 barrels of synthetic crude oil per day for almost 50 years.

In early 1992 the OSLO partners decided that they could go no further with the project without government support. When the final work on technical design and environmental assessment was completed, the OSLO offices in Calgary, Alberta were be closed. The project will not be built until economic conditions improve.

Project Cost: $4.5 billion estimated

PEACE RIVER COMPLEX -- Shell Canada Limited (T-160)

Shell Canada Limited expanded the original Peace River In Situ Pilot Project to an average production rate of 10,000 barrels per day. The Peace River Expansion Project, or PREP I, is located adjacent to the existing pilot project, approximately 55 kilometers northeast of the town of Peace River, on leases held jointly by Shell Canada Limited and Pecten Canada Limited.

The expansion, at a cost of $200 million, required the drilling of an additional 213 wells for steam injection and bitumen production, plus an expanded distribution and gathering system. Wells for the expansion were drilled directionally from eight pads. The commercial project includes an expanded main complex to include facilities for separating water, gas, and bitumen; a utility plant for generating steam; and office structures. Additional off-site facilities were added. No upgrader is planned for the expansion; all bitumen extracted is diluted and marketed as a blended heavy oil. The diluted bitumen is transported by pipeline to the northern tier refineries in the United States and the Canadian west coast for asphalt production.


In 1989 production was increased to the design capacity of 1,600 cubic meters of oil per day. This rate continued in 1990. With a modification to the steam drive process, production during 1991 is anticipated to exceed the original design at 1,800 cubic meters per day. Coincident with this increase in production is a reduced steam requirement which contributes to improved efficiency of the current operation and reduced operating costs.

On January 25, 1988 the ERCB approved Shell Canada's application to expand the Peace River project from 10,000 barrels per day to approximately 50,000 barrels per day. PREP II, as it will be called, entails the construction of a stand-alone processing plant, located about 4 km south of PREP I. PREP II would be developed in four annual construction stages, each capable of producing 1,600 cubic meters per day. However, due to low world oil prices and continual uncertainty along with the lack of improved fiscal terms the expansion project has been postponed indefinitely. Some preparatory site work was completed in 1988 consisting of the main access road and drilling pads for PREP II. The ERCB approval for PREP II was allowed to lapse, however, in December 1990. Continued world oil price uncertainty contributed largely to the decision not to seek an expansion.

Advances continue to be made in recovery technology, with a recent shift to continuous steam drive. Production in 1990 increased 20 percent over 1989, while gross operating costs were reduced by nearly 10 percent.

Research began in 1990 to assess the potential for in situ upgrading of bitumen through the use of metal ion and non-condensable gas additives. The result of adding various transition metal ions and/or carbon monoxide to Peace River oil sand, under high pressure steam conditions and over varying time periods, is being investigated. The primary objective of adding a transition metal ion is to catalyze high temperature bond breaking reactions in asphaltenic molecules, causing a reduction in both molecular size and viscosity of these heavy bitumen components.

The Peace River complex completed its first full year of operating at capacity in 1990. Its 10 millionth barrel of bitumen was produced in March. Through a combination of increased bitumen production and reduced energy requirements, the unit bitumen production cost has been reduced to 30 percent of that averaged during the first full year of operation.

Project Cost: $200 million for PREP I
$570 million for PREP II
PRIMROSE LAKE COMMERCIAL PROJECT – Amoco Canada Petroleum Company and Alberta Energy Company (T-170)

Amoco (formerly Dome) proposed a 25,000 barrels per day commercial project in the Primrose area of northeastern Alberta. Amoco is earning a working interest in certain oil sands leases from Alberta Energy Company. Following extensive exploration, the company undertook a cyclic steam pilot project in the area, which commenced production in November 1983, and thereby earned an interest in eight sections of adjoining oil sands leases. The 41 well pilot was producing 2,000 barrels per day of 10 degrees API oil in 1984.

The agreement with Alberta Energy allows Amoco to earn an interest in an additional 194,280 acres of adjoining oil sands lands through development of a commercial production project. The project is estimated to carry a capital cost of at least $1.2 billion and annual operating cost of $140 million. Total production over a 30 year period will be 190 million barrels of oil or 18.6 percent of the oil originally in place in the project area. Each section will contain four 26-well slant-hole drilling clusters. Each set of wells will produce from 160 acres on six acre spacing. The project received Alberta Energy Resources Conservation Board approval on February 4, 1986. A subsequent amendment to the original scheme was approved on August 18, 1988. The 12,800 acre project will be developed in three phases. Four 6,500 barrel per day modules will be used to meet the 25,000 barrel per day target.

In 1989, Amoco undertook some additional work at the site by drilling a horizontal well. In 1990 Amoco announced it would drill two more wells to assist in engineering design work. Six hundred thousand dollars was planned to be spent on this effort in 1990.

A new steam injection heavy oil pilot was placed in production in early 1991. By the end of 1991, AEC expected to be testing more than 80 wells using various techniques, including a cold technique which employs specialized pumps.

In 1991, ERCB gave approval for seven horizontal wells to maximize bitumen recovery under a steam stimulation/gravity drainage process. AEC expects its share of Primrose heavy oil production to grow, to about 10,000 barrels per day over the next 5 years and double by the late 1990s.

Using a newly developed "cold production" technique, four wells have been producing for more than a year at rates averaging 140 barrels per day per well. This technique significantly reduces capital and operating costs as compared to steam injection techniques. Further testing of this technology continues in 1992.

AEC estimates that cold production technology could yield 6,000 barrels per day by 1993, with a planned expansion to 12,500 barrels per day in 1995.

Project Cost: $1.2 billion (Canadian) capital cost
$140 million (Canadian) annual operating cost

SCOTFORD SYNTHETIC CRUDE REFINERY - Shell Canada Limited (T-180)

The project is the world's first refinery designed to use exclusively synthetic crude oil as feedstock, located northeast of Fort Saskatchewan in Strathcona County.

Initial capacity was 50,000 barrels per day with the design allowing for expansion to 70,000 barrels per day. Feedstock is provided by the two existing oil sands plants, Syncrude and Suncor. The refinery's petroleum products are gasoline, diesel, jet fuel and stove oil. Byproducts include butane, propane, and sulfur. Sufficient benzene is produced to feed a 300,000 tonne/year styrene plant. The refinery and petrochemical plant officially opened September 1984.

Project Cost: $1.4 billion (Canadian) total final cost for all (refinery, benzene, styrene) plants.

SUNCOR, INC., OIL SANDS GROUP – Sun Company, Inc. (72.8 percent), Ontario Energy Resources Ltd. (25 percent), publicly (2.2 percent) (T-190)

Suncor Inc. was formed in August 1979, by the amalgamation of Great Canadian Oil Sands and Sun Oil Co., Ltd. In November 1981, Ontario Energy Resources Ltd., acquired a 25 percent interest in Suncor Inc.

Suncor Inc. operates a commercial oil sands plant located in the Athabasca bituminous sands deposit 30 kilometers north of Fort McMurray, Alberta. It has been in production since 1967. A four-step method is used to produce synthetic oil. First, overburden is removed to expose the oil-bearing sand. Second, the sand is mined and transported by conveyors to the extraction unit. Third, hot water and steam are used to extract the bitumen from the sand. Fourth, the bitumen goes to upgrading where thermal cracking produces coke, and cooled vapors form distillates. The distillates are desulfurized and blended to form high-quality synthetic crude oil which is shipped to Edmonton for distribution.

Current remaining reserves of synthetic crude oil are 276 million barrels.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

A phased approach to the debottlenecking project will increase plant capacity without the large upfront cash requirements.

In 1991, Oil Sands Group set an all-time monthly record producing 22.1 million barrels of synthetic crude oil. Cash operating costs averaged $15.75 per barrel during 1991. Earnings for 1991 were $48 million.

After December 31, 1991, the royalty changed to be the greater of 5 percent of revenues or 30 percent of revenues less allowed operating and capital costs.

Sun Company, Inc. announced in early 1992 its intention along with partner Ontario Energy Corporation (OEC) to sell up to 45% interest in Suncor. Sun intends to reduce its 75% share to 55% and OEC would sell its entire 25% interest in Suncor.

A fire occurred in the upgrader section of the plant on April 3, but was quickly reduced to controlled burning of residual oil in the affected systems and then extinguished entirely on April 4. The fire was caused by a hole in a valve in a process gas line. There were no injuries and damage was contained to the hydrotreating area of the upgrader. Bitumen production continued without interruption, but the upgrading operations were affected. Total physical damages of the incident are estimated to be in the C$10 to C$20 million range. Any costs in excess of C$12 million are covered by insurance.

The plant achieved record production levels in the first quarter of 1992, averaging 64,200 barrels per day, or about 250,000 barrels above the same period last year.

In November 1991, Suncor applied to the ERCB to increase primary bitumen production as much as 2,000 cubic meters per day.

Project Cost: Not disclosed

SUNNYSIDE PROJECT – Amoco Production Company (T-200)

Amoco Corporation is studying the feasibility of a commercial project on 1,120 acres of fee property and 9,600 acres of combined hydrocarbon leases in the Sunnyside deposit in Carbon County, Utah. Research is continuing on various extraction and retorting technologies. The available core data are being used to determine the extent of the mineable resource base in the area and to provide direction for any subsequent exploration work.

A geologic field study was completed in September 1986; additional field work was completed in 1987. In response to Mono Power Company's solicitation to sell their (federal) lease interests in Sunnyside tar sands, Amoco Production acquired Mono Power's Combined Hydrocarbon Leases effective August 14, 1986. Amoco continued due diligence efforts in the field in 1988. This work includes a tar sand coring program to better define the resource in the Combined Hydrocarbon Lease.

Project Cost: Not disclosed

SUNNYSIDE TAR SANDS PROJECT – GNC Energy Corporation (T-210)

A 240 tons per day (120 barrels per day) tar sands pilot was built by GNC in 1982 in Salt Lake City, which employs ambient water flotation concentration. The pilot demonstrated that tar sands could be concentrated by selective flotation from 8 percent bitumen as mined to a 30 to 40 percent richness.

Chevron in 1983 built and operated a solvent leach unit that, when added in back of a flotation unit at Colorado School of Mines Research Institute (CSMRI) in Denver, produced a bitumen dissolved in a kerosene solvent with a ratio of 1:3 which contained 5 percent ash and water. Chevron also ran a series of tests using the solvent circuit first followed by flotation and found it to be simpler and cheaper than the reverse cycle.

Kellogg, in a series of tests during 1983/1984, took the product from the CSMRI tests and ran it through their Engelhard ARTCAT pilot plant in Houston, Texas and produced a 27 degrees API crude out of the 10 percent API bitumen, recycled the solvent, and eliminated the ash, water, and 80 percent of the metals, nitrogen, and sulfur.

Today GNC has a complete process that on tests demonstrates 96 to 98 percent recovery of mined bitumen through the solvent and flotation units and converts 92 percent of that stream to a 27 degrees API crude with characteristics between Saudi Light and Saudi Heavy.

GNC has 2,000 acres of fee leases in the Sunnyside deposit that contain an estimated 307 million barrels of bitumen. It has applied to BLM for conversion of a Sunnyside oil and gas lease to a combined hydrocarbon lease. The first commercial facility will be 7,500 barrels per day. In response to a solicitation by the United States Synthetic Fuels Corporation (SFC) for tar sands projects that utilize mining and surface processing methods, GNC requested loan and price guarantees of $452,413,000. On November 19, 1985 the SFC determined that the project was a qualified candidate for assistance under the terms of the solicitation.

SYNTHETIC FUELS REPORT, JUNE 1992

3-37
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

On December 19, 1985, the SFC was canceled by Congressional action before giving any financial assistance to the project. GNC is now attempting to finance independently of United States government assistance. Studies have been completed by M. W. Kellogg and Engelhard indicating feasibility, after the decline in prices beginning in January 1986, of a 7,500 barrels per day plant which converts the ART-treated bitumen to 31 percent gasoline and 69 percent diesel. The 7,500 barrels per day plant including upgrading to products, with some used equipment, would cost $149 million.

As of 1992, GNC is still looking for financial partners, however, little progress has been made since the 1980's.

Project Cost: $149 million for 7,500 barrels per day facility

SYNCO SUNNYSIDE PROJECT - Synco Energy Corporation (T-220)

Synco Energy Corporation of Orem, Utah is seeking to raise capital to construct a plant at Sunnyside in Utah's Carbon County to produce oil and electricity from coal and tar sands.

The Synco process to extract oil from tar sands uses coal gasification to make a synthetic gas. The gas is cooled to 2,000 degrees F by making steam and then mixed with the tar sands in a variable speed rotary kiln. The hot synthetic gas vaporizes the oil out of the tar sands and this is then fractionated into a mixture of kerosene (jet fuel), diesel fuel, gasoline, other gases, and heavy ends.

The syngas from the gasifier is separated from the oil product, the sulfur and CO2 removed and the gas is burned in a gas turbine to produce electricity. The hot exhaust gases are then used to make steam and cogenerated electricity. Testing indicates that the hydrogen-rich syngas from the gasified coal lends to good cracking and hydrogen upgrading in the kiln.

The plant would be built at Sunnyside, Utah, near the city of Price.

There is a reserve of four billion barrels of oil in the tar sands and 230 million tons of coal at the Sunnyside site. Both raw materials could be conveyed to the plant by conveyor belt.

The demonstration size plant would produce 8,000 barrels of refined oil, 330 megawatts of electricity, and various other products including marketable amounts of sulfur.

An application has been filed by Synco with the Utah Division of State Lands for an industrial special use lease containing the entire Section 36 of State land bordering the town of Sunnyside, Utah. Synco holds process patents in the U.S., Canada and Venezuela and is looking for a company to join venture with on this project.

Project Cost: $350 million

SYNCRUDE CANADA, LTD. - Esso Resources Canada (25.0%); Petro-Canada Inc. (12.0%); Alberta Oil Sands Equity (16.74%); Alberta Energy Company (10.0%); PanCanadian Petroleum Limited (10.0%); Gulf Canada Resources Ltd. (9.03%); Canadian Occidental Petroleum Ltd. (7.23%); HBOG - Oil Sands Ltd. Partnership (Amoco Canada Petroleum Company Ltd.) (5.0%); Mitsubishi Oil Company (5.0%) (T-230)

Located near Fort McMurray, the Synrude surface mining and extraction plant produces 155,000 barrels per calendar day. The original plant with a capacity of 108,000 barrels was based upon: oil sand mining and ore delivery with four dragline-bucketwheel reclaimers-conveyor systems; oil extraction with hot water flotation of the ore followed by dilution centrifuging; and upgrading by fluid coking followed by hydrotreating. During 1988, a 6-year $1.5 billion investment program in plant capacity was completed to bring the production capability to over 155,000 barrels per calendar day. Included in this investment program are a 40,000 barrel per day L-C Fining hydrotreater, additional hydrotreating and sulfur recovery capacity, and auxiliary mine feed systems as well as debottlenecking of the original processes.

In 1990 production averaged over 180,000 barrels per day with operating costs of about C$16 per barrel. Operating costs are projected to reach $15 per barrel over the next 2 years. Production is expected to reach the level of 66 million barrels per year over the next few years through continued operating improvements and efficiencies. Synrude Canada Ltd. produced 11 percent of Canada's crude oil requirements in 1990. Production during the first months of 1991 averaged 152,000 barrels per day.

In an effort to streamline production costs and appear more attractive to prospective buyers, Synrude will cut the plant's 4,600 workers by 400 by 1996.

Twice-generated NiMo catalyst has been used successfully in the commercial hydrotreater processing bitumen-derived hydrotreater and virgin light gas oils. The run length was 25 months or 81 barrels of feed per pound of catalyst. The unit run was terminated because of high reactor pressure drop due to treating fines- and sodium-contaminated coker gas oil, not because of catalyst exhaustion. Decrease in catalyst activity during this period corresponded to a 13 C increase in reactor temperature. The hydrotreating reduction was about 85 to 95 percent for sulfur and 60 to 75 percent for nitrogen.

SYNTHETIC FUELS REPORT, JUNE 1992

3-38
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

In 1991, higher production and the cost reduction program resulted in the unit cost of production being reduced by $1.05 per barrel to $16.48 per barrel. Syncrude produced synthetic oil in an amount equal to 18 percent of Canada's light and medium-gravity oil production.

Project Cost: Total cost $3.8 billion

THREE STAR OIL MINING PROJECT - Three Star Drilling and Producing Corp. (T-240)

Three Star Drilling and Producing Corporation has sunk a 426 foot deep vertical shaft into the Upper Siggins sandstone of the Siggins oil field in Illinois and drilled over 34,000 feet of horizontal boreholes up to 2,000 feet long through the reservoir. The original drilling pattern was planned to allow the borehole to wander up and down through the producing interval in a "snake" pattern. However, only straight upward slanting holes are being drilled. Three Star estimates the Upper Siggins still contains some 35 million barrels of oil across the field.

The initial plans call for drilling one to four levels of horizontal boreholes. The Upper Siggins presently has 34 horizontal wells which compose the 34,000 feet of drilling.

Sixty percent of the horizontal drilling was completed by late 1990. Production was put on hold pending an administrative hearing to determine whether the mine is to be classified as gaseous or non-gaseous. The project was later classified as a gaseous mine due to the fact that the shaft penetrated the oil reservoir. As a result of the ruling, Three Star then drilled a vertical well to the underground sump room and began producing the mine conventionally with all the horizontals open. In 1992, Three Star will begin reworking the surface wells for injection purposes in order to pressure up the Upper Siggins.

Project Cost: Three Star budgeted $35 million for the first shaft.

WOLF LAKE PROJECT - Amoco Canada Petroleum (T-260)

Located 30 miles north of Bonnyville near the Saskatchewan border, on 75,000 acres, the Wolf Lake commercial oil sands project (a joint venture between BP Canada Resources Ltd. and Petro-Canada) was completed and began production in April 1985. Production at designed capacity of 7,000 barrels per day was reached during the third quarter 1985. The oil is extracted by the huff-and-puff method. Nearly two hundred wells were drilled initially, then steam injected. As production from the original wells declines more wells will be drilled.

An estimated 720 wells will be needed over the expected 25-year life of the project. Because the site consists mostly of muskeg, the wells will be directionally drilled in clusters of 20 from special pads. The bitumen is heavy and viscous (10 degrees API) and thus cannot be handled by most Canadian refineries. There are no plans to upgrade the bitumen into a synthetic crude; much of it will probably be used for the manufacture of asphalt or exported to the northern United States.

By mid-1988 production had dropped 22 percent below 1987 levels. Following a change of strategy in operation of the reservoir, however, production had increased to 1,030 cubic meters per day in 1989 and 1,147 cubic meters per day in 1990. Continuing the trend, 1991 will see an average production rate of 1,167 cubic meters per day.

In 1987, a program designed to expand production by 2,400 cubic meters per day to 3,700 cubic meters per day, total bitumen production was initiated. Wolf Lake 2 was originally expected to be completed in mid-1989.

In early 1989, BP Canada and Petro-Canada delayed by 1 year the decision to start up the second phase. While the Wolf Lake 2 plant was commissioned in 1990, full capacity utilization of the combined project is not likely before the late 1990s when it is expected that higher bitumen prices will support the expanded operation and further development.

The new water recycle facilities and the Wolf Lake 2 generators are operational. Production levels will be maintained at 600 to 700 cubic meters per day until bitumen netbacks have improved. The Wolf Lake 2 oil processing plant and Wolf Lake 1 steam generating facilities have been suspended.

In September 1989, Wolf Lake production costs were reported to be almost C$22 per barrel, while bitumen prices fell to a low of C$8.19 per barrel in 1988. BP initiated a program to reduce Wolf Lake costs, which included laying off 120 workers, making improvements in process efficiency, and operating the plant at about 50 percent of capacity. These economic measures cut operating costs to C$10 to 12 per barrel.

In 1991, Wolf Lake production costs were less than $9 per barrel, and bitumen production averaged 4,225 barrels a day.

In early 1992, BP Canada and Petro-Canada sold their entire interests in the project to Amoco Canada Petroleum. No price was disclosed but both companies have written off their total $370 million investment in the project.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

Project Cost:  

Wolf Lake I  
$114 million (Canadian) initial capital  
(Additional $750 million over 25 years for additional drilling)

Wolf Lake II  
$200 million (Canadian) initial capital

YAREGA MINE-ASSISTED PROJECT -- Union of Soviet Socialist Republics (T-265)

The Yarega oilfield (Soviet Union) is the site of a large mining-assisted heavy oil recovery project. The productive formation of this field has 26 meters of quartz sandstone occurring at a depth of 200 meters. Average permeability is 3.17 mKm⁻¹. Temperature ranges from 279 to 281 degrees K; porosity is 26 degrees; oil saturation is 87 percent of the pore volume or 10 percent by weight. Viscosity of oil varies from 15,000 to 20,000 mPa per second; density is 945 kilograms per cubic meter.

The field has been developed in three major stages. In a pilot development, 69 wells were drilled from the surface at 70 to 100 meters spacing. The oil recovery factor over 11 years did not exceed 1.5 percent.

Drainage through wells at very close spacing of 12 to 20 meters was tested with over 92,000 shallow wells. Development of the oilfield was said to be profitable, but the oil recovery factor for the 18 to 20 year period was approximately 3 percent.

A mining-assisted technique with steam injection was developed starting in 1968. In 18 years, 10 million tons of steam have been injected into the reservoir.

Three mines have been operated since 1975. An area of the deposit covering 225 hectares is under thermal stimulation. It includes 15 underground slant blocks, where 4,192 production wells and 11,795 steam-injection wells are operated. In two underground slant production blocks, which have been operated for about 8 years, oil recovery of 50 percent has been reached. Construction of 4 new shafts is expected to bring production to over 30,000 barrels per day. Forty-one million barrels of oil were produced during the period 1975-1987. A local refinery produces lubricating oils from this crude.

Project Cost:  
Not Disclosed

R & D PROJECTS

ATHABASCA IN SITU PILOT PROJECT (Kearl Lake) -- Alberta Oil Sands Technology and Research Authority, Husky Oil Operations Ltd., Esso Resources Canada Ltd. (T-270)

The pilot project began operation in December, 1981. The pilot was developed with the following objectives in mind: Evaluate the use of horizontal hydraulic fractures to develop injector to producer communication; optimize steam injection rates; maximize bitumen recovery; assess the areal and vertical distribution of heat in the reservoir; evaluate the performance of wellbore and surface equipment; and determine key performance parameters.

The operator of the Athabasca In Situ Pilot Project is Husky Oil Operations Ltd. In 1990 three patterns were being operated: one 9-spot and two 5-spots. The central well of each pattern is an injector. Eight observations wells are located in and around the three patterns. The 9-spot pattern was started up in 1985. The two 5-spot patterns were started up in 1987. Results from all three patterns continue to be encouraging, according to Husky.

In 1990 the project passed the one million barrel production mark and at the end of January 1991 the project entered its final, winddown phase. The winddown phase consists of reducing the central steam injection to zero and continuing to produce until the end of April 1991. The project was shut down at the end of April 1991, after a majority of the technical objectives had been met.

In July 1991, all production, injection and observation wells were abandoned and the central facilities mothballed.

Project Cost:  
Capital $54 million, operating $73 million

BATTRUM IN SITU WET COMBUSTION -- Mobil Oil Canada, Unocal Canada Limited, Saskoil, Hudson's Bay Oil and Gas (T-280)

Mobil Oil Canada initiated dry combustion in the Battrum field, near Swift Current, Saskatchewan, in 1965 and converted to wet combustion in 1978. The combustion scheme, which Mobil operates in three Battrum units, was expanded during 1987-88. The expansion included drilling 46 wells, adding 12 new burns, a workover program and upgrading surface production and air injection facilities. There are presently 18 burns in operation.

All burns have been converted to wet combustion and the air injection rate is 25 million cubic feet per day. Studies have been initiated to determine the feasibility of oxygen enrichment for the EOR scheme.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

BUENAVENTURA COLD PROCESS PILOT – Buenaventura Resource Corp. (T-287)

Buenaventura Resource Corporation owns the exclusive license to use a patented process to extract oil from tar sands in the United States and Canada. The cold process was invented by Park Guymon of Weber State University.

The two step process uses no heat in extracting heavy oil from tar sands. Asphalt can be made from the oil, or it can be refined for use as a motor oil. The company is currently assessing the market for these products.

The process will be developed in three phases. The first phase is a small pilot plant to be installed at or near Weber State University. The plant is being built in Texas and was shipped to Utah in the fall of 1990 for installation. The project's second phase will be a larger pilot plant and the third phase will be a commercial-scale plant.

Buenaventura has been working on developing the new process in Uintah County, Utah since 1986. Funding for the project is being sought from the State of Utah and the United States Department of Energy.

CARIBOU LAKE PILOT PROJECT – Husky Oil Operations Ltd. (60%) and Alberta Energy Co. (40%) (F-310)

Husky Oil Operations Ltd. and Alberta Energy Co. received ERCB approval for a 1,100 barrels per day heavy oil steam pilot in the Primrose block of the Cold Lake Air Weapons Test Range in northeastern Alberta.

In September, 1989, Husky and AEC Oil & Gas Company announced their intention to proceed with the development of the Caribou Lake Pilot Project. This project will test the potential commercial application of producing heavy oil using cyclic steaming technology. Husky will operate the project.

Construction at the Caribou Lake Pilot Project was completed in early 1991 and the operations phase of the project has begun. The Pilot consists of 25 cyclic steam/production wells, 75 MMBTU/hour steam generation capacity and associated oil treating and produced water clarification facilities. A comprehensive testing and analysis program to define technology for maximum reuse of produced water will be incorporated. The pilot will likely span 3 to 7 years depending on the results. The total average output of the project is expected to be 1,200 barrels of heavy oil per day.

Project Cost: Approximately $20 Million

CELTIC HEAVY OIL PILOT PROJECT – Mobil Oil Canada (T-320)

Mobil's heavy oil project is located in T52 and R23, W3M in the Celtic Field, northeast of Lloydminster. The pilot consists of 25 wells drilled on five-acre spacing, with twenty producers and five injectors. There is one fully developed central inverted nine-spot surrounded by four partially developed nine-spots. The pilot was to field test a wet combustion recovery scheme with steam stimulation of the production wells.

Air injection, which was commenced in October 1980, was discontinued in January 1982 due to operational problems. An intermittent steam process was initiated in August 1982. The seventh steam injection cycle commenced in January, 1987. Operations were suspended in 1988-89.

Production in the Celtic Multizone Test, an expansion of the Heavy Oil Pilot, consisting of 16 wells on 20 acre spacing, commenced with primary production in September, 1988. First cycle steam injection commenced May, 1989. This test operation is now part of the total Celtic field operation.

Project Cost: $21 million (Canadian) (Capital)

C-H SYNFUELS DREDGING PROJECT – C-H Synfuels Ltd. (T-330)

C-H Synfuels Ltd. plans to construct an oil sands dredging project in Section 8, Township 89, Range 9, west of the 4th meridian.

The scheme would involve dredging of a cutoff meander in the Horse River some 900 meters from the Fort McMurray subdivision of Abasand Heights. Extraction of the dredged bitumen would take place on a floating modular process barge employing a modified version of the Clark Hot Water Process. The resulting bitumen would be stored in tanks, allowed to cool and solidify, then transported, via truck and barge, to either Suncor or the City of Fort McMurray. Tailings treatment would employ a novel method combining the sand and sludge, thus eliminating the need for a large conventional tailings pond.

C-H proposes to add lime and a non-toxic polyacrylamide polymer to the tailings stream. This would cause the fines to attach to the sand eliminating the need for a sludge pond.

Project Cost: Not disclosed
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

CIRCLE CLIFFS PROJECT — Kirkwood Oil and Gas (T-340)

Kirkwood Oil and Gas is forming a combined hydrocarbon unit to include all acreage within the Circle Cliffs Special Tar Sand Area, excluding lands within Capitol Reef National Park and Glen Canyon National Recreational Area.

Work on this project was suspended in 1990 until an Environmental Impact Statement can be completed.

Project Cost: Not disclosed

COLD LAKE STEAM STIMULATION PROGRAM - Mobil Oil Canada (T-350)

A stratigraphic test program conducted on Mobil's 75,000 hectares of heavy oil leases in the Cold Lake area resulted in approximately 150 holes drilled to date. Heavy oil zones with a total net thickness of 30 meters have been delineated at depths between 290 and 460 meters. This pay is found in sand zones ranging in thickness from 2 to 20 meters.

Single well steam stimulations began in 1982 to evaluate the production potential of these zones. Steam stimulation testing was subsequently expanded from three single wells to a total of fourteen single wells in 1988. Various zones have been tested in the Upper and Lower Grand Rapids formation. The test well locations are distributed throughout Mobil's leases in Townships 63 and 64 and Ranges 6 and 7 W4M. Based on encouraging results, the Iron River Pilot [see Iron River Pilot Project (T-440)] was constructed with operations beginning in March, 1988. To date, steam stimulation tests have been conducted in a total of 14 vertical wells.

Five vertical wells, all multizone completions, were still in operation in 1991; the remaining wells were suspended at the conclusion of their testing programs. No further steaming of the single wells is planned. A single zone, conduction assisted steam stimulation in a horizontal well began in mid-1989. This test was still operating in 1990.

Project Cost: Not disclosed

DONOR REFINED BITUMEN PROCESS — Gulf Canada Resources Limited, the Alberta Oil Sands Technology and Research Authority, and L'Association pour la Valorisation des Huiles Lourdes (ASVAHL) (T-360)

An international joint venture agreement has been signed to test the commercial viability of the Donor Refined Bitumen (DRB) process for upgrading heavy oil or bitumen.

About 12,000 barrels of Athabasca bitumen from the Syncrude plant were shipped to the ASVAHL facilities near Lyon, France. Beginning in October 1986 tests were conducted in a 450 barrel per day pilot plant. Engineering and economic evaluations were completed by the end of 1987.

ASVAHL is a joint venture of three French companies—Elf Aquitaine, Total-Compagnie Francaise de Raffinage, and Institut Francais du Petrole. The ASVAHL test facility was established to study new techniques, processes and processing schemes for upgrading heavy residues and heavy oils at a demonstration scale.

The DRB process entails thermally cracking a blend of vacuum residual and a refinery-derived hydrogen-rich liquid stream at low pressure in the liquid phase. The resulting middle distillate fraction is rehydrogenated with conventional fixed bed technology and off-the-shelf catalysts.

Project Cost: Not disclosed

ESSO COLD LAKE PILOT PROJECTS — Esso Resources Canada Ltd. (T-380)

Esso operates two steam based in situ recovery projects, the May-Ethel and Laming pilot plants, using steam stimulation in the Cold Lake Deposit of Alberta. Tests have been conducted since 1964 at the May-Ethel pilot site in 27-64-3W4 on Esso's Lease No. 40. Esso has sold these data to several companies. Esso's Laming pilot is located in Sections 4 through 8-65-3W4. The Laming pilot uses several different patterns and processes to test future recovery potential. Esso expanded its Laming field and plant facilities in 1980 to increase the capacity to 14,000 barrels per day at a cost $60 million. A further expansion, costing $40 million, debottlenecked the existing facilities and increased the capacity to 16,000 barrels per day. By 1986, the pilots had 500 operating wells. Approved capacity for all pilot projects is 3,100 cubic meters per day—i.e., about 19,500 barrels per day of bitumen.

Major prototype facilities for the commercial-scale Cold Lake Project will continue to be tested including three 175,000 pounds per hour steam generators, and a water treatment plant to convert the saline water produced with the bitumen into a suitable feedwater for the steam generators. Additionally, the pilots serve as a testing area for optimizing the parameters of cyclic steam stimulation as well as on follow-up recovery methods, such as steam displacement and horizontal wells.

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

(Also see Cold Lake in commercial projects listing)

Project Cost: $260 million

EYEHILL IN SITU COMBUSTION PROJECT—Canadian Occidental Petroleum, Ltd., C.S. Resources Ltd. and Murphy Oil Company Ltd. (T-390)

The experimental pilot is located in the Eyehill field, Cummings Pool, at Section 16-40-28-W3 in Saskatchewan six miles north of Macklin. The pilot consists of nine five spot patterns with 9 air injection wells, 24 producers, 3 temperature observation wells, and one pressure observation well. Infill of one of the patterns to a nine-spot was completed September 1, 1984. Five of the original primary wells that are located within the project area were placed on production during 1984. The pilot covers 180 acres. Ignition of the nine injection wells was completed in February 1982. The pilot is fully on stream. Partial funding for this project was provided by the Canada-Saskatchewan Heavy Oil Agreement Fund. The pilot was given the New Oil Reference Price as of April 1, 1982.

The pilot has 40 feet of pay with most of the project area pay underlain by water. Reservoir depth is 2,450 feet. Oil gravity is 14.3 degrees API, viscosity 2,750 Cp at 70 degrees F, porosity 34 percent, and permeability 6,000 md.

Cumulative production reached one million barrels in 1988. This represents about 6 percent of the oil originally in place in the project area. Another four million barrels is expected to be recovered in the project's remaining 10 years of life after 1988.

Production in 1990 continued at 500 barrels per day. The air compressors supplying combustion air were shut-in in June 1990. Secondary processes for additional recovery will be reviewed during 1992.

Project Cost: $15.2 million

FORT KENT THERMAL PROJECT—Koch Industries and Canadian Worldwide Energy Corporation (T-400)

Canadian Worldwide Energy Ltd. and Suncor, Inc., developed heavy oil deposits on a 4,960 acre lease in the Fort Kent area of Alberta. Canadian Worldwide holds a 50 percent working interest in this project, with Koch Industries now replacing Suncor. This oil has an average gravity of 123 degrees API, and a sulfur content of 33 percent. The project utilizes huff and puff, with steamdrive as an additional recovery mechanism. The first steamdrive pattern was commenced in 1980, with additional patterns converted from 1984 through 1988. Eventually most of the project will be converted to steamdrive.

A total of 126 productive wells are included in this project, including an 8 well cluster drilled in late 1985. Five additional development well locations have been drilled. Approximately 59 wells are now operating, with production averaging 1,600 barrels per day. Further development work, including tying-in the 8 wells most recently drilled, has been delayed. Ultimate recoveries are anticipated to be greater than 21 percent with recoveries in the 26 percent range in the steamflood areas expected.

Because of the experimental work being carried out, this project qualifies for a reduced royalty rate of only 5 percent. Canadian Worldwide's share of the project costs to 1988 is approximately $35 million (Canadian).

In January 1989, it was announced that the project would be indefinitely suspended.

Project Cost: See Above

FROG LAKE PILOT PROJECT—Texaco Canada Petroleum (T-405)

The Frog Lake Lease is located about 50 miles northwest of Lloydminster, Alberta in the southeastern portion of the Cold Lake Oil Sands deposit. The lease contains a number of heavy oil producing horizons, but primary production rates are generally restricted to less than 5 cubic meters per day per well due in large part to the high viscosity of the oil.

During the 1960's steam stimulation treatments were carried out on several wells on the Frog Lake lease but based on these tests it was concluded that conventional thermal recovery methods using steam are hampered by the thermal inefficiency associated with the thin sands.

In 1991 Texaco began preparing to apply electromagnetic heating to stimulate three Lower Wasca wells at Frog Lake. The wells were placed on production in late November 1990 and electromagnetic heating was scheduled to commence by mid-1991.

Upon completion of the tests in 1993 it is expected there will be sufficient data available to develop reliable economics for a commercial project. A reservoir simulator will be used to history-match test results and make predictions of production rates and ultimate recovery for various well patterns and spacing.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

GLISP PROJECT – Amoco Canada Petroleum Company Ltd. (14.29%) and AOSTRA (85.71%) (T-420)

The Gregoire Lake In-Situ Steam Pilot (GLISP) was an experimental steam pilot located at Section Z-86-7W. Phase B operations were terminated in July 1991 due to financial limitations. Petro-Canada had participated in Phase A of the project, but declined to participate in Phase B which was initiated in 1990. The lease is shared jointly by Amoco and Petro-Canada. Amoco is the operator.

The GLISP production pattern consisted of a four spot geometry with an enclosed area of 0.28 hectares (0.68 acres). The process tested the use of steam and steam additives in the recovery of high viscous bitumen (1x10 million eP at virgin reservoir temperature). Special fracturing techniques were tested. Three temperature observation wells and seismic methods were used to monitor the in-situ process.

The project began operation in September 1985. Steaming operations were initiated in October 1986 to heat the production wellbores. A production cycle was initiated in January 1987 and steam foam flooding began in October 1988. Foam injection was terminated in February 1991. Steam diversion using low temperature oxidation was tested between April and July 1991. Operations at GLISP were suspended July 18, 1991.

Project Cost: $26 million (Canadian)

HANGINGSTONE PROJECT – Petro-Canada, Canadian Occidental Petroleum Ltd., Esso Resources Canada Limited and Japan Canadian Oil Sands (T-430)

Construction of a 13 well cyclic steam pilot with 4 observation wells was completed and operation began on July 1, 1990. On September 4, 1990, Petro-Canada announced their official opening of the Hangingstone Steam Pilot Plant.

The production performance of the first cycle was said to be below expectations because of cold bitumen influx into the wellbore causing severe rodfall problems and pump seizure, and a lack of heat in the zone of high bitumen saturation.

The pilot wells are now in their third production cycle.

The Group owns 34 leases in the Athabasca oil sands, covering 500,000 hectares. Most of the bitumen is found between 200 and 500 meters below the surface, with total oil in place estimated at 24 billion cubic meters.

The Hangingstone operations are expected to continue until the end of 1992. According to Petro-Canada, total expenditures will reach $160 million by 1993. Expansion to an enlarged pilot operation or a semi-commercial demonstration project could result if the current project is deemed successful.

IRON RIVER PILOT PROJECT - Mobil Oil Canada (T-440)

The Iron River Pilot Project commenced steam stimulation operations in March 1988. It consists of a 4 hectare pad development with 23 slant and directional wells and 3 observation wells on 3.2 and 1.6 hectare spacing within a 65 hectare drainage area. The project is 100 percent owned by Mobil Oil. It is located in the northwest quarter of Section 6-64-6W4 adjacent to the Iron River battery facility located on the southwest corner of the quarter section. The project is expected to produce up to 200 cubic meters of oil per day. The battery was expanded to handle the expected oil and water volumes. The produced oil is transported by underground pipeline to the battery. Pad facilities consist of 108 million kJ/hr steam generation facility, test separation equipment, piping for steam and produced fluids, and a flare system for casing gas.

To obtain water for the steam operation, ground water source wells were drilled on the pad site. Prior to use, the water is treated. Produced water is injected into a deep water disposal well. Fuel for steam generation is supplied from Mobil's fuel gas supply system and the treated oil is trucked to the nearby Husky facility at Tucker Lake.

The pilot project has been operating since 1988 and is expected to continue operation until 1992.

Project Cost: $14 million

KEARL LAKE PROJECT – See Athabasca In Situ Pilot Project (T-270)

LINDBERGH STEAM PROJECT – Murphy Oil Company, Ltd. (T-470)

This experimental in situ recovery project is located at 13-S8-5 W4, Lindbergh, Alberta, Canada. The pilot produces from a 60 foot thick Lower Grand Rapids formation at a depth of 1650 feet. The pilot began with one inverted seven spot pattern enclosing 20 acres. Each well has been steam stimulated and produced roughly eleven times. A steam drive from the center well was tested
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

from 1980 to 1983 but has been terminated. Huff-and-puff continued. Production rates from the seven-spot area were encourag-
ing, and a 9 well expansion was completed August 1, 1984, adding two more seven spots to the pilot. Oil gravity is 11 degrees API
and has a viscosity of 85,000 Cp at reservoir temperature F. Porosity is 33 percent and permeability is 2500 md.

This pilot is currently suspended due to low oil prices.
(Refer to the Lindbergh Commercial Thermal Recovery Project (T-33) listed in commercial projects.)

Project Cost: $7 million capital, $2.5 million per year operating

LINDBERGH THERMAL PROJECT—Amoco Canada Petroleum Company Ltd. (T-480)

Amoco (formerly Dome) drilled 56 wells in section 18-55-5 W4M in the Lindbergh field in order to evaluate an enriched air and air
injection fire flood scheme. The project consists of nine 30 acre, inverted seven spot patterns to evaluate the combination thermal
drive process. The enriched air scheme included three 10 acre patterns. Currently only one 10 acre enriched air pattern is operational.

Air was injected into one 10 acre pattern to facilitate sufficient burn volume around the wellbore prior to switching over to en-
riched air injection in July 1982. Oxygen breakthrough to the producing wells resulted in the shut down of oxygen injection. A concerted
plan of steam stimulating the producers and injecting straight air into this pattern was undertaken during the next several
years. Enriched air injection was reintegrated in this pattern in August 1985. Initial injection rate was 200,000 cubic feet per day of
100 percent pure oxygen. Early oxygen breakthrough was controlled in the first year of Combination Thermal Drive (CTD) by
reducing enrichment to 80% oxygen.

In the second year of CTD, further oxygen breakthrough was controlled by stopping injection, then injecting air followed by
50 percent O2. Lack of production response and corrosion caused the pilot to be shut in in mid-1990.

Project Cost: $22 million

MINE-ASSISTED PILOT PROJECT—(see Underground Test Facility Project)

MORGAN COMBINATION THERMAL DRIVE PROJECT—Amoco Canada Petroleum Company Ltd. (T-490)

Amoco (formerly Dome) completed a 46 well drilling program (7 injection wells, 39 production wells) in Section 35-51-4-W4M in
the Morgan field in order to evaluate a combination thermal drive process. The project consists of nine 30-acre seven spot pat-
terns. All wells have been steam stimulated. The producers in these patterns have received multiple steam and air/steam stimula-
tions to provide for production enhancements and oil depletion prior to the initiation of burning with air as the injection medium.
All of the nine patterns have been ignited and are being pressure cycled using air injection.

A change of strategy with more frequent pressure cycles and lower injection pressure targets was successful for pressure cycle four.
This strategy will be continued with pressure cycle five scheduled for this year. A conversion to combination thermal drive is still
planned after pressure cycling becomes unfeasible due to longer repressuring time requirements.
The project started up in 1981 and is scheduled for completion in 1995.

Project Cost: $20 million

ORINOCO BELT STEAM SOAK PILOT—Maraven (T-500)

The Orinoco Belt of 54,000 km² was divided into four areas in 1979 to effect an accelerated exploration program by the operating
affiliates (Corpoven, Lagoven, Maraven and Meneven) of the holding company Petroles de Venezuela (PDVSA).

Maraven has implemented a pilot project in the Zuata area of the Orinoco Belt to evaluate performance of slant wells, productivity
of the area, and well response to "Huff and Puff" steam injection in relation to a commercial development.

Twelve inclined wells (7 producers and 5 observers) have been drilled in a cluster configuration, using a slant rig with a well spacing
at surface of 15 meters and 300 meters in the reservoir.

The 7 production wells, completed with openhole gravel packs, have been tested prior to steam injection at rates between 30 BPD
and 200 BPD using conventional pumping equipment. Five wells have been injected, each with 10,000 tons of steam distributed
selectively over two zones. After an initial flowing period, stabilized production on the pump averaged 1,400 BPD per well with a
water cut of less than 3%.

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

With the information derived from the exploration phase, it was possible to establish an oil-in-place for the Zuata area of 487 billion STB.

PELICAN LAKE PROJECT – CS Resources Limited and Devran Petroleum Ltd. (T-510)

CS Resources acquired from Gulf Canada, the original operator, the Pelican Lake Project comprised of some 89 sections of oil sand leases.

The Pelican Lake program is designed to initially test the applicability of horizontal production systems under primary production methods, with a view to ultimately introducing thermal recovery methods.

Eight horizontal wells have been successfully drilled at the project site in north central Alberta. The Group utilizes an innovative horizontal drilling technique which allows for the penetration of about 1,500 feet of oil sands in each well. With this technique, a much higher production rate is expected to be achieved without the use of expensive secondary recovery processes.

Drilling was commenced on the first horizontal well on January 30, 1988 and drilling of the eighth well was completed in June 1988. Drilling of five more horizontal wells with horizontal sections of 3,635 feet (a horizontal record) was accomplished in December 1989 and January 1990. Four more horizontal wells were drilled in 1991 for a total of 17 horizontal wells.

All four 1991 wells contacted almost 100 percent of good quality reservoir throughout the horizontal section. The horizontal section of one well was 1,321 meters from intermediate casing point to total depth. A 496 meter lateral arm was completed off the horizontal section of a 1,137 meter main hole section. One "J" well was a limited success with a horizontal section of 907 meters.

The average drill, case and completion cost of the 1991 wells was $540,000. The wells took an average of 7.5 days to drill with the average horizontal section being 1,290 meters. The cost per horizontal meter has dropped from $1,240 per meter in 1988 to $420 per meter in 1991.

Special effort was made to keep the drilling program simple and cost-effective. A surface casing was set vertically at 110 meters, then the wells were kicked off and inclination was built gradually to 90 degrees at a rate of two degrees/10 meters. An intermediate casing was run and cemented before horizontal drilling commenced in the sand reservoir. Early production rates averaged 15 to 20 cubic meters per day, three to six times average vertical well figures. Four wells, drilled in 1988, rapidly produced with a disappointing, and unexpected high water cut, whereas no bottom water is known to exist in this particular area. However, the two subsequent horizontal wells have not had any free water problems.

Sand production has not been a major problem and the production sand content is lower than in surrounding vertical wells.

Project Cost: Not disclosed

PELICAN-WABASCA PROJECT – CS Resources (T-520)

Construction of fireflood and steamflood facilities is complete in the Pelican area of the Wabasca region. Phase I of the project commenced operations in August 1981, and Phase II (fireflood) commenced operations during September 1982. The pilot consists of a 31-well centrally enclosed 7-spot pattern plus nine additional wells. Oxygen injection into two of the 7-spot patterns was initiated in November 1984. Six more wells were added in March 1985 that completed an additional two 7-spot patterns. In April 1986, the fireflood operation was shut down and the project converted to steam stimulation. Sixteen pilot wells were cyclic steamed. One pattern was converted to a steam drive, another pattern converted to a water drive. The remaining wells stayed on production. In January/February 1986, 18 new wells were drilled and put on primary production. Cyclic steaming was undertaken in February 1987. The waterflood on the pilot ceased operation in April, 1987. Cyclic steaming of the producing wells on the 7-spot steamflood project south of the pilot was converted to steamflood in fall 1987.

In May 1989 all thermal operations had been terminated. The wells were abandoned with the exception of 13 wells that remain producing on primary production.

The use of horizontal wells is being tested. In 1991, an additional eight horizontal wells were drilled to about 1,000 meters in length.

Project Cost: Not Specified
It & D PROJECTS (Continued)

PROVOST UPPER MANNVILLE HEAVY OIL STEAM PILOT—AOSTRA, Canadian Occidental Petroleum, Ltd., Esso, Resources Canada Ltd., Murphy Oil, Noreen Energy Resources Limited (T-530)

Noreen Energy Resources Limited has applied to the Alberta Energy Resources Conservation Board to conduct an experimental cyclic steam/steam drive thermal pilot in the Provost Upper Mannville B Pool. The pilot project will consist of a single 20 acre inverted 9 spot pattern to be located approximately 20 kilometers southeast of Provost, Alberta.

An in situ combustion pilot comprising one 20 acre 5 spot was initiated in 1975. The pilot was expanded in 1982 to encompass seven 6 hectare 7 spot patterns.

All nine wells in the new steam pilot pattern will initially be subject to cyclic steam with conversion to a steam drive utilizing one central injector and eight surrounding producers as soon as communication is established between each well. All nine pattern wells were placed on primary production in February 1985.

The project was designed to be operated in four stages. The first stage was to place the wells on primary production, next to begin multicycle steam stimulation, followed by a steam drive and finally a heat scavenging waterflood. The project was estimated to last approximately 10 years. The time frame for these four phases being:

- Mar/85 - Fed/86: Primary Production
- Apr/86 - Jun/89: Cyclic Steam Stimulation
- Jul/89 - Dec/92: Steam Drive
- Jan/93 - Dec/94: Heat Scavenging Waterflood

Overall, the cyclic production performance had an average incremental recovery of 17 percent over the three-year cycle phase. The average calendar day oil rates were slightly less than the 11.9 cubic meters per day originally forecast with oil steam ratios higher than the 0.55 forecast.

The next phase of the pilot is to follow-up the four cycle steam stimulation phase with a steam drive by way of continuous injection into the central well. Performance thus far has been encouraging with production being equal to or better than forecast and slightly higher than at the end of the cyclic phase. The steam drive performance in 1991 and 1992 will be important in determining the ultimate recovery process and pattern size to be chosen for the pool.

Project Cost: $14 million capital, $2.5 million per year operating

PR SPRING PROJECT—Enercor and Solv-Ex Corporation. (T-540)

The PR Spring Tar Sand Project, a joint venture between Solv-Ex Corporation (the operator) and Enercor, was formed for the purpose of mining tar sand from leases in the PR Spring area of Utah and extracting the contained hydrocarbon for sale in the heavy oil markets.

The project's surface mine will utilize a standard box-cut advancing pit concept with a pit area of 20 acres. Approximately 1,600 acres will be mined during the life of the project. Exploratory drilling has indicated oil reserves of 58 million barrels with an average grade of 7.9 percent by weight bitumen.

The proprietary oil extraction process to be used in the project was developed by Solv-Ex in its laboratories and pilot plant and claims the advantages of high recovery of bitumen, low water requirements, acceptable environmental effects and low economical capital and operating costs. Process optimization and scale-up testing is currently underway for the Solv-Ex/Shell Canada Project which uses the same technology.

The extraction plant for the project has been designed to process tar sand ore at a feed rate of 500 tons per hour and produce net product oil for sale at a rate of 4,663 barrels per day over 330 operating days per year.

In August 1985 the sponsors requested loan and price guarantees totaling $230,947,000 under the United States Synthetic Fuels Corporation's (SFC's) solicitation for tar sands mining and surface processing projects. On November 19, 1985 the SFC determined that the project was qualified for assistance under the terms of the solicitation. However, the SFC was abolished by Congress on December 19, 1985 before financial assistance was awarded to the project.

The sponsors are evaluating various product options, including asphalt and combined asphalt/jet fuel. Private financing and equity participation for the project are being sought.

Project Cost: $158 million (Synthetic crude option)
$90 million (Asphalt option)
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

SOARS LAKE HEAVY OIL PILOT - Amoco Canada Petroleum Company Ltd. (T-590)

Amoco Canada in July, 1988 officially opened the company's 16-well heavy oil pilot facilities located on the Elizabeth Metis Settlement south of Cold Lake. The project is designed to test cyclic steam simulation process.

Amoco Canada has been actively evaluating the heavy oil potential of its Soars Lake leases since 1965 when the company drilled two successful wells. The company now has 49 active or shut-in wells at this site with most having been drilled since 1985. The heavy oil reservoir at Soars Lake is located in the Sparky formation at a depth of 1,500 feet.

In the summer of 1987, Amoco began drilling 15 slant wells for the project. One vertical well already drilled at the site was included in the plans. The wells are oriented in a square 10 acre/well pattern along NE-SW rows.

The injection scheme initially called for steaming two wells simultaneously with the project's two 25 MMBTU/hr generators. However, severe communication developed immediately along the NE-SW direction resulting in production problems. Although this fracture trend was known to exist, communication was not expected over the 660 feet between the wells' bottomhole locations. Steam splitters were installed to allow steaming of 4 wells simultaneously along the NE-SW direction. Four cycles of steam injection have been completed and although production problems have decreased, reservoir performance remains poor. The short-term strategy for the pilot calls for an extended production cycle to create some voidage in the reservoir prior to any further steam stimulations.

Further to extending the production cycle of the original pilot wells, Amoco Canada is currently testing the primary production potential of Soars Lake with six new wells drilled in June 1991. To this end Amoco Canada and the government of Alberta are negotiating an agreement on project royalties for primary production. Initial results from the six new wells have been encouraging. Additional drilling is anticipated during late 1991 or early 1992.

Project Cost: $40 million

STEEPBANK PILOT PROJECT - Chevron Canada Resources (T-40)

Chevron Canada Resources has started a new pilot project utilizing the HASDrive (Heated Annulus Steam Drive) process to recover bitumen from the Athabasca Oil Sands. The pilot plant is located on Chevron's Steepbank oil sands lease located about 30 miles northeast to Fort McMurray, Alberta, Canada.

In the HASDrive process, a horizontal wellbore is drilled into the oil sands formation. Steam is circulated in the cased wellbore thereby transferring heat into the oil sand. Two vertical injection wells are used to inject steam into the formation at points along the heated horizontal channel (annulus), driving the heated bitumen toward a production well placed between the injection wells.

Operations commenced November 1, 1991 with steam circulation in the horizontal well. Four pilot wells were drilled in 1991, including a 1,600 foot horizontal section. In addition to the vertical producing well and two steam injectors, five temperature observation wells were drilled.

Project Cost: $12.7 million

TACIUK PROCESSOR PILOT - AOSTRA and The UMA Group Ltd. (T-610)

AOSTRA has built a pilot for an extraction and partial upgrading process located in southeast Calgary, Alberta. The pilot plant finished construction in March 1978 at a cost of $1 million. The process was invented by William Taciuk of The UMA Group. Development is being done by UMATAC Industrial Processes Ltd., a subsidiary of The UMA Group. Funding is by the Alberta Oil Sands Technology and Research Authority (AOSTRA). The processor consists of a rotating kiln which houses heat exchange, cracking and combustion processes. The processor yields cracked bitumen vapors and dry sand tailings. The pilot plant, which processed 5 tons of Athabasca oil sand per hour, has completed testing and demonstration.

Information agreements were made with a major oil company and with a joint-venture company between two majors. The information agreements provide, in exchange for a funding contribution to the project, full rights for evaluation purposes to the information generated by the project during the pilot phase.

A substantial increase in coke burning capacity and in the length of pilot run was demonstrated in the 1982 season. Recycle of the heaviest fraction of the extracted oil to produce an oil suitable for hydrotreating has been practiced. The oil product is similar to that of a fluid coker, so the process would replace both the extraction and primary upgrading steps of the process (hot water and coking) used at existing commercial plants.

The next stage is a demonstration scale AOSTRA Taciuk Processor (ATP) plant, sized at 100 tons per hour feed capacity and located in the Athabasca Oil Sands operating area. The design and proposal for this facility were completed in 1985, but the project has not proceeded because of the unfavorable economic climate for oil industry capital investment.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

A comparable demonstration scale project is being considered for a semi-commercial plant to study and demonstrate the ATP System for producing oil from oil shale at a deposit in Australia. The design of this facility is underway, and is for a throughput capacity of 6,000 tons per day of oil shale feed. Construction is not yet committed, but is planned for 1993 or later. (See Stuart Oil Shale Project in oil shale status section).

A third area of application of the technology has been developed in the past 7 years, which is its use for remediation of oily soils and sludges. In this area, the ATP has progressed to commercialization. The first ATP waste treatment was built in 1989 for Soil-Tech, Inc. which is the United States licensee for the use of the technology in waste treatment. This plant has successfully treated 42,000 tons of PCB contaminated soil to remove the PCB contaminant. The removal treatment was by chemical dechlorination within the ATP unit and met standards of 2 ppm or less PCB for the remediated soil.

The 10 ton/hour soiltech plant is presently committed for use at the Waukegan Harbor Superfund site in Illinois. This is also a PCB treatment project, for the extraction of PCBs from 17,000 cubic yards of drained harbor silts.

In February 1991, AOSTRA commissioned the construction of a 5 ton per hour portable unit for use in Canada. It will to be available in the summer of 1992 to demonstrate oil production from tar sands and cleanup of oily waste sites in Canada.

Project Cost To Date: C$24 million (AOSTRA)

TANGLEFLAGS NORTH - Sceptre Resources Limited and Murphy Oil Canada Ltd. (T-620)

The project, located some 35 kilometers northeast of Lloydminster, Saskatchewan, near Paradise Hill, involves the first horizontal heavy oil well in Saskatchewan. Production from horizontal oil wells is expected to dramatically improve the recovery of heavy oil in the Lloydminster region.

The Tangleflags North Pilot Project is employing drilling methods similar to those used by Esso Resources Canada Ltd. in the Norman Wells oil field of the Northwest Territories and at Cold Lake, Alberta. The combination of the 500-meter horizontal production well and steamflood technology is expected to increase recovery at the Tangleflags North Pilot Project from less than one percent of the oil in place to up to 50 percent.

The governments of Canada and Saskatchewan provided $3.8 million in funding under the terms of the Canada-Saskatchewan Heavy Oil Fossil Fuels Research Program.

Estimates indicate sufficient reserves exist in the vicinity of the pilot to support commercial development with a peak gross production rate of 6,200 barrels of oil per day. Project life is estimated at 15 years.

The Tangleflags pilot has advanced to the continuous steam injection phase. With one horizontal well and four vertical steam injection wells in place, the project was producing at rates in excess of 1,000 barrels of oil per day by mid 1990. Cumulative production to the middle of 1990 was 425,000 barrels. Production has reached peak rates in excess of 1,600 barrels per day. The expansion of the pilot project into a commercial operation involving 14 horizontal wells will hinge on future crude oil prices.

The strong performance of the initial well prompted Sceptre to initiate a six-well commercial phase scheduled for completion by the end of 1992. For this purpose a second horizontal producer well and an additional vertical injector well were drilled in the fourth quarter of 1990. Facilities were expanded to generate more steam and handle increased production volumes in early 1991. Cumulative oil production to the end of 1991 was 1,303,000 barrels.

Project Cost: $12.3 million invested to 1992

TAR SAND TRIANGLE - Kirkwood Oil and Gas (T-630)

Kirkwood Oil and Gas drilled some 16 coreholes by the end of 1982 to evaluate their leases in the Tar Sand Triangle in south central Utah. They are also evaluating pilot testing of inductive heating for recovery of bitumen. A combined hydrocarbon unit, to be called the Gunsight Butte unit, is presently being formed to include Kirkwood and surrounding leases within the Tar Sand Triangle Special Tar Sand Area (STSA).

Kirkwood is also active in three other STSAs as follows:

- Raven Ridge-Rimrock—Kirkwood Oil and Gas has received a combined hydrocarbon lease for 640 acres in the Raven Ridge-Rim Rock Special Tar Sand Area.
- Hill Creek and San Rafael Swell—Kirkwood Oil and Gas is also in the process of converting leases in the Hill Creek and San Rafael Swell Special Tar Sand Areas.

Kirkwood Oil and Gas has applied to convert over 108,000 acres of oil and gas leases to combined hydrocarbon leases. With these conversions Kirkwood will hold more acreage over tar sands in Utah than any other organization.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since March 1992)

R & D PROJECTS (Continued)

The project has been put on temporary hold.

Project Cost: Unknown

UNDERGROUND TEST FACILITY — Alberta Oil Sands Technology and Research Authority, Federal Department of Energy, Mines and Resources (CANMET), Chevron Canada Resources Limited, Esso Resources Canada Limited, Conoco Canada Limited, Mobil Oil Canada Ltd., Petro-Canada Inc., Shell Canada Ltd., Amoco Canada Petroleum Company, Ltd., Japex Oil Sands Ltd. (T-650)

The Underground Test Facility (UTF) was constructed by AOSTRA during 1984-1987, for the purpose of testing novel in situ recovery technologies based on horizontal wells, in the Athabasca oil sands. The facility is located 70 kilometers northwest of Fort McMurray, and consists of two access/ventilation shafts, three meters in diameter and 185 meters deep, plus a network of tunnels driven in the Devonian limestone that underlies the McMurray pay. A custom drilling system has been developed to drill wells upward from the tunnels, starting at a shallow angle, and then horizontally through the pay, to lengths of up to 1,000 meters.

Two processes were selected for initial testing: steam assisted gravity drainage (SAGD), and Chevron’s proprietary HASDrive process. Steaming of both test patterns commenced in December 1987 and continued up to early 1990. HASDrive was shut in April 1990 and the SAGD was to continue producing in a blowdown phase until the fall of 1990.

Both tests were technical successes. In the case of the Phase A SAGD test, a commercially viable combination of production rates, steam/oil ratios, and ultimate recovery was achieved. Complete sand control was demonstrated, and production flowed to surface for most of the test.

Construction of the Phase B SAGD test commenced in the spring of 1990 with the drivage of 550 meters of additional tunnel, for a total of about 1,500 meters. Phase B is a direct scale up of the Phase A test, using what is currently thought to be the economic optimum well length and spacing. The test consists of three pairs of horizontal wells, with completed lengths of 600 meters and 70 meter spacing between pairs. Each well pair consists of a producer placed near the base of the pay, and an injector about five meters above the producer. All six wells were successfully drilled in 1990. The rest of Phase B operations are to be completed by 1994. Phase A produced over 130,000 barrels of bitumen.

Phase B steaming, to commence in September 1991, is expected to continue until 1994. A decision regarding expansion to commercial production will be made after this period. Two thousand barrels per day of bitumen are expected to be produced by this method. Production is slated to begin in September 1992.

AOSTRA states that this new method of bitumen production is starting to look like a major technological breakthrough and that bitumen may eventually be produced for under C$7 per barrel, which would be less costly than most current in situ bitumen production.

In 1992, AOSTRA applied to expand its experimental operations at the UTF. The project entails six new horizontal wells to test the production capabilities of longer wellbores reaching up to 600 meters. Bitumen production rates at the site are expected to increase from 400 to 500 cubic meters per day.

Japex Oil Sands Ltd. of Calgary will invest $6.5 million in the UTF over the next several years. Japex will take an active role in the management of the project.

Project Cost: $150 million
<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsor</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aberfieldy Project</td>
<td>Husky Oil Operations, Ltd.</td>
<td>March 1983; page 3-33</td>
</tr>
<tr>
<td>A.D.I. Chemical Extraction</td>
<td>Aarian Development, Inc.</td>
<td>December 1983; page 3-56</td>
</tr>
<tr>
<td>Alsands Project</td>
<td>Shell Canada Resources, Ltd. Petro-Canada</td>
<td>September 1982; page 3-35</td>
</tr>
<tr>
<td></td>
<td>Gulf Canada</td>
<td></td>
</tr>
<tr>
<td>Ardmore Thermal Pilot Plant</td>
<td>Union Texas of Canada, Ltd.</td>
<td>September 1989; page 3-9</td>
</tr>
<tr>
<td>Asphalt Ridge Tar Sands Pilot</td>
<td>Sohio</td>
<td>December 1986; page 3-51</td>
</tr>
<tr>
<td>Asphalt Ridge Pilot Plant</td>
<td>Enercor</td>
<td>September 1984; page T-7</td>
</tr>
<tr>
<td></td>
<td>Mobil University of Utah</td>
<td></td>
</tr>
<tr>
<td>Athabasca Project</td>
<td>Shell Canada Limited Solv-Ex Corp.</td>
<td>September 1988; page 3-50</td>
</tr>
<tr>
<td>Beaver Crossing Thermal Recovery Pilot</td>
<td>Chevron Canada Resources</td>
<td>December 1988; page 3-67</td>
</tr>
<tr>
<td>Block One Project</td>
<td>Amoco Canada Petroleum Company Ltd. AOSTRA</td>
<td>September 1984; page T-8</td>
</tr>
<tr>
<td></td>
<td>Petro-Canada Ltd.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Shell Canada Resources</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Suncor, Inc.</td>
<td></td>
</tr>
<tr>
<td>Burnt Hollow Tar Sand Project</td>
<td>Glenda Exploration &amp; Development Corp.</td>
<td>September 1984; page T-8</td>
</tr>
<tr>
<td></td>
<td>Kirkwood Oil &amp; Gas Company</td>
<td></td>
</tr>
<tr>
<td>Burnt Lake</td>
<td>Suncor</td>
<td>December 1986; page 3-43</td>
</tr>
<tr>
<td>BVI Cold Lake Pilot</td>
<td>AOSTRA</td>
<td>March 1991; page 3-44</td>
</tr>
<tr>
<td></td>
<td>Bow Valley Industries, Ltd.</td>
<td></td>
</tr>
<tr>
<td>California Tar Sands Development Project</td>
<td>California Tar Sands Development Company</td>
<td>September 1989; page 3-42</td>
</tr>
<tr>
<td>Calsyn Project</td>
<td>California Synfuels Research Corporation</td>
<td>March 1984; page 3-34</td>
</tr>
<tr>
<td></td>
<td>AOSTRA</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dynalectron Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ralph M. Parsons Company</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tenneco Oil Company</td>
<td></td>
</tr>
<tr>
<td>CANMET Hydrocracking Process</td>
<td>Petro-Canada</td>
<td>March 1992; page 3-50</td>
</tr>
<tr>
<td></td>
<td>Partec Lavalin, Inc.</td>
<td></td>
</tr>
<tr>
<td>Canstar</td>
<td>Nova</td>
<td>March 1987; page 3-29</td>
</tr>
<tr>
<td></td>
<td>Petro-Canada</td>
<td></td>
</tr>
<tr>
<td>Cat Canyon Steamflood Project</td>
<td>Getty Oil Company</td>
<td>December 1983; page 3-58</td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Cedar Camp Tar Sand Project</td>
<td>Enercor</td>
<td>June 1987; page 3-55</td>
</tr>
<tr>
<td></td>
<td>Mono Power</td>
<td></td>
</tr>
<tr>
<td>Chaparrosa Ranch Tar Sand Project</td>
<td>Chaparrosa Oil Company</td>
<td>March 1985; page 3-42</td>
</tr>
<tr>
<td>Charlotte Lake Project</td>
<td>Canadian Worldwide Energy Ltd.</td>
<td>September 1988; page 3-61</td>
</tr>
<tr>
<td>Chemech Project</td>
<td>Chemech</td>
<td>December 1985; page 3-51</td>
</tr>
<tr>
<td>Chetopa Project</td>
<td>EOR Petroleum Company</td>
<td>December 1983; page 3-59</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, JUNE 1992
<table>
<thead>
<tr>
<th>Project Name</th>
<th>Company/Institution</th>
<th>Date/Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cold Lake Pilot Project</td>
<td>Tetra Systems</td>
<td>December 1979; page 3-31</td>
</tr>
<tr>
<td>Deepsteam Project</td>
<td>Gulf Canada Resources</td>
<td>March 1984; page 3-41</td>
</tr>
<tr>
<td>Enpex Syntaro Project</td>
<td>Sandia Laboratories United States Department of Energy</td>
<td>March 1989; page 3-63</td>
</tr>
<tr>
<td>Falcon Sciences Project</td>
<td>Enpex Corporation</td>
<td>December 1985; page 3-38</td>
</tr>
<tr>
<td>Foxtorn N. W. In Situ Wet Combustion</td>
<td>Mobil Oil Canada, Ltd.</td>
<td>December 1989; page 3-63</td>
</tr>
<tr>
<td>Grossmont Thermal Recovery Project</td>
<td>Unocal Canada Ltd.</td>
<td>December 1988; page 3-71</td>
</tr>
<tr>
<td>HOP Kern River Commercial</td>
<td>Ladd Petroleum Corporation</td>
<td>June 1985; page 3-51</td>
</tr>
<tr>
<td>Ipiatik East Project</td>
<td>Alberta Energy Company Amoco Canada Petroleum Company, Ltd.</td>
<td>March 1992; page 3-54</td>
</tr>
<tr>
<td>Ipiatik Lake Project</td>
<td>Alberta Energy Company and Petro-Canada</td>
<td>December 1986; page 3-63</td>
</tr>
<tr>
<td>Jet Leaching Project</td>
<td>BP Resources Canada Ltd.</td>
<td>June 1991; page 3-57</td>
</tr>
<tr>
<td>Kenoco Project</td>
<td>Kenoco</td>
<td>December 1991; page 3-52</td>
</tr>
<tr>
<td>Kentucky Tar Sands Project</td>
<td>Texas Gas Development</td>
<td>June 1985; page 3-52</td>
</tr>
<tr>
<td>Lloydminster Fireflood</td>
<td>Murphy Oil Company, Ltd.</td>
<td>December 1983; page 3-63</td>
</tr>
<tr>
<td>Manatokan Project</td>
<td>Canada Cities Service Westcoast Petroleum</td>
<td>September 1982; page 3-43</td>
</tr>
<tr>
<td>Marguerite Lake 'B' Unit</td>
<td>AOSTRA BP Resources Canada Ltd.</td>
<td>December 1988; page 3-72</td>
</tr>
<tr>
<td>Meota Steam Drive Project</td>
<td>Conterra Energy Ltd Saskatchewan Oil &amp; Gas Total Petroleum Canada</td>
<td>June 1987; page 3-60</td>
</tr>
<tr>
<td>Mine-Assisted In Situ Project</td>
<td>Canada Cities Service Esso Resources Canada Ltd. Gulf Canada Resources, Inc. Husky Oil Corporations, Ltd. Petro-Canada</td>
<td>December 1983; page 3-64</td>
</tr>
<tr>
<td>MRL Solvent Process</td>
<td>C &amp; A Companies Minerals Research Ltd.</td>
<td>March 1983; page 3-41</td>
</tr>
<tr>
<td>Muriel Lake</td>
<td>Canadian Worldwide Energy</td>
<td>June 1987; page 3-61</td>
</tr>
<tr>
<td>North Kinsella Heavy Oil</td>
<td>Petro-Canada</td>
<td>June 1985; page 3-58</td>
</tr>
<tr>
<td>Peace River In Situ Pilot</td>
<td>Amoco Canada Petroleum AOSTRA Shell Canada Limited Shell Explorer Limited</td>
<td>June 1987; page 3-61</td>
</tr>
</tbody>
</table>
### STATUS OF OIL SANDS PROJECTS

#### COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Company/Institution</th>
<th>Status/Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porta-Plants Project</td>
<td>Porta-Plants Inc.</td>
<td>September 1986; page 3-50</td>
</tr>
<tr>
<td>Primrose Project</td>
<td>Japan Oil Sands Company</td>
<td>September 1984; page T-16</td>
</tr>
<tr>
<td></td>
<td>Noreen Energy Resources Ltd.</td>
<td></td>
</tr>
<tr>
<td>Primrose-Kirby Project</td>
<td>Petro-Canada</td>
<td>June 1986; page 3-56</td>
</tr>
<tr>
<td>RAPAD Bitumen Upgrading</td>
<td>Research Association for Petroleum Alternatives</td>
<td>December 1991; page 3-55</td>
</tr>
<tr>
<td>Ras Gharib Thermal Pilot</td>
<td>General Petroleum Company of Egypt</td>
<td>March 1990; page 3-54</td>
</tr>
<tr>
<td>Resdelin Project</td>
<td>Gulf Canada Resources Inc.</td>
<td>March 1983; page 3-43</td>
</tr>
<tr>
<td>R. F. Heating Project</td>
<td>IIT Research Institute</td>
<td>March 1983; page 3-43</td>
</tr>
<tr>
<td></td>
<td>Halliburton Services</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>RTR Pilot Project</td>
<td>RTR Oil Sands (Alberta) Ltd.</td>
<td>March 1991; page 3-53</td>
</tr>
<tr>
<td>Sandalta</td>
<td>Gulf Canada Resources Ltd.</td>
<td>March 1992; page 3-58</td>
</tr>
<tr>
<td></td>
<td>Home Oil Company, Ltd.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Mobil Oil Canada Ltd.</td>
<td></td>
</tr>
<tr>
<td>Santa Fe Tar Sand Triangle</td>
<td>Altex Oil Corporation</td>
<td>December 1986; page 3-60</td>
</tr>
<tr>
<td></td>
<td>Santa Fe Energy Company</td>
<td></td>
</tr>
<tr>
<td>Santa Rosa Oil Sands Project</td>
<td>Solv-Ex Corporation</td>
<td>March 1985; page 3-45</td>
</tr>
<tr>
<td>Sarnia-London Road Mining Assisted Project</td>
<td>Devran Petroleum</td>
<td>December 1988; page 3-62</td>
</tr>
<tr>
<td></td>
<td>Shell Canada</td>
<td></td>
</tr>
<tr>
<td>South Kinsella (Kinsella B)</td>
<td>Dome Petroleum</td>
<td>December 1988; page 3-76</td>
</tr>
<tr>
<td>South Texas Tar Sands</td>
<td>Conoco</td>
<td>June 1987; page 3-64</td>
</tr>
<tr>
<td>Texaco Athabasca Pilot</td>
<td>Texaco Canada Resources</td>
<td>June 1987; page 3-66</td>
</tr>
<tr>
<td>Tucker Lake Pilot Project</td>
<td>Husky Oil Operations Ltd.</td>
<td>December 1991; page 3-57</td>
</tr>
<tr>
<td>Ultrasonic Wave Extraction</td>
<td>Western Tar Sands</td>
<td>June 1987; page 3-66</td>
</tr>
<tr>
<td>Vaca Tar Sand Project</td>
<td>Santa Fe Energy Company</td>
<td>March 1982; page 3-43</td>
</tr>
<tr>
<td>Wabasca Fireflood Project</td>
<td>Gulf Canada Resources, Inc.</td>
<td>September 1980; page 3-61</td>
</tr>
<tr>
<td>Whiterocks Oil Sand Project</td>
<td>Enercor</td>
<td>December 1983; page 3-55</td>
</tr>
<tr>
<td></td>
<td>Hinge-line Overthrust Oil &amp; Gas Corp.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Rocky Mountain Exploration Company</td>
<td></td>
</tr>
<tr>
<td>Wolf Lake Oxygen Project</td>
<td>BP Canada Resources</td>
<td>September 1988; page 3-70</td>
</tr>
<tr>
<td></td>
<td>Petro Canada</td>
<td></td>
</tr>
<tr>
<td>*200° Sand Steamflood Demonstration Project</td>
<td>Santa Fe Energy Company</td>
<td>June 1986; page 3-62</td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
</tbody>
</table>
## INDEX OF COMPANY INTERESTS

<table>
<thead>
<tr>
<th>Company or Organization</th>
<th>Project Name</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta Energy Company</td>
<td>Burnt Lake Project</td>
<td>3-30</td>
</tr>
<tr>
<td></td>
<td>Caribou Lake Pilot Project</td>
<td>3-41</td>
</tr>
<tr>
<td></td>
<td>Primrose Lake Commercial Project</td>
<td>3-36</td>
</tr>
<tr>
<td></td>
<td>Syncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td>Alberta Oil Sands Equity</td>
<td>Oslo Project</td>
<td>3-34</td>
</tr>
<tr>
<td></td>
<td>Syncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td>Alberta Oil Sands Technology and Research Authority (AOSTRA)</td>
<td>Athabasca In Situ Pilot Plant</td>
<td>3-40</td>
</tr>
<tr>
<td></td>
<td>Donor Refined Bitumen Process</td>
<td>3-42</td>
</tr>
<tr>
<td></td>
<td>GLISP Project</td>
<td>3-44</td>
</tr>
<tr>
<td></td>
<td>Provost Upper Mannville Heavy Oil Steam Pilot</td>
<td>3-47</td>
</tr>
<tr>
<td></td>
<td>Taciuk Processor Pilot</td>
<td>3-48</td>
</tr>
<tr>
<td></td>
<td>Underground Test Facility Project</td>
<td>3-50</td>
</tr>
<tr>
<td>Amoco Canada Petroleum Company, Ltd.</td>
<td>Elk Point</td>
<td>3-32</td>
</tr>
<tr>
<td></td>
<td>GLISP Project</td>
<td>3-44</td>
</tr>
<tr>
<td></td>
<td>Lindbergh Commercial Project</td>
<td>3-33</td>
</tr>
<tr>
<td></td>
<td>Lindbergh Thermal Project</td>
<td>3-45</td>
</tr>
<tr>
<td></td>
<td>Morgan Combination Thermal Drive Project</td>
<td>3-45</td>
</tr>
<tr>
<td></td>
<td>Primrose Lake Commercial Project</td>
<td>3-36</td>
</tr>
<tr>
<td></td>
<td>Soars Lake Heavy Oil Pilot</td>
<td>3-48</td>
</tr>
<tr>
<td></td>
<td>Underground Test Facility</td>
<td>3-50</td>
</tr>
<tr>
<td></td>
<td>Wolf Lake Project</td>
<td>3-39</td>
</tr>
<tr>
<td>Amoco Production Company</td>
<td>Sunnyside Project</td>
<td>3-37</td>
</tr>
<tr>
<td>Buenaventura Resource Corp.</td>
<td>Buenaventura Cold Process Pilot</td>
<td>3-41</td>
</tr>
<tr>
<td>Canada Centre For Mineral &amp; Energy Technology</td>
<td>Underground Test Facility</td>
<td>3-50</td>
</tr>
<tr>
<td>Canadian Hunter Exploration</td>
<td>Burnt Lake Project</td>
<td>3-30</td>
</tr>
<tr>
<td>Canadian Occidental Petroleum, Ltd.</td>
<td>Eyehill In Situ Combustion Project</td>
<td>3-43</td>
</tr>
<tr>
<td></td>
<td>Hangingstone Project</td>
<td>3-44</td>
</tr>
<tr>
<td></td>
<td>Oslo Project</td>
<td>3-34</td>
</tr>
<tr>
<td></td>
<td>Provost Upper Mannville Heavy Oil Steam Pilot</td>
<td>3-47</td>
</tr>
<tr>
<td></td>
<td>Syncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td>Canadian Worldwide Energy Corp.</td>
<td>Fort Kent Thermal Project</td>
<td>3-43</td>
</tr>
<tr>
<td>CANMET</td>
<td>Underground Test Facility</td>
<td>3-50</td>
</tr>
<tr>
<td>C-H Synfuels Ltd.</td>
<td>C-H Synfuels Dredging Project</td>
<td>3-41</td>
</tr>
<tr>
<td>Chevron Canada Resources Ltd.</td>
<td>Steepbank HASDrive Pilot Project</td>
<td>3-48</td>
</tr>
<tr>
<td></td>
<td>Underground Test Facility</td>
<td>3-50</td>
</tr>
<tr>
<td>Conoco Canada Ltd.</td>
<td>Underground Test Facility</td>
<td>3-50</td>
</tr>
<tr>
<td>Consumers Cooperative Refineries Ltd.</td>
<td>NewGrade Heavy Oil Upgrader</td>
<td>3-34</td>
</tr>
<tr>
<td>CS Resources</td>
<td>Eyehill In Situ Combustion Project</td>
<td>3-43</td>
</tr>
<tr>
<td></td>
<td>Pelican-Wahasca Project</td>
<td>3-46</td>
</tr>
<tr>
<td></td>
<td>Pelican Lake Project</td>
<td>3-46</td>
</tr>
<tr>
<td>Devran Petroleum Ltd.</td>
<td>Pelican Lake Project</td>
<td>3-46</td>
</tr>
<tr>
<td>Electromagnetic Oil Recovery Inc.</td>
<td>Electromagnetic Well Stimulation Process</td>
<td>3-31</td>
</tr>
<tr>
<td>Enercor</td>
<td>PR Spring Project</td>
<td>3-47</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, JUNE 1992
## STATUS OF OIL SANDS PROJECTS

### INDEX OF COMPANY INTERESTS (Continued)

<table>
<thead>
<tr>
<th>Company or Organization</th>
<th>Project Name</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Esso Resources Canada Ltd.</td>
<td>Athabasca In Situ Pilot Project</td>
<td>3-40</td>
</tr>
<tr>
<td></td>
<td>Cold Lake Project</td>
<td>3-30</td>
</tr>
<tr>
<td></td>
<td>Esso Cold Lake Pilot Projects</td>
<td>3-42</td>
</tr>
<tr>
<td></td>
<td>Hanging Stone Project</td>
<td>3-44</td>
</tr>
<tr>
<td></td>
<td>Oslo Project</td>
<td>3-34</td>
</tr>
<tr>
<td></td>
<td>Provost Upper Mannville Heavy Oil Steam Pilot</td>
<td>3-47</td>
</tr>
<tr>
<td></td>
<td>Suncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td>GNC Energy Corporation</td>
<td>Sunnyside Tar Sands Project</td>
<td>3-37</td>
</tr>
<tr>
<td>Greenwich Oil Corporation</td>
<td>Forest Hill Project</td>
<td>3-33</td>
</tr>
<tr>
<td>Gulf Canada Resources Ltd.</td>
<td>Donor Refined Bitumen Process</td>
<td>3-42</td>
</tr>
<tr>
<td></td>
<td>Oslo Project</td>
<td>3-34</td>
</tr>
<tr>
<td></td>
<td>Suncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td>HBOG Oil Sands Partnership</td>
<td>Suncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td>Hudson's Bay Oil and Gas</td>
<td>Batrurum In Situ Wet Combustion Project</td>
<td>3-40</td>
</tr>
<tr>
<td>Husky Oil Operations, Ltd.</td>
<td>Athabasca In Situ Pilot Project</td>
<td>3-40</td>
</tr>
<tr>
<td></td>
<td>Batrurum In Situ Wet Combustion Project</td>
<td>3-40</td>
</tr>
<tr>
<td></td>
<td>Bi-Provincial Upgrader</td>
<td>3-29</td>
</tr>
<tr>
<td></td>
<td>Caribou Lake Pilot Project</td>
<td>3-41</td>
</tr>
<tr>
<td>James W. Burger and Assoc. Inc.</td>
<td>Asphalt From Tar Sands</td>
<td>3-29</td>
</tr>
<tr>
<td>Japan Canadian Oil Sands Ltd.</td>
<td>Hangingstone Project</td>
<td>3-44</td>
</tr>
<tr>
<td>Kirkwood Oil and Gas Company</td>
<td>Circle Cliffs Project</td>
<td>3-42</td>
</tr>
<tr>
<td></td>
<td>Tar Sand Triangle</td>
<td>3-49</td>
</tr>
<tr>
<td>Koch Exploration Canada</td>
<td>Fort Kent Thermal Project</td>
<td>3-43</td>
</tr>
<tr>
<td>L'Association pour la Valorization des Huiles Lourdes (ASVAHL)</td>
<td>Donor Refined Bitumen Process</td>
<td>3-42</td>
</tr>
<tr>
<td>Maraven</td>
<td>Orinoco Belt Steam Soak Pilot</td>
<td>3-45</td>
</tr>
<tr>
<td>Mitsubishi Oil Company</td>
<td>Suncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td>Mobil Oil Canada Ltd.</td>
<td>Batrurum In Situ Wet Combustion Project</td>
<td>3-40</td>
</tr>
<tr>
<td></td>
<td>Celtic Heavy Oil Pilot Project</td>
<td>3-41</td>
</tr>
<tr>
<td></td>
<td>Cold Lake Steam Stimulation Program</td>
<td>3-42</td>
</tr>
<tr>
<td></td>
<td>Iron River Pilot Project</td>
<td>3-44</td>
</tr>
<tr>
<td></td>
<td>Underground Test Facility</td>
<td>3-50</td>
</tr>
<tr>
<td>Murphy Oil Canada Ltd.</td>
<td>Eyehill In Situ Combustion Project</td>
<td>3-43</td>
</tr>
<tr>
<td></td>
<td>Lindbergh Commercial Thermal Recovery Project</td>
<td>3-33</td>
</tr>
<tr>
<td></td>
<td>Lindbergh Steam Project</td>
<td>3-44</td>
</tr>
<tr>
<td></td>
<td>Provost Upper Mannville Heavy Oil Steam Pilot</td>
<td>3-47</td>
</tr>
<tr>
<td></td>
<td>Tangleflags North</td>
<td>3-49</td>
</tr>
<tr>
<td>NewGrade Energy Inc.</td>
<td>NewGrade Heavy Oil Upgrader</td>
<td>3-34</td>
</tr>
<tr>
<td>Norcen Energy Resources Ltd.</td>
<td>Provost Upper Mannville Heavy Oil Steam Pilot Project</td>
<td>3-47</td>
</tr>
<tr>
<td>Ontario Energy Resources Ltd.</td>
<td>Suncor, Inc. Oil Sands Group</td>
<td>3-36</td>
</tr>
<tr>
<td>PanCanadian Petroleum</td>
<td>Elk Point Oil Sands Project</td>
<td>3-32</td>
</tr>
<tr>
<td></td>
<td>Oslo Project</td>
<td>3-34</td>
</tr>
<tr>
<td></td>
<td>Suncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td>Company or Organization</td>
<td>Project Name</td>
<td>Page</td>
</tr>
<tr>
<td>-----------------------------------------</td>
<td>-------------------------------------------------------</td>
<td>------</td>
</tr>
<tr>
<td>Petro-Canada</td>
<td>Daphne Project</td>
<td>3-31</td>
</tr>
<tr>
<td></td>
<td>GLISP Project</td>
<td>3-44</td>
</tr>
<tr>
<td></td>
<td>Hangingstone Project</td>
<td>3-44</td>
</tr>
<tr>
<td></td>
<td>Oslo Project</td>
<td>3-34</td>
</tr>
<tr>
<td></td>
<td>Syncrude Canada Ltd.</td>
<td>3-38</td>
</tr>
<tr>
<td></td>
<td>Underground Test Facility</td>
<td>3-50</td>
</tr>
<tr>
<td>Petroleos de Venezuela SA</td>
<td>Orimulsion Project</td>
<td>3-34</td>
</tr>
<tr>
<td>Saskatchewan Government</td>
<td>NewGrade Heavy Oil Upgrader</td>
<td>3-34</td>
</tr>
<tr>
<td>Saskoil</td>
<td>Batrum In Situ Wet Combustion Project</td>
<td>3-40</td>
</tr>
<tr>
<td>Sceptre Resources Ltd.</td>
<td>Tangleflags North</td>
<td>3-49</td>
</tr>
<tr>
<td>Shell Canada, Ltd.</td>
<td>Peace River Complex</td>
<td>3-35</td>
</tr>
<tr>
<td></td>
<td>Scotford Synthetic Crude Refinery</td>
<td>3-36</td>
</tr>
<tr>
<td></td>
<td>Underground Test Facility</td>
<td>3-50</td>
</tr>
<tr>
<td>Solv-Ex Corporation</td>
<td>Bitumount Project</td>
<td>3-50</td>
</tr>
<tr>
<td></td>
<td>PR Spring Project</td>
<td>3-47</td>
</tr>
<tr>
<td>Suncor, Inc.</td>
<td>Burnt Lake Project</td>
<td>3-30</td>
</tr>
<tr>
<td></td>
<td>Fort Kent Thermal Project</td>
<td>3-43</td>
</tr>
<tr>
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<td>Suncor, Inc. Oil Sands Group</td>
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</tr>
<tr>
<td>Sun Company, Inc.</td>
<td>Suncor, Inc. Oil Sands Group</td>
<td>3-36</td>
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<td>Synco Energy Corporation</td>
<td>Synco Sunnyside Project</td>
<td>3-38</td>
</tr>
<tr>
<td>Texaco Canada Petroleum</td>
<td>Frog Lake Project</td>
<td>3-43</td>
</tr>
<tr>
<td>Texaco Inc.</td>
<td>Diatomaceous Earth Project</td>
<td>3-31</td>
</tr>
<tr>
<td>Three Star Drilling and Producing Corp.</td>
<td>Three Star Oil Mining Project</td>
<td>3-39</td>
</tr>
<tr>
<td>Uentech Corporation</td>
<td>Electromagnetic Well Stimulation Process</td>
<td>3-31</td>
</tr>
<tr>
<td>Underwood McLellan &amp; Associates (UMA Group)</td>
<td>Taciuk Processor Pilot</td>
<td>3-48</td>
</tr>
<tr>
<td>Unocal Canada, Ltd.</td>
<td>Batrum In Situ Wet Combustion Project</td>
<td>3-40</td>
</tr>
<tr>
<td>Union of Soviet Socialist Republics</td>
<td>Yarega Mine-Assisted Project</td>
<td>3-40</td>
</tr>
<tr>
<td>Veba Oel AG</td>
<td>Orimulsion Project</td>
<td>3-34</td>
</tr>
</tbody>
</table>
PROJECT ACTIVITIES

ROSEBUD SYNCOAL COMES ONSTREAM

The Rosebud Syncoal Partnership project, located near the town of Colstrip in southeastern Montana, is now in startup following a construction period which was completed ahead of schedule.

This project is a joint effort between Western Energy Company, a subsidiary of Montana Power, and the NRG Group, a nonregulated subsidiary of Northern States Power Company.

The goal of the project is to demonstrate an advanced thermal drying and physical coal cleaning process that can reduce the moisture and sulfur content of low-rank, subbituminous and lignite coals, thereby enhancing their thermal and environmental values. The plant is located next to Western Energy's Rosebud Mine, one of the United States' largest producing coal mines.

Construction for the project was originally scheduled to take 18 months, but it was completed in just 10 months with much of the work being carried out during the winter.

The company began the process of sending Powder River Basin coal through the plant for cold flow testing on January 30, 1992. Short duration production runs have started and gradual production of the "syncoal" product is now under way. The plant is expected to reach full operation capacity early this year.

This plant, when in continuous operation, will produce 1,000 tons per day, or 300,000 tons per year of upgraded solid fuel. The plant is one-tenth the size of a full commercial-scale facility; however, the processing equipment at the facility is commercial size.

The demonstration plant is fully integrated with a unit train loading facility and an active stockpile that can hold up to 90,000 tons of coal. These facilities allow for the easy shipment of the syncoal product to industrial and utility sites for test burns.

Northern States Power Company's Riverside plant will receive the first 5,000 ton shipment for an initial test burn. Dairyland Power has committed to use the next 5,000 tons for test burns at its Alma Station, and Rosebud Syncoal is presently finalizing plans with other utilities for test burns.

With a sulfur content of only 0.3 percent, the syncoal product can be used in many existing coal-fired plants to meet the strict emissions standards of the Clean Air Amendments Act of 1990. By using syncoal, utilities could avoid the cost of installing additional pollution controls or making boiler modifications. The product is an ideal low-sulfur coal substitute.

An important advantage of the continuous-feed Syncoal process is that it operates at low pressures. Several other coal-upgrading techniques under development require high pressure and relatively expensive pressure vessels for the drying process.

TOMS CREEK PROJECT WILL USE U-GAS PROCESS WITH HOT GAS CLEANUP

Tampella Power Corporation has been chosen by the United States Department of Energy (DOE) to build an integrated gasification combined cycle (IGCC) demonstration facility, known as the Toms Creek IGCC Demonstration Project, in Coeburn, Wise County, Virginia.

The Toms Creek Project will utilize Tampella Power's advanced coal gasification technology to demonstrate improved efficiency for conversion of coal to electric power while significantly reducing \( \text{SO}_2 \) and \( \text{NO}_x \) emissions.

Technology Originally from Institute of Gas Technology (IGT)

In September 1989, Tampella Power signed an agreement with IGT to license U-GAS technology in selected parts of the world and to build a 35 to 60 ton per day U-GAS pilot plant at Tampella Power's new R&D Center in Tampere, Finland. IGT developed the U-GAS process with funding support from DOE, the American Gas Association, and Gas Research Institute. The process can operate with air, oxygen or enriched air to produce either low- or medium-BTU gas from coal, biomass, and other feedstocks.

W. Mojtahedi, et al., of Tampella Power Inc. of Finland and S.K. Gangwal of the Research Triangle Institute of North Carolina discussed the Tanipella IGCC process at the 10th EPRI (Electric Power Research Institute) Conference of Coal Gasification Power Plants held in San Francisco, California in October.

Process Description

Tampella Power's IGCC system incorporates three main parts:

- The gasification plant, including fuel preparation and feeding, gasifier, gas cooling to about 1,020°F and hot gas cleanup

SYNTHETIC FUELS REPORT, JUNE 1992
- The gas turbine plant including gas turbine and the booster compressor heat exchanger system for the gasifier air supply

- The steam cycle including heat recovery steam generator, steam turbine and conventional parts of a steam cycle

Feedstock properties guide the selection of the feeding system. All types of dried fuels can generally be fed pneumatically through lockhopper systems. For coal feeding the simpler paste feeding has also been considered. The sorbent required for in-bed desulfurization is fed by lockhoppers or alternatively mixed with the coal paste. The gasification air is supplied by the gas turbine (air extraction after compressor) through a booster compressor/heat exchanger system. The gasification steam is extracted from the high pressure side of the steam turbine or produced by the gas cooler and fed through the grid of the gasifier.

The gasification system is the U-GAS process, a single stage pressurized fluidized-bed gasifier. The gasifier produces a low-BTU gas to fuel the gas turbine. The bulk of fuel ash and spent sorbent is removed through the bottom of the gasifier.

The elutriated fines from the gasifier are partly separated by cyclones and returned to the bed area of the gasifier. The product gas leaving the gasifier at 1,800 to 1,900°F is cooled to about 1,020°F in a gas cooler heat exchanger. The gas cooler produces saturated steam and is connected to the high pressure side of the steam recovery steam generator.

The hydrogen sulfide content of the product gas is further reduced down to parts per million levels in an external sulfur removal unit. The external sorbent is regenerated by a mixture of air and steam, taken from the excess gas turbine air and from the high pressure extraction steam, respectively. The remainder of the fine particles, elutriated from the gasifier and from the sulfur removal system, are removed from the sulfur-free product gas in a ceramic filter unit at high temperature and pressure. The filter elements are cleaned on-line by back pulsing with high pressure steam. The tail gas from the sorbent regeneration and the fine particles from the filtration unit are recycled to the gasifier. Spent zinc titanate sorbent is removed from the external desulfurization system for disposal.

The clean product gas is burned in the combustion chamber of the gas turbine and the flue gas generated is expanded through the gas turbine. The energy of the gas turbine exhaust gas is utilized in the steam cycle part of the IGCC process, which includes heat recovery steam generator, steam turbine and other features of a steam power generating process.

Gasification

Typical product gas compositions (the main gas components) are shown in Table 1 for the fuels considered by Tampella Power in the on-going IGCC development work.

When gasifying coal, the coal ash is removed from the gasifier in the form of agglomerates, which is a special feature of the U-GAS process.

Hot Gas Cleanup

The high temperature, high pressure gas cleanup is a key component of Tampella Power's IGCC system. Depending on the feedstock to be gasified, different product gas contaminants are of main concern. Generally in coal gasification, sulfur compounds, and in peat gasification, nitrogen compounds, while in the gasification of biomass, tars are the main contaminants to be removed. Gasification fines have to be removed in all these cases.

A two-stage desulfurization of the fuel gas is employed. The bulk of fuel-bound sulfur is removed in the gasifier by means of a desulfurizing agent such as limestone or dolomite.

Post-gasifier desulfurization is undertaken to polish the product gas, i.e., to reduce the remaining H_2S concentration to below 50 ppm. This is accomplished in a two-fluidized-bed reactor system shown in Figure 1. H_2S is contacted with a regenerable sorbent in the first reactor (sulfider) at around 1,000°F. Zinc titanate-based sorbents appear to be the most promising regenerable sorbents among those that have been investigated. A two-fluidized-bed reactor system was chosen for the post-bed desulfurization as it offers many advantages including smaller and lower-cost equipment over fixed- and moving-bed systems.

**TABLE 1**

**TYPICAL PRODUCT GAS COMPOSITIONS OF A U-GAS GASIFIER**

(Air/Steam Gasification at 290 psi)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Moisture</th>
<th>Bituminous</th>
<th>Coal</th>
<th>Peat</th>
<th>Wood</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>%</td>
<td>5 %</td>
<td>25 %</td>
<td>20 %</td>
<td>20 %</td>
</tr>
<tr>
<td><strong>Gas Composition</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO, % by vol.</td>
<td>24.3</td>
<td>17.8</td>
<td>14.7</td>
<td>13.5</td>
<td></td>
</tr>
<tr>
<td>CO_2, % by vol.</td>
<td>5.2</td>
<td>8.3</td>
<td>10.9</td>
<td>12.9</td>
<td></td>
</tr>
<tr>
<td>CH_4, % by vol.</td>
<td>1.9</td>
<td>1.9</td>
<td>2.5</td>
<td>4.8</td>
<td></td>
</tr>
<tr>
<td>H_2, % by vol.</td>
<td>13.2</td>
<td>12.3</td>
<td>11.9</td>
<td>11.3</td>
<td></td>
</tr>
<tr>
<td>H_2O, % by vol.</td>
<td>5.3</td>
<td>10.9</td>
<td>13.5</td>
<td>17.1</td>
<td></td>
</tr>
<tr>
<td>N_2, % by vol.</td>
<td>49.9</td>
<td>48.3</td>
<td>46.5</td>
<td>40.2</td>
<td></td>
</tr>
<tr>
<td>LHV, BTU/scf</td>
<td>138</td>
<td>114</td>
<td>108</td>
<td>124</td>
<td></td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, JUNE 1992
Phenol Sales

DGC reports that a sale has been made to a New York company for a minimum of 10 million pounds of phenol annually from the Great Plains Synfuels Plant. The contract with Schenectady Chemicals provides for selling the minimum amount, but the company expects to be taking about half the plant's phenol-producing capacity.

About 35 million pounds of phenol can be produced from the phenosolvann streams at the synfuels plant. A phenol-recovery unit was installed at the plant in 1990. Phenol shipment under the 2-year contract began in February.

Schenectady will be using the phenol in making resins for various uses, including the making of tires and personal computer boards. DGC has been working to upgrade its phenol, removing neutral oil that has made marketing the byproduct difficult.

Another phenol sale has been made to an Oregon company and a trial shipment of the byproduct is in the works for another firm in Minnesota.

The sale will start at about 2 million pounds a year but that likely could double, said R. Hattenbach, sales manager for DGC. The phenol will be used in making plywood as well as a type of particle board for the housing industry.

GREAT PLAINS KEEPS GAS PRODUCTION UP, SELLS PHENOL

January production of natural gas was the second highest in the history of the Great Plains Synfuels Plant. The plant near Beulah, North Dakota averaged 161.5 million cubic feet per day.

K. Janssen, Dakota Gasification Company (DGC) vice president, said it was the second time that the plant produced above the 160-million mark for an entire month.

Janssen said problems with a compressor on one production train prevented the plant from surpassing the top daily rate of 163 million cubic feet. That daily record was set in March 1991.

Then in February, production increased still further making February the second highest production month in the plant's history. Natural gas delivery was recorded at 162.8 million cubic feet per day.

B. Graney, process operations manager, says the production was achieved by maximizing the onstream factor and performance of all equipment. Ash and sodium content of the coal was good in February, also contributing to the high rates.

STATUS OF CCT COAL CONVERSION PROJECTS UPDATED

The United States Department of Energy (DOE) published a Clean Coal Technology (CCT) Demonstration Program update in February summarizing the status of current projects. Those projects involving coal conversion are reviewed in the following.

Advanced Coal Conversion Process Demonstration

Rosebud SynCoal Partnership will use Western Energy Company's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals at the Colstrip, Montana demonstration site. The $69 million plant, funded 50 percent by DOE, will have a 300,000 ton per year capacity. Figure 1 shows the upgrading process.

Technology Description: Being demonstrated is an advanced thermal coal drying process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel. The coal is processed through two fluidized-bed reactors that remove loosely held water and then chemically bound water, car-
boxy groups, and volatile sulfur compounds. After drying, the coal is put through a deep-bed stratifier cleaning process to effect separation of the ash.

The technology enhances low-rank Western coal, with a moisture content of 25 to 55 percent, sulfur content of 0.5 to 1.5 percent, and heating value of 5,500 to 9,000 BTU per pound, by producing an upgraded coal product with a moisture content as low as 1 percent, sulfur content as low as 0.3 percent, and heating value up to 12,000 BTU per pound. Although the demonstration plant is one-tenth the size of a commercial facility, the process equipment is at commercial scale.

Project Status: Initial "turn-over" of equipment started in December 1991. Plant shakedown activities are under way with full operations scheduled for the second quarter of 1992.

Commercial Application: Western Energy’s advanced coal conversion process has the potential to enhance the use of low-rank Western subbituminous and lignite coals. Processed coal would be an ideal low-sulfur coal substitute at Midwestern plants that burn high-sulfur coals, because it will allow operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. The process, therefore, will be attractive to utilities because the upgraded fuel will be less costly to use than would the construction and use of flue gas desulfurization equipment. This will allow plants that would otherwise be closed to remain in operation.

Combustion Engineering IGCC Repowering Project

ABB Combustion Engineering, Inc. is demonstrating proprietary integrated gasification combined cycle (IGCC) technology at the City Water, Light and Power Lakeside Station in Springfield, Illinois. The $270.7 million demonstration plant, funded 48 percent by DOE, will convert 600 tons per day of coal into 65 megawatts of electricity. Figure 2 illustrates the IGCC process which includes a zinc ferrite sorbent and a limestone sorbent injection system to desulfurize hot gas.

Technology Description: The gasifier essentially consists of a bottom combustor section and a top reductor section. Coal is fed into both sections. A slag tap at the bottom of the combustor allows molten slag to flow into a water-filled quench tank.

The raw, low-BTU gas and char leave the gasifier at approximately 2,000°F and are reduced in temperature to about 1,000°F by various heat exchange surfaces and by water spray prior to gas cleanup. Char in the gas stream is captured by a high-efficiency cyclone, as well as by subsequent fine particulate removal systems, and recycled back to the gasifier.
A newly developed process is being used to remove sulfur from the hot gas: a moving bed of zinc ferrite sorbent. A limestone sorbent injection system provides in-bed desulfurization. Particulate emissions are removed from the coal-handling system and gas stream by a combination of cyclone separators and baghouses, and a high percentage of particulates is fed back to the gasifier for more complete reaction and ultimate removal with the slag.

The cleaned low-BTU gas is routed to a combined cycle system for electric power production. Approximately 40 megawatts are generated by a gas turbine. Extracted air from the gas turbine is used to meet the high-pressure air requirements of the gasifier and the zinc ferrite desulfurization system. Exhaust gases from the gas turbine are used to produce steam which is fed to a bottoming cycle to generate an additional 25 megawatts.

**Project Status:** The preliminary design package and plant cost estimates are complete. ABB Combustion Engineering held technical exchange discussions with the Japanese regarding the 200-ton per day entrained-flow gasification pilot plant in Japan, and obtained operational data for this plant for use in the CCT project.

**Commercial Application:** IGCC plants require 15 percent less land area than pulverized coal plants with flue gas desulfurization. IGCC technology also can be used in repowering, where a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added to replace the existing coal boiler. The remaining equipment is left in place, including the steam turbine and electrical generator.

**Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH) Process**

Air Products and Chemicals, Inc. will demonstrate the LPMEOH process to produce methanol from coal-derived synthesis gas at the Cool Water gasification facility in Daggett, California. In addition, the methanol produced will be tested for suitability as a low-NOx, low-NOx alternative fuel in boiler, turbine, and transportation applications. The $213.7 million project, funded 43 percent by DOE, will have a 150 ton per day methanol production capacity. Other project participants are Acurex Corporation, Texaco Syngas, Inc., and Dakota Gasification Company.

**Technology Description:** This project will demonstrate the LPMEOH process (Figure 3) to produce methanol from coal-derived synthesis gas on a commercial scale. The liquid phase not only supports the catalyst but functions as an efficient means to remove the heat of reaction away from the catalyst surface. This feature directly permits the use of a low ratio of hydrogen to carbon monoxide in the synthesis gas streams produced from coal gasification facilities as feed to the reactor without the need for shift conversion.

The LPMEOH process for the synthesis of methanol produces raw methanol of 97.5 percent purity. The process features feed gas flexibility, allowing the use of synthesis gas.
produced by any commercial coal gasification system to be used without shift conversion. Carbon monoxide conversion to methanol is 13 percent per reactor pass in a hydrogen-rich feed.

In addition to the original project objective, DOE will receive data on the use of a combined feedstock of coal and sewage sludge, which represents a new use for coal as a solution to a significant environmental problem and demonstration of combined IGCC/LPMEOH operation to produce power and byproducts in a load-following mode.

**Project Status:** The project is in negotiation. DOE approved a site change to the Cool Water Gasification Facility located at Daggett, California. Texaco Syngas, Inc., is negotiating to purchase the facility and plans to recommission it in 1993, using a combination of coal and municipal sewage sludge as fuel. A portion of the synthesis gas stream (up to 50 percent) will be diverted to a nominal 150 ton per day LPMEOH unit.

**Commercial Application:** LPMEOH technology can be used in both new and retrofit applications. Because of the variety of fuel products produced by the indirect liquefaction process, the technology can be used to supply fuels for a wide range of applications in the utility or industrial sector. Virtually any size boiler that uses coal, distillate, residual oil, or natural gas can use the fuels.

In an IGCC facility, LPMEOH technology is expected to reduce capital costs and improve electric power generating flexibility by storing energy in the form of methanol.

**Air-Blown/Integrated Gasification Combined-Cycle (IGCC) Project**

Clean Power Cogeneration Limited Partnership will determine the commercial potential of the air-blown fixed-bed IGCC technology. The $241.5 million demonstration in Lakeland, Polk County, Florida, funded 50 percent by DOE, has planned production of 120 megawatts of electricity. The IGCC process is illustrated in Figure 4. The plant will convert 1,270 tons of coal per day.

**Technology Description:** Coal is gasified in a pressurized, air-blown, fixed-bed gasifier. The low-BTU coal gas leaves the gasifier at approximately 1,000°F and goes to a hot gas cleanup system where the removal of sulfur compounds is accomplished in a moving bed of solid sorbent. The cleaned gas is delivered to a combustor, which is onboard the gas turbine frame. The gas turbine is integrated with the coal conversion system through pressurized air extraction, which is used as gasifier air supply. The steam generated in the heat recovery generator is used both for driving a conventional steam turbine generator set producing additional electricity and for gasifier blast. The project has the following subsystems: fixed-bed coal gasification, hot gas cleanup, a combus-
FIGURE 4
CLEAN POWER COGENERATION IGCC

SOURCE: DOE

mission turbine capable of using low-BTU coal gas, selective catalytic reduction for NOx control, a briquettor to utilize coal fines, and the balance of plant.

In the demonstration project, a nominal 1,270 tons per day of coal is converted into 120 megawatts. The base feed coal for the project is a high-sulfur Illinois Basin bituminous coal.

Project Status: The cooperative agreement with DOE was awarded in March 1991. On September 3, 1991, DOE approved a site change from the City of Tallahassee's Arvah B. Hopkins Station to Tampa Electric Company's Polk Power Station located in Polk County, Florida. Underway are preliminary design and engineering activities and studies for integration of the IGCC project into Tampa Electric's 260-megawatt first-phase generation expansion plan.

Commercial Application: IGCC technology can be used in repowering by replacing the existing coal-fired boiler with a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler. The remaining equipment is left in place, including the steam turbine and electrical generator.

Another application for IGCC is cogeneration under PURPA's Qualifying Facility provisions.

In its commercial configuration, IGCC technology is expected to result in plant efficiencies of up to 48 percent and result in an incremental power increase of 230 percent. SO2 emissions are expected to be reduced by 99 percent and NOx emissions by 95 percent.

ENCOAL Mild Coal Gasification Project

ENCOAL Corporation is using SGI International's liquids from coal process to process 1,000 tons per day of subbituminous coal feed. The $72.6 million demonstration plant is located near Gillette, Wyoming at Triton Coal Company's Buckskin Mine. The plant will produce two higher value fuel forms by mild gasification of low-sulfur subbituminous coal and provide sufficient products for potential end users to conduct burn tests. The ENCOAL gasification process is diagrammed in Figure 5.

Technology Description: The ENCOAL mild gasification process involves heating coal under carefully controlled conditions. Coal is fed into a rotary grate dryer where it is heated by a hot gas stream to reduce the moisture content of the coal. The solids from the dryer are conveyed to the pyrolyzer where the rate of heating of the solids and residence time are controlled to achieve desired properties of the fuel products. During processing in the pyrolyzer, all remaining free water is removed, and a chemical reaction occurs that results in the release of volatile gaseous material. Solids exiting the pyrolyzer are quenched, cooled, and transferred to a surge bin.

The gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled to condense
the liquid fuel products. Most of the gas from the condensation unit is recycled to the pyrolyzer. \( \text{NO}_x \) emissions are controlled by staged air injection.

The offgas from the dryer is treated in a wet venturi scrubber to remove particulates and a horizontal scrubber to remove \( \text{SO}_2 \), both using a sodium carbonate solution. The treated gas is vented to a stack, and the spent solution is discharged into a pond for evaporation.

**Project Status:** Design is complete and construction activities are ahead of schedule, with construction of all silos and the coal pyrolyzer complete, mine expansion tasks complete, all major equipment in place, and steel erection 80 percent complete.

**Commercial Application:** The liquid products from mild coal gasification can be used in place of No. 6 fuel oil. The solid product can be used in any scale industrial or utility boiler.

The potential benefits of this mild gasification technology in its commercial configuration are attributable to the increased heating value and lower sulfur content of the new solid fuel product (approximately 12,000 BTU per pound), compared to the low-rank coal feedstock and the production of low-sulfur liquid products requiring no hydrotreating. The product fuels are expected to be used economically in commercial boilers and furnaces and to significantly reduce sulfur emissions at industrial and utility facilities currently burning high-sulfur bituminous fuels or fuel oils.

**Cordero Coal Upgrading Demonstration Project**

Cordero Mining Company will produce a new fuel form using the Carbontec Syncoal process. The $343 million plant is planned for Gillette, Wyoming. The demonstration will upgrade high-moisture, low-sulfur, low-rank coals for use in powerplants designed to burn higher BTU coals, and as a lower sulfur fuel for future power generation and industrial facilities.

The plant will produce 250,000 tons per year of upgraded coal product. The process is shown in Figure 6. The project is being negotiated, and was selected by DOE in 1991 for a CCT Program award.

**Technology Description:** The Syncoal process converts high-moisture subbituminous coal into a high-BTU, low-moisture, low-sulfur product by using heat to drive off moisture and to stabilize the physical properties of the product. Hot oil and flue gas serve to heat the coal and to keep it in an inert atmosphere during coal processing. The hot oil provides a protective film which seals the surface to moisture as well as preventing surface degradation during handling. The flue gas drives off moisture and provides a relatively inert atmosphere to prevent oxidation of the coal during the treatment process and until the product is cooled to near ambient temperature.
Coal, which has already undergone two stages of crushing, is fed to a screening station where it is separated into three fractions. The coal is then fed into dryers where it is heated while a mixture of hot fuel oil is sprayed on the coal as it passes slowly through the heater. The coal is carried between two wire mesh conveyors, permitting the excess oil to drain freely to a sump at the bottom of the heater.

A portion of the smallest fraction is diverted to a feed bin, pulverized, and burned in the direct-fired tube heater. The balance is mixed with the partially processed coal leaving the dryers. The combined mixture is conveyed to a dryer/cooler, exposing it to hot flue gas which drives off more moisture. After cooling the finished product is then conveyed to a silo for storage.

Project Status: The project is in negotiation.

Commercial Applications: This process has the potential to enhance the use of low-rank Western subbituminous and lignite coals. It is expected that this upgraded coal product can be utilized by many Midwestern and Eastern utilities currently burning high-sulfur, high-rank, noncompliance coals to comply with the Clean Air Act Amendments of 1990 (CAAA) provisions. The processed coal would allow operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. Utilities are expected to find the upgraded fuel attractive because it will be less costly to use than would be the construction and use of flue gas desulfurization equipment. Moreover, plants that would otherwise be closed could remain in operation.

Pinon Pine IGCC Power Project

Sierra Pacific Power Company will demonstrate air-blown, fluidized-bed IGCC technology incorporating hot gas cleanup to evaluate a low-BTU gas combustion turbine. The long-term reliability, availability, maintainability and environmental performance of the technology will be demonstrated. The $340.7 million project will be funded 50 percent by DOE.

Technology Description: Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier through a lockhopper system (Figure 7). The bed is fluidized by the injection of air and steam into the combustion zone. Crushed limestone is added to capture a portion of the sulfur as well as to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits along with the coal ash in the form of agglomerated particles.

Hot, low-BTU coal gas leaving the gasifier passes through cyclones which return most of the entrained particulate matter to the gasifier. The gas, which leaves the gasifier at about 1,700°F, is cooled to 1,050°F before entering the hot gas cleanup system. During cleanup, virtually all of the remain-
ing particulates are removed by ceramic candle filters, and final traces of sulfur are removed in a fixed bed of zinc ferrite sorbent.

The hot, cleaned gas then enters the combustion turbine. The combustion turbine is coupled to a generator designed to produce 56 megawatts (gross). The heat from the combustion turbine’s exhaust gas is used to produce steam in a heat recovery steam generator. Superheated high-pressure steam drives a condensing steam turbine-generator designed to produce about 30 megawatts (gross).

In the demonstration project, a nominal 800 tons per day of coal is converted into 86 megawatts; support facilities for the plant require 6 megawatts for export to the grid. The project will be designed to run on Western subbituminous coal from Utah; operation with higher sulfur and lower rank coals also is being considered. The gasifier is being built at Sierra Pacific Power Company’s Tracy Station, located about 17 miles east of Reno, Nevada.

Project Status: The project is in negotiation.

Commercial Application: IGCC plants require 15 percent less land area than pulverized coal plants with flue gas desulfurization and exhibit substantially improved thermal efficiency and environmental performance. IGCC technology also can be used in repowering, where a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added to replace the existing coal-fired boiler. The remaining equipment is left in place, including the steam turbine and electrical generator.

Toms Creek IGCC Demonstration Project

TAMCO Power Partners (a partnership between Tampella Power Corporation and Coastal Power Production Company) will demonstrate IGCC technology using the Tampella U-GAS fluidized-bed gasification system. The $219.1 million project will be funded 50 percent by DOE, and has a planned capacity of 107 megawatts of electricity. The air-blown, fluidized-bed gasification combined cycle technology incorporating hot gas cleanup for generating electricity will be assessed for environmental and economic performance. Figure 8 shows the IGCC process flow diagram.

Technology Description: Coal is gasified in a pressurized, air-blown, fluidized-bed gasifier in the presence of a calcium-based sorbent. Approximately 90 percent sulfur removal is accomplished in the gasifier. Solids entrained in the gas are collected by cyclones in two stages. The low-BTU gas, which leaves the secondary cyclone at 1,800 to 1,900°F, is cooled to approximately 1,000°F before entering the post-gasifier desulfurization unit where zinc titinate is used to remove the bulk of the remaining sulfur in the gas. This is accomplished in two fluid beds. In the first bed the sulfur is absorbed by the zinc titinate and the zinc sorbate is regenerated in the second bed. In the final hot gas cleaning step, a ceramic candle filter removes particulates. The gas in then sent to the gas turbine combustor.
Hot exhaust gases from the combustion turbine are directed to a heat recovery steam generator. The steam generated in the heat recovery generator is used both for driving a conventional steam turbine generator set producing additional electricity and for gasifier blast.

A nominal 430 tons per day of bituminous coal will be converted into 55 megawatts of electricity by the coal-gas-fired gas turbine. An additional gas turbine fired with natural gas and a heat recovery steam generator will be co-located at the demonstration site. The two gas turbines will be coupled with a single steam turbine to generate a total of 107 megawatts of electricity and approximately 20,000 pounds per hour of steam for export to an adjacent coal preparation facility. The electric power will be sold to a utility.

The planned site for construction of the new IGCC powerplant is Coeburn, Virginia at the Toms Creek Mine owned by ANR Coal, a subsidiary of Costal Power Production Company.

Project Status: The cooperative agreement with DOE is still under negotiation.

Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

ThermoChem, Inc. will demonstrate advanced combustion using pulse combustor technology from Manufacturing and Technology Conversion International (MTCI). The $37.3 million project, funded 50 percent by DOE, is expected to produce 161 million BTU per hour of medium-BTU fuel gas plus 40,000 pounds per hour of export steam. The current plant design is illustrated in Figure 9.

Technology Description: The MTCI fluidized-bed gasifier incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-BTU fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by MTCI’s multiple resonance tube pulse combustor technology with the resonance tubes comprising the heat exchanger immersed in the fluidized-bed reactor. Heat transfer is 3 to 5 times greater than other indirectly heated gasifier concepts, allowing the heat transfer surface to be minimized.

The product gas has a heating value of about 161 million BTU per hour with a cold gas efficiency of 53 percent or more. The demonstration plant’s overall efficiency is expected to be 72 percent or more. In major commercial applications, char combustion and heat recovery operations can be included to enhance overall plant efficiency.

Aqueous sodium hydroxide scrubbing is used to control SO₂ emissions. Scrubber overflow is utilized in the paper mill.

The demonstration facility will be built at Weyerhauser Paper Company’s Containerboard Division mill located in Springfield, Oregon. The fuel gas and byproduct steam...
produced in the demonstration facility will be consumed by the mill. Subbituminous coal from Gillette, Wyoming will be used as the feedstock.

**Project Status:** The cooperative agreement with DOE for project funding is still under negotiation.

**Commercial Applications:** The MTCI pulse combustion technology has a wide range of potential applications, including utility steam and power generation. This project is demonstrating the use of pulse combustion for steam gasification of coal in a major paper company's industrial containerboard mill to produce medium-BTU fuel gas and byproduct steam. The new technology will replace hog-fuel boilers currently in use.

There are more than 350 pulp mills, which produce 64 million tons per year of pulp, and 600 paper mills in the United States. The processing of pulp results in the production of about 88 million tons of byproduct black liquor. The current practice of using black liquor recovery boilers to produce steam and electricity is inefficient. Replacing these boilers with MTCI gasifiers would significantly improve the conversion efficiency. The estimated market for MTCI gasifiers in this application alone is 28 units annually.

**Wabash River Coal Gasification Repowering Project**

Destec Energy, Inc. and PSI Energy, Inc. form the Wabash River Coal Gasification Repowering Project Joint Venture.

The project will demonstrate IGCC technology using Destec Energy's two-stage, entrained-flow gasification system. The $591.9 million project, funded 41 percent by DOE, will produce 265 megawatts net of electricity. Figure 10 is a diagram of the coal gasification repowering project.

**Technology Description:** Coal is ground, slurried with water, and gasified in a pressurized, two-stage (entrained-flow slagging first-stage and non-slagging second-stage), oxygen-blown, entrained-flow gasifier. The product gas is then cooled through heat exchangers and passed through a conventional cold gas cleanup system which removes particulates, ammonia, and sulfur. The clean, medium-BTU gas is then reheated and burned in an advanced 192-megawatt gas turbine. Hot exhaust from the gas turbine is passed through a heat recovery steam generator to produce high-pressure steam. High-pressure steam is also produced from the gasification plant and then superheated in the heat recovery steam generator. The combined high-pressure steam flow is supplied to an existing 110-megawatt steam turbine.

The process has the following subsystems: a coal-grinding and slurry system, an entrained-flow coal gasifier, a cold gas cleanup system which produces a marketable sulfur byproduct, a combustion turbine capable of using coal-derived fuel gas, a heat recovery steam generator, and a repowered steam turbine.

One of six units at PSI Energy's Wabash River Generating Station, located in West Terre Haute, Indiana, is being
repowered. The demonstration unit will be designed to generate 265 megawatts net using 2,544 tons per day of high-sulfur, Illinois Basin bituminous coal. Upon completion, the project will represent the largest single-train IGCC plant in operation in the United States.

**Project Status:** The cooperative agreement with DOE for project funding is still under negotiation.

**Commercial Application:** In recent years, IGCC has become a rapidly emerging alternative for new electric generating plants. In addition to the previously mentioned benefits of IGCC technology, the performance potential of IGCC technology in its commercial configuration is characterized by its compactness—high process efficiency reduces space requirements per unit of energy generated. Also, modular construction lends itself to economic increments of capacity additions to match load growth.

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SYNTHETIC FUELS REPORT, JUNE 1992
ILLINOIS COAL WASTE TO BE TESTED AS GASIFIER FEEDSTOCK

The Illinois State Geological Survey is testing the use of Illinois coal slurries for gasifiers. The project is funded by the United States Department of Energy and is monitored by the Center for Research on Sulfur in Coal. The slurry, produced from coal waste streams, will be evaluated for use in gasifiers by Destec Energy, operator of the country's largest slurry-fed gasifier.

The slurry will also be evaluated for pipeline transportability by Williams Technology. A slurry transported by pipeline offers coal mines technical and economic advantages over transporting dewatered coal particles by rail.

The slurry ultimately will be used as feedstock in coal gasification plants. Compared to coal-fired boiler technology which has 33 percent efficiency, the gasification combined cycle provides a 40 percent efficiency. The advantages of this for Illinois include new markets for the state's coal mines, more efficient power generators and an environmentally sound power plant technology.

COMPANIES REPORT PROGRESS IN GAS TURBINES FOR GASIFICATION APPLICATIONS

The "1992 International Gas Turbine and Aeroengine Technology Report" from the International Gas Turbine Institute of the American Society of Mechanical Engineers presents reports from several companies updating their progress in using gas turbines for gasification applications. A summary of these reports is presented below.

Westinghouse Electric Corporation

Westinghouse continues to make significant progress in combustion turbine technology. For more than 30 years, the company has worked on advanced programs utilizing coal in combustion turbines, and has supported more than 50 individual research and development projects.

Currently, the company is working with the United States Department of Energy on the development of combustion turbines to be used in coal-fired combined cycles. Concepts under investigation which have commercial potential include the use of combustion turbines in first- and second-generation pressurized fluidized beds, and in direct and indirect coal-fired systems. Plant heat rates for these systems can be as low as 6,500 BTU per kilowatt-hour.

The company's experience with syngas started more than 13 years ago. By 1987, two 501DS combustion turbines were converted to run on 239 BTU per standard cubic foot syngas at The Dow Chemical Company plant in Plaquemine, Louisiana. The Dow Chemical installation is the world's largest integrated coal gasification combined cycle plant.

Westinghouse is also working with Northern States Power on the commercialization of a direct coal-fired combined cycle concept incorporating a pressurized slagging combustor.

Shell Oil Company

The Shell Coal Gasification Process (SCGP) is an oxygen-blown, entrained-flow coal gasification process utilizing a proprietary dry coal feeding system. SCGP produces a clean, medium BTU gas with a heating value of approximately 300 BTU per standard cubic foot. This type of gas has been shown to be an excellent fuel for advanced design gas turbines in combined cycle units.

The first commercial project to employ SCGP is being built in The Netherlands by Demkolec B.V., a subsidiary of the Dutch Utility Generating Board. When operation begins in 1993, it will be the largest coal gasification combined cycle powerplant in the world.

The Demkolec Project will be a nominal 250 megawatt integrated coal gasification combined cycle (IGCC) powerplant. The coal gasification facility will employ a single 2,000 ton per day gasifier. Typically, 99 percent carbon conversion and a coal-to-gas efficiency of over 79.5 percent will be achieved. The gas produced by coal gasification will fuel a single 150 megawatt V94.2 combustion turbine manufactured by Siemens/KWU. The SCGP plant will be fully integrated with the combined cycle plant, including the boiler feed water and steam systems. The plant is expected to operate on Drayton, an Australian coal. The IGCC heat rate will be approximately 8,240 BTU per kilowatt-hour.

General Electric Company

In October 1991, the completion of successful no-load, full-speed testing of the new MS9001F gas turbine at the company's gas turbine manufacturing plant in Greenville, South Carolina was announced. The 9F, the world's most powerful gas turbine, originally was rated at 212 megawatts but recently was uprated to 216 megawatts, based on the test results. The 9F is a scaled-up version of the 7F turbine.

To date, there are commitments for 53 "F" class gas turbines worldwide, including 40 7Fs and 13 9Fs. The first 9F application will be at Electricite de France's Gennevilliers site near
Paris. Another early installation will be in a combined cycle powerplant proposed for construction at Didcot, Oxfordshire, United Kingdom. National Power PLC plans a two-module power station, with each module including two MS9001F gas turbines, two heat recovery steam generators and one steam turbine providing an output of 680 megawatts with a thermal efficiency of more than 54 percent.

The first MS7001F gas turbine, in operation since June 1990 at Virginia Power’s Chesterfield 7 station, continues to surpass industry standards for high reliability, availability and maintainability. The Chesterfield 7F unit has recorded an average reliability of 99 percent, with a starting reliability of 100 percent for 155 starts. At more than 50 percent efficiency, the Chesterfield 7 combined cycle unit is the most thermally efficient large powerplant in the United States.

Based on the operating experience at Chesterfield as well as extensive factory testing, the output rating of the MS7001F was increased from 150 to 159 megawatts.

The company has announced the completion of a 25-month powerplant optimization study for the construction of the world’s largest combined cycle powerplant. In August, a contract was signed with Tokyo Electric Power Company for the design of the power generation facilities of a 2,800 megawatt plant to be built at a site in the Tokyo area. GE will provide eight MS9001F gas turbines for the plant’s single-shaft STAG generating units, each using a newly designed steam turbine and generator.

GE has announced two integrated gasification combined cycle improvements which further demonstrate the efficiency and economic viability of the most environmentally friendly clean coal technology available.

Based on the results of the first advanced gas turbines in utility service, the company announced new ratings for its “F” technology gas turbines for use with moistured coal gas. A recent study showed that an MS7001F gas turbine fueled by coal gas can generate 191 megawatts of electric power versus 159 megawatts for those fired with natural gas.

The second significant IGCC improvement was the completion of the first 100-hour run on a hot gas cleanup pilot plant located at GE’s Corporate Research and Development Center. The pilot plant was designed and constructed by GE Environmental Systems and GE Corporate Research and Development Center with support from the United States Department of Energy. The plant demonstrated sulfur removal of more than 98 percent from the hot gases which exited the gasifier.

###
GOVERNMENT

ILLINOIS CCT FUNDING EARMARKED FOR TWO GASIFICATION PROJECTS

Illinois is developing clean coal technologies to support the state's coal industry in meeting new federal power plant emission standards. The state has an abundant supply of high-sulfur coal, and is focusing efforts on developing clean-burning and efficient technologies to make use of it.

More than $1.1 billion has been spent or is allocated for the Clean Coal Technology (CCT) Programs in Illinois. Each demonstration project selected must meet five criteria:

- The project must use high-sulfur Illinois coal as the primary feedstock.
- All emissions from the project facility must meet federal and state environmental regulations.
- The projects must use innovative technology, most of which are commercial scale demonstrations.
- The project must be located in Illinois.
- The project must offer significant economic benefits to Illinois.

Some of the projects currently being planned for demonstration, being demonstrated, or commercially operated in Illinois include two gasification projects, a gas burning/sorbent injection technology for power generation, a fluidized bed combustor, and a flue gas sulfur scrubber.

The first coal gasification project will be located in the Illinois Coal Development Park. Construction for the $18 million mild coal gasification demonstration project will begin in 1993. The technology uses lower temperatures and pressures than current gasification processes. The facility will have a 24 ton per day capacity for converting coal to clean-burning solid fuel. Liquids produced as byproducts will be used for plastics. Gasoline and fuel gas from the conversion process will fire the demonstration plant. The facility will recover sulfur from a variety of coal fuels.

The second coal gasification project, at the City Water, Light & Power Lakeside Station, will use combined cycle power generation. Construction for the facility is expected to begin in 1994. With this technology the coal is converted to gas, and then the gas is cleaned and burned in a combined cycle generator.

Other CCT projects include a desulfurization system at the Abbott plant in Champaign-Urbana. The Chiyoda Thoroughbred scrubber reduces sulfur dioxide emissions by 90 percent. The plant is operated by the University of Illinois and has proved to be very economical, saving an estimated $3 million by using coal rather than natural gas for heating and cooling.

The Archer Daniels Midland Company uses a fluidized bed combustion technology to capture more than 90 percent of sulfur dioxide emissions. The facility has a 1.25 million ton per year capacity for burning high-sulfur coal.

The Illinois Power Company's Hennepin Station and the City Water, Light and Power Springfield Station both are testing gas reburning/sorbent injection technology. The Hennepin Station demonstration shows that 77 percent of nitrogen oxides and 62 percent of sulfur dioxide emissions are removed.

The Illinois CCT demonstration projects are funded by the federal government, the state and by industry.

DOE ISSUES DRAFT SOLICITATION FOR CCT ROUND V

The United States Department of Energy (DOE), emphasizing the need for demonstrating technologies which will enable utilities to meet the strict air-emissions standards in the post-2000 era, has issued the draft solicitation for proposals for participation in the fifth round of the Clean Coal Technology (CCT) Demonstration Program.

The draft solicitation, called a Program Opportunity Notice (PON), was mailed to more than 3,000 individuals and firms who had previously expressed interest in the CCT Program.

The draft PON was released to solicit public input in developing the final solicitation of projects. The draft was developed following two public meetings held last year in Louisville, Kentucky and Cheyenne, Wyoming. Congressional guidance and public comments received over the past several months were also taken into account in drafting the solicitation, says DOE.

In the solicitation, DOE is proposing to broaden the focus of the CCT Program to include a wider range of eligible technologies.

The emphasis of Round V will be to demonstrate highly-efficient, ultra-clean technologies. Utilities will be required to use these technologies in the post-2000 era when a permanent cap on sulfur dioxide emissions goes into effect.

SYNTHETIC FUELS REPORT, JUNE 1992
Although the PON emphasizes super-clean, high-efficiency systems, all coal-use technologies will be eligible for consideration in Round V. However, DOE says that proposals for projects that directly duplicate previous efforts in the CCT Program or seek to demonstrate commercial techniques are not encouraged.

Previous rounds of the CCT Program have emphasized technologies that will assist existing powerplants in meeting the nearer-term emission targets established by the Clean Air Act Amendments of 1990. The Clean Air Act set up two significant deadlines for emission reductions: January 1, 1995, and January 1, 2000. Currently, 42 projects are participating through previous rounds of the CCT Program. Fifteen of those projects are now completed or in operation.

DOE is also seeking to allow government cost-sharing for certain activities outside the demonstration itself—such as pilot plant tests to help verify design and select project materials. Such efforts would help to attract newer, more innovative technologies, says DOE. Under the proposed guidelines, DOE’s cost share of these activities would be limited to 10 percent of its overall contribution to the project and no government funds could be used to build new facilities.

The draft solicitation also contains detailed information on the criteria that will be used in evaluating the proposed projects. Reviewers will judge the proposed demonstration projects based upon the readiness of the technology, the adequacy and relevance of the demonstration, environmental, health and safety issues, and the management of the project as well as the technology’s potential for commercialization.

The draft notes that technical evaluation guidelines would be weighted three times as important as the cost-financing criteria. The proposed guidelines say that DOE will consider "the extent to which the proposed technology enables the continued and increased use of coal for conversion to useful energy forms in new or existing facilities by improving control of noxious emissions associated with its use," including SO₂, oxides of nitrogen and air toxics. Also counted would be the extent to which the control levels exceed those of technologies already commercialized in the United States, as well as the degree to which the proposed technologies would limit solid and liquid waste.

Provisions requiring the repayment of the government’s contribution to each project after its actual successful commercialization are also contained in the draft proposal. These provisions are identical to the requirements used in the third and fourth rounds of competition. The limit on DOE funding for any one project is 50 percent of the total project cost.

J.G. Randolph, Assistant Secretary for Fossil Energy, said, "By focusing on the super-clean, high-efficiency systems, the Clean Coal Program is taking steps to ensure that coal remains a viable energy alternative well into the next century."

DOE’s deadline for issuing the final solicitation is July 6, 1992. Project selection for Round V is scheduled for May 1993.

In recent months, the DOE has been criticized for not making the most of the clean coal funds. The General Accounting Office complained that at least three projects would have been commercialized without federal help, and that the department sank $21.2 million into projects that were later terminated.

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SYNTHETIC FUELS REPORT, JUNE 1992  

4-17
GE SEES FAVORABLE MARKET OUTLOOK FOR IGCC

The market outlook for integrated gasification combined cycle (IGCC) technology was assessed in a paper by P.R. MacGregor, et al., of General Electric Company. Their paper was presented at the Power-Gen '91 conference held in Tampa, Florida last December.

The integration of coal gasification technology with the combined cycle plant, as demonstrated by the Cool Water IGCC project, yields a power generation technology that will compete with conventional pulverized coal steam plants in the coming years. The short lead time and low capital cost of simple cycle gas turbines make these units suitable for peaking applications. Should oil/natural gas fuel prices increase, existing simple cycle plants can be converted to efficient combined cycle plants with the addition of a steam cycle. If the need arises, a coal gasifier can then be integrated with the system to permit use of coal as the fuel for an IGCC plant. As a result, an IGCC plant can be developed progressively, thereby conserving capital investment in contrast to competing baseload technologies. This flexibility, say the authors, provides significant economic incentives to plant owners.

A conventional IGCC plant is shown in Figure 1. A sulfur scrubber removes sulfur from the fuel gas and processes the sulfur to a salable product. The gas cooler produces steam which is utilized by the steam turbine. Because limestone is not injected for sulfur removal in an IGCC, the solid waste from a gasifier is non-leachable and is a salable byproduct. The particulate scrubber system removes particulates, trace alkali metals, and fuel bound nitrogen converted to ammonia in the gasifier.

There are many alternatives to the cycle described above including air blown gasifiers, integrated air systems and hot gas cleanup systems. Air blown gasifiers produce a lower BTU content fuel with half the heating value of an oxygen blown gasifier. The gasification system and cleanup for an air blown system is twice the size of an oxygen blown system.

Hot gas cleanup (HGCU) systems remove sulfur from the coal gas at higher temperatures and deliver a higher temperature cleaned fuel gas to the gas turbine. HGCU is currently under development. This simplifies the system configuration and reduces the cost by eliminating or reducing the gas cooling equipment as well as improving efficiency.

System Reliability

IGCC plant reliability and availability can be equal to that of a combined cycle plant because the IGCC gas turbine plant is equipped with dual-fuel capability to burn backup fuel. In the event that the coal gas fuel is not available, the plant can easily switch over to the backup fuel and continue to supply reliable power to the power system.

Generation system reliability determines the required generation reserve margins of the power system. The total reserve margin requirements of a generation system are comprised of two key elements: load demand uncertainty and generating unit unreliability. If the power system utilizes gas turbine technology in contrast to steam plant technology, a lower reserve margin requirement results.

GE says that power system reliability is of great importance in the power generation industry. High-reliability gas turbine technology leads to high system reliability and the ability to reduce overall generation system reserve margin requirements. Lower reserve margin requirements lead to decreased needs for future capacity, which can yield large capital and economic savings.

Environmental Emissions

With the passage of the 1990 Clean Air Act Amendments, environmental considerations have become a key factor in the decision process for selecting generation technologies. Because of limits on future total SO₂ emissions, new plants can be added only by offsetting their new emissions by decreased...
emissions in other existing plants. Because offsets and SO\textsubscript{x} controls are expensive, plant technologies having low emissions have economic and plant siting advantages.

IGCC technology has environmental loading characteristics similar to combined cycle plants. Low SO\textsubscript{x} characteristics are achieved because of the high efficiency sulfur removal of the fuel stream prior to combustion. Low NO\textsubscript{x} is achieved by using the same low NO\textsubscript{x} technology of current gas turbines.

Economic and Performance Characteristics

Capital costs of new generation equipment is another key factor driving the economic selection of generation technology. The average cost of recently completed conventional coal steam plants constructed in the United States is approximately $1,400 per kilowatt. Natural gas combined cycle powerplants are estimated to cost between $580 and $620 per kilowatt.

Because IGCC is an evolving technology, it may be expected to proceed through a technology learning curve phenomenon, say the authors. IGCC technology has evolved from a 35 megawatt plant developed by British Gas-Lurgi in 1975 through several actual and proposed projects as illustrated in Table 1. The Cool Water project was a technical demonstration project and consequently had a high capital cost. The same size gasifier used on the 120 megawatt Cool Water project, today, would generate enough fuel gas for a 260 megawatt plant.

Current IGCC technology may use an Integrated Air Separation Unit (IASU) using the gas turbine compressor to improve costs and reduce auxiliary power requirements. Advanced IGCC may use HGCU to improve plant cost and efficiency. This is achieved by removing the sulfur compounds at 1,000 to 1,100°F using a zinc ferrite or zinc titanate sorbent material. HGCU is now ready for technical demonstration.

The IGCC learning trend can also be viewed from a technology component perspective as illustrated in Figure 2. Figure 3 (page 4-20) presents the plant capital costs by major equipment function. Current conventional IGCC technology has an investment cost of about $1,500 per kilowatt.

MacGregor, et al., note that the net plant heat rate of IGCC plants has also been on a learning trend from the 11,300 BTU per kilowatt-hour value of the Cool Water plant to Shell IGCC studies of specific utility sites averaging 9,100 BTU per kilowatt-hour. Inclusion of IASU technology can improve efficiencies to the 8,200 BTU per kilowatt-hour level and HGCU has the potential for further reduction.

Economic Comparisons

Table 2 (page 4-21) gives a summary of the economic data and the operating characteristics of the three key conven-

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**TABLE 1**

<table>
<thead>
<tr>
<th>Project</th>
<th>Operation Year</th>
<th>MW Size</th>
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<tbody>
<tr>
<td>British Gas-Lurgi</td>
<td>1975</td>
<td>35</td>
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<tr>
<td>British Gas-Lurgi</td>
<td>1981</td>
<td>50</td>
</tr>
<tr>
<td>Texaco-Coolwater</td>
<td>1984</td>
<td>120</td>
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<tr>
<td>Dow-Plaquemine</td>
<td>1987</td>
<td>160</td>
</tr>
<tr>
<td>Shell Oil-Houston</td>
<td>1987</td>
<td>40</td>
</tr>
<tr>
<td>Shell-Netherlands</td>
<td>1993</td>
<td>250</td>
</tr>
<tr>
<td>Penuesas, P.R.</td>
<td>1995</td>
<td>260</td>
</tr>
<tr>
<td>HTW/Lurgi-Germany</td>
<td>1995</td>
<td>300</td>
</tr>
<tr>
<td>Dow-PS Indiana</td>
<td>1995</td>
<td>230</td>
</tr>
<tr>
<td>C.E.-Springfield, IL</td>
<td>1995</td>
<td>60</td>
</tr>
<tr>
<td>Texaco-Fretown, MA</td>
<td>1996</td>
<td>520</td>
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<tr>
<td>Texaco-Delaware</td>
<td>1996</td>
<td>250</td>
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<tr>
<td>TECO</td>
<td>1996</td>
<td>250</td>
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<tr>
<td>CAC, Canada-Shell</td>
<td>1996</td>
<td>250</td>
</tr>
<tr>
<td>TAMCO</td>
<td>1996</td>
<td>120</td>
</tr>
<tr>
<td>Sierra Pacific</td>
<td>1996</td>
<td>90</td>
</tr>
<tr>
<td>Prenflow-Germany</td>
<td>1997</td>
<td>160</td>
</tr>
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</table>
Hydro, solar, wind, refuse, conservation and other renewables play a contributing role, but the key technologies for the 1990s and beyond will be gas turbine and coal technologies, says GE.

Using a simulation model for evaluating the generation mix of new equipment orders, a forecast of the market opportunity of various technologies was made for each North-American Electric Reliability Council region. Approximately 68 gigawatts of coal fueled technology (IGCC plus pulverized coal steam plant plus alternative technologies) is estimated to be ordered through the year 2000. This is approximately one-third of the total generating unit orders that are estimated to occur during this time period.

J.R. Siegel of Bechtel Power Corporation discussed the outlook for power from coal industries at the Alternate Energy 1992 Conference of the Council for Alternate Fuels held in Charleston, South Carolina at the end of April. Given modest and sustained economic growth, Bechtel sees substantial new power generation capacity requirements over the next 10 years.

At a 3.0 percent per year average growth rate (assuming a 20 percent reserve margin), additional electric generating capacity of 180 gigawatts must be installed and operating by 2001 (Figure 1). At the extremes of 2.0 and 3.5 percent per year, the range of requirements that must be operating by the year 2001 is 120 to 240 gigawatts.

Considering lead-times, about 255 gigawatts must be ordered over the next 10 years. Because of the compounding nature of requirements growing over an extended period of time, over one-half of all projected new orders (150 gigawatts) occur in the last 5 years of the forecast.

In Bechtel's base case forecast, gas is the fuel of choice in the near term, but coal economics prevail near the end of the period. During the first 5 years, the forecast sees new requirements to be two-thirds gas or dual fuel and one-third coal or solid fuel. In the second 5 years, one-half gas or dual fuel and one-half coal or solid fuel. Alternative energy sources and renewables can be expected to add an important, albeit small, amount of capacity. In arriving at these fuel market shares, the following real fuel price increases were assumed:

- Oil: 4 percent per year
- Natural gas: 4.5 percent per year
- Coal: 1.0 percent per year

The 1992 starting points are $20 per barrel of oil, $2.50 per million BTU delivered utility gas, and $1.50 per million BTU delivered utility coal.

The technology mix also varies during the 10-year forecast period. The technologies that Bechtel envisions include pulverized coal, fluidized bed combustion, gas turbine combined
## TABLE 2

**ECONOMIC AND PERFORMANCE DATA**

(All Costs in 1991 $)

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Simple Cycle</th>
<th>Combined Cycle</th>
<th>Steam Cycle</th>
<th>IGCC Current</th>
<th>IGCC Advanced</th>
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<tbody>
<tr>
<td></td>
<td>Nat. Gas</td>
<td>Nat. Gas</td>
<td>Coal</td>
<td>Coal</td>
<td>Coal</td>
</tr>
<tr>
<td>Fuel Cost ($/MBTU U.S. avg.)</td>
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<td>2.65</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>Heat Rate (BTU/kWh-HHV)</td>
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<td>7135</td>
<td>9700</td>
<td>8200</td>
<td>7800</td>
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<tr>
<td>Plant Cost ($/kW)</td>
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<td>600</td>
<td>1400</td>
<td>1500</td>
<td>1300</td>
</tr>
<tr>
<td>O&amp;M Cost</td>
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<tr>
<td>Fixed ($/kW/yr)</td>
<td>1.0</td>
<td>5.0</td>
<td>14.0</td>
<td>16.0</td>
<td>16.0</td>
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<td>Variable ($/mWh)</td>
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<td>1.9</td>
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</tr>
<tr>
<td>Reliability (%:1-FOF)</td>
<td>98.5</td>
<td>96.5</td>
<td>92.8</td>
<td>96.0</td>
<td>96.0</td>
</tr>
<tr>
<td>Availability %</td>
<td>95.0</td>
<td>91.0</td>
<td>84.0</td>
<td>90.0</td>
<td>90.0</td>
</tr>
<tr>
<td>Discount Rate (%/yr)</td>
<td>11.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed Charge Rate (%/yr)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel Cost Escalation (%/yr)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>DRI</td>
</tr>
<tr>
<td>Plant Cost Escalation (%/yr)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>4.5</td>
</tr>
<tr>
<td>O&amp;M Cost Escalation (%/yr)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>4.5</td>
</tr>
</tbody>
</table>


**cycle, gas turbine simple cycle, and integrated coal gasification combined cycle. Also to be constructed are waste-to-energy units, and the repowering and upgrading of existing facilities.**

### Challenges Facing the Industry

Since the 1973 oil embargo, the use of coal by utilities has almost doubled. Today 57 percent of United States domestically produced electric energy comes from coal. Bechtel Power believes the nation must continue coal’s vital role in a reliable, cost-effective and environmentally responsive manner through the widespread commercialization of clean coal technologies.

To facilitate the full commercialization of clean coal technologies, Bechtel Power supports the continuation of the United States Department of Energy Clean Coal Technology Demonstration Program as well as legislation to carry out research and development on advanced coal-based technologies.

### Industry Structure

According to Siegel many utilities have already recognized that today’s competitive environment is placing increasing demands on their business and strategic initiatives. To meet their obligations to produce power and also satisfy shareholder interests, utilities are considering not only new generation, but also least cost planning and purchased power. When utility generation construction is selected, utilities are using innovative procurement practices including partnering, target price contracts, and lump-sum turnkey contracts in order to achieve their objectives.

The development of Non-Utility Generation (NUG) is also proliferating in response to legislation, state policies, after-the-fact prudency reviews, and utilities who prefer to procure new supply through power purchase agreements. About 100 entities are currently involved in independent or cogeneration power projects totaling 98 gigawatts. Of this total, about 38 gigawatts are in operation and 60 gigawatts are actively under development. Early on, most of the NUG projects involved qualifying facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA). Increasingly, however, independent power projects not qualifying under PURPA are being proposed. Market-based pricing for electricity wholesalers (as opposed to cost-of-service regulation) is also evolving through case-by-case Federal Energy Regulatory Commission rulings. Since 1986, utilities in over 20 states have been involved in numerous solicitations for power purchase agreements.
FIGURE 1

AT 3 PERCENT GROWTH, NEW SUPPLY NEEDS APPROXIMATE 180 GW

AVERAGE ANNUAL GROWTH (1982-1991)
3.3%

2.5% GROWTH

3.0% GROWTH

SUPPLY NEEDS
140-180 GWe

COMMITTED AVAILABLE CAPACITY

*COMMITTED AVAILABLE CAPACITY FIGURE IS NET OF 20% REQUIRED RESERVE MARGIN

SOURCE: SIEGEL
CHEMICAL COPRODUCTION WITH IGCC PROMISING IF GAS PRICES INCREASE

Houston Lighting & Power Company is conducting a two-site-specific study for the coproduction of electric power, industrial-grade methanol, agricultural grade ammonia and industrial and agricultural grade urea in a coal gasification-based Integrated Coproduction Energy Facility (IEF). This study is being performed for the Electric Power Research Institute (EPRI).

EPRI wants to determine if the coproduction of products in conjunction with the production of electricity can in fact reduce the levelized cost of electricity by incorporating the revenues of the coproduct. The economic viability of coproduction must be carefully evaluated because true profitability from the total facility may not be realized until natural gas prices recover from their depressed position. All of the coproducts being considered are currently derived from natural gas and therefore their market price is highly dependent on natural gas price.

One of the major objectives of the study is to design a standard IGCC plant that is integrated in both electricity production and coproduct production. Other objectives are to identify and to quantify the coproducts that are economically feasible to coproduce with electricity, the long-term value of those coproducts, and the life-of-plant levelized cost of electricity based upon coproduct production.

The two sites are located in Texas. Site A, adjacent to the Shell refinery in Deer Park, is located in a strategic location to maximize the economical transfer of coproducts to the market via the Houston Ship Channel traffic pathways. The fuel for this site is a blend of Illinois No. 6 and petroleum coke. The coproduct is methanol. Site B is in central Texas and makes use of mine mouth lignite. This site has as its coproducts ammonia and urea, which are in demand for agricultural uses and chemical feedstock. This site makes use of both close availability of fuel and of coproduct markets.

The reference case IGCC baseload plant configuration for Sites A and B consists of two gasifiers, two advanced gas turbines, two heat recovery steam generators (HRSG), and one steam turbine. The reference case IGCC, operated in the dispatched mode, consists of two gasifiers, four conventional gas turbines, four HRSG's and two steam turbines.

The factors which were used to evaluate potential coproducts were:
- Overall costs of producing the coproduct
- Market demand
- Market value and long-term price stability

A total of eight cases were developed which cover the broad spectrum of operations including:
- Baseload to cycling duty operations
- Full electricity production to full coproduct production operations
- Use of both MS7001E and MS7001F gas turbines to evaluate each case for optimal load following flexibility and fuel efficiency

Methanol as a Selected Coproduct

Methanol is an important feedstock and fuel additive. According to the authors of a paper presented at the 10th EPRI Coal Gasification Power Plants Conference, demand growth for methanol in the chemical area is forecast in the 3.0 to 4.0 percent range annually; the surge in demand as a feedstock for methyl tertiary butyl ether (MTBE) is high. The impact of the Clean Air Act on MTBE demand is expected to be in the 30 percent range in 1992.

Methanol is the coproduct of choice, especially for a Gulf Coast site, because of its versatility as both a fuel and chemical. Methanol can be sold into various markets taking advantage of the price leveling effect of a diverse market. By producing a basic chemical rather than a downstream product, the capital required for the plant is reduced and the market risk associated with commodity chemicals is spread out and effectively lowered. Industrial grade methanol (99.85 percent methanol) was chosen because of its wider market.

Conclusions

Preliminary results for two of the eight cases studied are shown in Table 1.

Case 2, the reference dispatch case with four GE Frame 7E gas turbines and two Shell gasifiers, yielded a combined net output of 502 megawatts, with a net plant heat rate of 8,887 BTU per kilowatt-hour on the Illinois No. 6 coal/petroleum coke blend. The total plant cost amounted to $762.2 million, resulting in an installed cost of $1,518 per kilowatt.

Case 4, the dispatch liquid methanol coproduction case, yielded an output of 450 megawatts and a 2,300 ton per day methanol plant producing 102 million gallons of methanol annually when the power production runs at an annual capacity factor of 50 percent. The cost of the methanol plant
TABLE 1
ECONOMIC COMPARISON WITH COPRODUCTION

Case 2:
(2) Shell Gasifiers, (4) GE 7E Gas Turbines CC
Illinois No. 6/Pet Coke Blend, Houston Ship Channel Location
Heat Rate = 8,887 BTU/kWh
Net Power Output = 502 MW
Capital Cost, 1991 Dollars, Million
Gasification $382.6
Power Block Plus General Facilities 379.6
Total $762.2
$1,518 per kW

Case 4:
(2) Shell Gasifiers, (4) GE 7E Gas Turbines CC
Illinois No. 6/Pet Coke Blend, Houston Ship Channel Location
Co-Production, 2300 TPD Liquid Phase Methanol
1991 Selling Price $0.50/Gallon
Net Power Output = 450 MW
Capital Cost, 1991 Dollars
Gasification $382.6
Power Block Plus General Facilities 379.6
Methanol Plant 127.1
Total $889.3

amounted to approximately 17 percent of the IGCC plant cost or $127.1 million.

Figure 1 (next page) shows the cost of electricity with coproduction of liquid phase methanol under low, middle, and high gas scenarios showing a marginal reduction in the cost of electricity at the middle and high gas price for a coproduction plant operating at a 50 percent (electrical output) annual capacity.

NEW APPROACHES SUGGESTED FOR HIGH-VALUE CHEMICALS FROM COAL

Researchers at Pennsylvania State University have been exploring possible ways to develop high-value chemicals from coals and coal liquids. C. Song and H. Schobert of the Department of Materials Science and Engineering authored a paper on research needs and opportunities in this area. Their paper was presented at the American Chemical Society's Fuel Chemistry Division symposium held in San Francisco, California in April.

The authors discussed major problems facing the industrial utilization of coals such as carbonization, combustion and liquefaction, the importance of developing coal chemicals, new strategies for developing useful and competitive coal chemicals, possible methods for developing several specialty chemicals, and future research areas related to coal structural chemistry.

According to the paper, it will become necessary to produce synthetic liquids from coals for transportation fuels and for chemicals. Despite enormous strides in coal liquefaction research, however, coal-derived liquid fuels are still not cost competitive with petroleum. Liquid fuels from coal must also meet with the 1990 Clean Air Act Amendment requirements. For this reason, the transportation fuels will be hydrogen-rich, highly aliphatic fuels. The production of such fuels from coal-derived syncrudes will be considerably more expensive than those from petroleum crudes.

Increased environmental concern about the greenhouse effect will result in significant environmental pressure on the use of coals as boiler fuels. Abundant supplies of cheap and clean natural gas will compete with coal-fired power generation. Synthetic fuels from coals do not seem likely to be competitive with petroleum for transportation fuels until 2010 or beyond, they say.
As a hydrocarbon source, coal can also be used as feedstock for chemicals and materials, in addition to its use as a fuel. By developing critical chemicals and substances for advanced materials, coal chemical research could contribute significantly to high-technology development. The commercial and military importance of advanced polymer materials such as liquid crystalline polymers (LCP) resides in their unique properties. Development of high-value chemicals from coal liquids could not only significantly increase the economic viability of coal liquefaction, but also make coal liquids more competitive with petroleum because coal contains many chemicals which are not found in petroleum.

Chemicals from Coals

In regard to aromatic specialty chemicals, the liquids from advanced coal liquefaction may be theoretically more attractive as feedstocks for aromatic chemicals as compared to Fischer-Tropsch synthesis. This approach leads to aromatics, phenols, and heterocyclic compounds as chemicals. The disadvantage of chemicals from liquefaction is the presence of many, but not necessarily desirable, alkyl substituents on the ring systems. Two approaches can be taken to overcome this problem. The first is to use a simple liquefaction method followed by catalytic dealkylation of the coal liquids. The second approach is catalytic or thermal liquefaction at lower temperature to derive the aromatic compounds, followed by thermal dealkylation, producing relatively simple aromatics. These approaches may become viable with the large-volume demands for aromatic chemicals, and can be economically competitive if improved separation methods emerge.

Another alternative is to introduce a reagent into the coal to cleave only a certain well-defined set of bonds. Low-rank coals offer promise for production of phenol and catechol type chemicals as well as BTX (benzene, toluene, xylenes) and naphthalene. According to the authors, a careful oxidation should be able to produce large yields of benzene carboxylic acids. If long chain aliphatic units exist, clipping the ends of the aliphatic chains may allow useful materials based on aliphatic carbon to be recovered.

Aromatic Polymer Materials

Engineering plastics are relatively higher in cost but have superior mechanical properties and greater durability. Polyimide-type heat-resistant polymers, as well as carbon fibers, were developed initially for the aerospace industry,
but they now have found wide commercial applications. Polyimides have experienced extremely rapid developments in recent years, the major emphasis being on engineering applications.

The liquid crystalline polymers (LCPs) containing naphthalene or biphenyl rings are capable of replacing metals and ceramics in many applications. Moldings of these rigid, rod-like, heat-resistant engineering polymers may be used in place of metals and ceramics for electronics, aerospace, and transportation applications.

Advanced Carbon Materials from Coals and Coal Liquids

It is now well known that various useful carbon materials and composite materials can be made from coals, coal tars, coal liquids from liquefaction, and petroleum. Currently, coal tar pitch and bituminous coals (for making coke) are the major feedstocks of coal-based carbon materials. Coals ranging from low-rank coals to anthracites, and heavy liquids from coal liquefaction and tars from low temperature pyrolysis may be used for carbon materials in the future.

According to the paper, the large-volume uses of coals for carbon materials can be stimulated significantly by the development of molecular sieving carbons (MSC) for gas separation and the adsorbent carbons for purifying water and air, and medical and environmental applications. The application of MSC for air separation by the PSA method is now commercially viable.

Large-volume uses of coal liquids, including those from carbonization and liquefaction, may depend mainly on the development of technologies for producing general-purpose and mesophase-based carbon fibers, including activated carbon fibers for environmental protection uses, graphite electrodes, and mesophase microbeads-based materials. Coal tar pitch-based carbon fibers are still in the development stage. Recently, commercialization of coal tar pitch carbon fibers has been announced by Mitsubishi Chemical and Osaka Gas.

Coal-derived materials have higher nitrogen and oxygen contents than petroleum feedstocks. The application of catalytic hydroprocessing for structural modification and heteroatom removal of coal-derived carbonization feedstocks may become increasingly important for making mesophase-based carbon materials such as carbon fibers and graphite electrodes. Moderate hydrogenation and hydrodenitrogenation (HDN) of pitch feedstocks using large-pore hydrotreating catalysts can improve the carbonization process. More importantly, HDN of the feedstocks may significantly improve the properties of the coal-based mesophase carbon materials upon graphitization.

Conclusions

The authors conclude that "the potential exists, and the future may show handsome dividends from relatively modest investments in research on organic coal structures, reactivity, catalytic conversions, new pretreatments, novel reactions, supercritical extraction for the conversion processes such as direct coal-to-chemicals and coal liquid-to-chemicals tests coupled with advanced liquefaction methods. While it may seem to be beyond the scope of coal science, the conversion of the coal aromatic chemicals to specialty chemicals such as 2,6-dialkynaphthalene is also an important part, which determines the potential of coal chemicals as monomers for polymer materials."
TECHNOLOGY

INTEGRATION OF IGCC WITH COMPRESSED AIR ENERGY STORAGE SHOWS PROMISE

The Electric Power Research Institute (EPRI) and Energy Storage and Power Consultants, Inc. (ES&PC) have determined that the coal gasification system (CGS) with compressed air energy storage (CAES) results in a marginal improvement in plant economics over a conventional integrated coal gasification combined cycle (IGCC) plant. However, a major consideration for practical and reliable operation is that the CGS/CAES system could provide continuous operation of the gasifier and turboexpander train. In addition, the evaporated-recuperated or Humid Air Turbine (HAT) cycle, which utilizes a humidifier to saturate the motive air stream, can be thermodynamically advantageous due to the incremental power produced by the moisture in the air and the gainful heat exchange.

M. Nakhamkin, et al., of ES&PC and A. Cohn, et al., of EPRI presented their work on CGS/CAES at the International Power Generation Conference in San Diego, California in October. The authors developed a hybrid concept which combines features of the HAT concept with the integrated CGS/CAES concept. This potentially attractive concept, utilizing an Integrated coal Gasification system (IG) and Compressed Air Storage with Humidifier, is designated as IG/CASH.

The use of air saturation in IG/CASH concepts was thought to have potential to be more effective both thermodynamically and economically than its use in the HAT cycle combined with the conventional IGCC system due to the following:

- CAES plants are associated with relatively high cycle pressures compared to standard gas turbines. As a result of these high cycle pressures, the optimized compressor train usually has two or three intercoolers for increased efficiency and an aftercooler to match the discharge air temperature to that of the underground storage. Heat of compression, which is conventionally wasted, can potentially be stored as hot water and the hot water later utilized to saturate the high pressure compressed air flow from the underground storage reservoir.

- Low temperature heat available in the IG/CASH cycle has a greater potential of being utilized than in the HAT cycle combined with the conventional IGCC cycle because the compressed air stream to be preheated and saturated is initially at a low temperature (approximately 100°F) coming from the underground storage.

- The high cycle pressure also permits the use of cycles more efficient than simple cycle reheat gas turbines.

- The recuperator, an essential component of a HAT cycle, is part of the conventional CAES plant design.

- Previous studies of CGS/CAES systems indicated that CGS capacities per kilowatt of net power could be reduced by up to 30 percent as compared to the IGCC plant. It was believed that air saturation could reduce required CGS capacity even more.

In order to conduct a comprehensive analysis, multiple IG/CASH concepts and alternatives within these concepts were initially identified. Figure 1 presents a simplified schematic of the overall IG/CASH plant.

The ultimate selection criteria for the most economical alternative is based on the plant specific capital cost of dollars per kilowatt, and the cost of electricity to the customer load in dollars per kilowatt-hour.

Results of Analyses

A comparative thermodynamic analysis showed that the gasifier type is a major factor affecting IG/CASH plant economics. A modified Total Quench (TQ) gasifier provided the best economics, better than the standard TQ.
gasifier, which in turn was better than the Radiant plus Convec-
tive (R+C) type gasifier. The second major feature af-
fecting the overall plant economics is the type of tur-
bomachinery train. Concepts which utilize the "advanced"
turbomachinery were more efficient than those with the
"standard" train.

Table 1 includes a summary of the overall plant performance
and economics for the best IG/CASH concepts. Both the
"standard" and "advanced" turbomachinery trains have been
included for the IG/CASH concepts.

It appears that the use of air saturation in IG/CASH plants
might reduce capital costs of coal gasification based
powerplants used in intermediate load generation by $300 to
$400 per kilowatt. Furthermore, heat rates might also be
reduced. When reduced fuel costs are combined with reduc-
tions in capital costs, costs of electricity from such systems
might be reduced by almost $0.015 per kilowatt-hour, a
major reduction. The major cause of the reduction in
electricity costs is the 50 percent reduction in the required
gasification capacity.

IG/CASH concepts provide a method to operate the CGS
and turbomachinery in a continuous mode, improving the
operations and potentially the life expectancy of both com-
ponents. IG/CASH plants can also be used as a load
management tool because they consume off-peak energy and
can therefore increase the capacity factor and average ef-
iciency of base loaded plants.

From Table 1, it appears also that the use of the heat of com-
pression in hot water storage has only a marginal economic
benefit which does not justify its increased complexity.
Therefore, the preferred alternatives for both standard and
advanced turbomachinery concepts are those which provide

---

**TABLE 1**

**COMPARISON OF BEST AS/CGS/CAES CONCEPTS WITH CONVENTIONAL IGCC UNITS**

<table>
<thead>
<tr>
<th>Concept Description</th>
<th>AS/CGS/CAES Standard Turbomachinery Train</th>
<th>AS/CGS/CAES Advanced Turbomachinery Train</th>
<th>Conventional IGCC With 7FCC</th>
</tr>
</thead>
<tbody>
<tr>
<td>CGS/Turbomachinery train</td>
<td>Cyclic Mod. TQ</td>
<td>Cyclic Mod. TQ</td>
<td>Cyclic Mod. TQ</td>
</tr>
<tr>
<td>Coal gasification system type</td>
<td>4</td>
<td>4</td>
<td>1</td>
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<tr>
<td>Number of turboexpander trains</td>
<td>2</td>
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<td>2</td>
</tr>
<tr>
<td>Number of gasification trains</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Hot water storage use</td>
<td>8</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Air compressed to storage, hrs/day</td>
<td>8</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Gasification &amp; turbomachinery operated, hrs/day</td>
<td>16</td>
<td>16</td>
<td>16</td>
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<tr>
<td>Power supplied to customer load, hrs/day</td>
<td>16</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>Performance Results</td>
<td></td>
<td></td>
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<tr>
<td>Compressor capacity, kW</td>
<td>643,214</td>
<td>641,796</td>
<td>302,584</td>
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<tr>
<td>Off-site power required at CAES/CGS plant, kW</td>
<td>655,774</td>
<td>651,956</td>
<td>307,994</td>
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<tr>
<td>CAES/CGS plant net capacity, kW</td>
<td>513,045</td>
<td>538,266</td>
<td>394,069</td>
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<tr>
<td>Gasification capacity in lbs/hr of coal per net kW</td>
<td>0.423</td>
<td>0.423</td>
<td>0.444</td>
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<tr>
<td>Overall heat rate, BTU/kWh</td>
<td>10,645</td>
<td>10,328</td>
<td>8,587</td>
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<tr>
<td>Plant Economics</td>
<td></td>
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<tr>
<td>Estimated plant cost, $/kW</td>
<td>1,038</td>
<td>1,027</td>
<td>952</td>
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<tr>
<td>Estimated costs of electricity:</td>
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<tr>
<td>Cost of coal, mills/kWh</td>
<td>16.18</td>
<td>15.67</td>
<td>13.05</td>
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<td>Plant capital charge, mills/kWh</td>
<td>27.75</td>
<td>27.48</td>
<td>25.45</td>
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<tr>
<td>Maintenance costs, mills/kWh</td>
<td>7.78</td>
<td>7.70</td>
<td>7.14</td>
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<tr>
<td>Total costs of electricity, mills/kWh</td>
<td>51.72</td>
<td>50.85</td>
<td>45.64</td>
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</table>

SYNTHETIC FUELS REPORT, JUNE 1992
continuous CGS and turbomachinery operation, and do not require hot water storage.

###

**SILICON CARBIDE CANDLE FILTERS MAKING PROGRESS IN HOT GAS CLEANUP**

The Electric Power Research Institute (EPRI) recently summarized the status of using silicon carbide candle filters to remove particulates upstream of a gas turbine to maximize overall combined cycle plant efficiency. Hot gas filtration has been demonstrated for both Pressurized Fluidized Bed Combustion (PFBC) and coal gasification.

There are a number of manufacturers that can make the silicon carbide (SiC) candle, but the leader in the world at the moment is the Schumacher Company in Germany. The basic material is a fairly course granular ceramic structure sintered either with clay or proprietary binders. The filtering surface is then coated with a microporous layer to achieve surface rather than in-depth filtration. For the SiC candles, the filtering surface is on the outside of the elements. A permanent thin dust-cake build-up keeps the pores from blinding. Cleaning is achieved by reverse blowing a short pulse of high pressure gas across the filter. Stable forward pressure drop is typically achieved in a few thousand pulse cleaning cycles.

The primary problems in the design of a practical filter system include making a durable ceramic to metal connection, packaging the elements for large systems and distributing pulses to a large number of elements without using pulse tubes. A number of projects in the United States, Europe and Japan have been addressing these issues for both gasification and PFBC applications. EPRI is involved in some way with most of these projects around the world. The largest operating unit to date (120 candles) is the EPRI hot gas filter on British Coal's PFBC pilot plant in Grimethorpe, England. This was first operated in a 1987 campaign and achieved over 800 hours on Schumacher filters. Additional 1,500 generating hours are planned to be completed by early 1992 to further prove the chemical and thermal stability of these candles. Recent tests, however, have revealed a cleanability problem with ash from the particular English coal and limestone mix being used. The greatest success to date has been achieved by Deutsche Babcock which has successfully operated two parallel filter systems using Schumacher candles for over 2,000 hours at their 15-megawatt PFBC facility.

Another significant PFBC project will come on line this year. At ABB Carbon in Sweden, a 48 element Schumacher filter system will be tested on a 10 megawatt PFBC component test facility. In the United States, one-seventh of the flow from American Electric Power's (AEP) 80 megawatt Tidd PFBC plant will be diverted to a Westinghouse filter using 384 Schumacher candles arranged in nine clusters (see Figure 1). This will be the first demonstration of a commercial design approach. However, extensive laboratory testing at Westinghouse for AEP has revealed that the Tidd ash is also difficult to clean. Testing continues to resolve this problem.

Gasification filter projects are also moving ahead at a rapid pace. Rheinbraun in Germany has successfully tested a 90 candle Schumacher system at their 25 bar plant in Wesseling. They are using this experience to scale up to a 600 candle unit for their 10 bar gasifier at Berrenrath which will be followed in 1996 by a 2,500 candle system at the Kobra plant.

![Figure 1: Candle-Based Advanced Particle Filter](image)

## AARDELITE PROCESS MAKES AGGREGATE FROM GASIFIER ASH

A process for the conversion of coal fly ash into artificial gravel was developed by Aardelite. The process uses the pozolanic properties of pulverized coal fly ash or other residues. According to the company, the process is easily adaptable to the processing of various types of residues from coal combustion, as well as that of other solid residues. A. Kodde and G. Teekman from Aardelite Holding B.V. dis-
cussed the utilization of coal gasification byproducts at the Power-Gen '91 conference held in Tampa, Florida in December.

**Background**

Aardelite, an environmental engineering company located in The Netherlands, developed a process for the conversion of pulverized coal fly ash into a light weight aggregate. The process has proven its technical and economic viability, using coal fly ash as a feedstock, among others in a plant in Crystal River, Florida which has been operated by PMI, a Florida Progress subsidiary, for over 3 years. In a pilot plant located in Nunspeet, The Netherlands, a variety of materials has been successfully used as feedstock in the process, and economically attractive re-utilization schemes were developed for many of these materials.

**Process Description**

In the process (Figure 1) fly ash is mixed with a binder, usually lime, and water in a mixer. The green mix is then fed to a pelleting machine. Agglomeration to round aggregate takes place on the pelleting machine. After leaving the pelleting machine a certain amount of dry fly ash is added to the green pellet as an embedding material. The green pellets are conveyed to the curing section, where they are held at a temperature of approximately 190°F. In 12 to 16 hours the properties of the fly ash, in combination with the lime and the presence of steam, ensure that a pozzolanic reaction takes place, binding the particles and producing a stone-hard aggregate.

The authors found that the function of the embedding material, among others, is to ensure that during curing the as-yet unhardened green pellets are separated and do not collapse under the pressure resulting from stacking the pellets in the curing silos. The use of embedding materials was found to be a key element in the ability of this technology to process large quantities of material in a small footprint plant.

Cured material is continuously extracted from the bottom of the curing silos. The embedding material is separated from the aggregate and returned to the process to serve as a feedstock. Oversize material is crushed to size. The aggregate is fractionated into the required size ranges and can be used in a number of applications both for road construction and the manufacture of concrete and concrete products.

**Applications of the Process**

The process, initially developed for the processing of pulverized coal fly ash, has been used successfully to process a number of other byproducts, such as:

- Fluidized bed boiler ash
- Fine fractions of bottom ash
- Spray dry residue
- Municipal solid waste bottom ash and fly ash
Using Residue from Coal Gasification

The Shell coal gasification process produces two types of residue. Most of the mineral matter entering with the coal melts and flows down the wall of the gasifier. The molten slag then flows through a slag tap in the bottom, is quenched in water and removed via lockhoppers. Slag from the Shell Coal Gasification Process is dark and glassy in appearance.

Fly slag is removed from the raw syngas in the dry solids removal section and recycled to the gasifier. Depending on plant configuration and mode of operation, a smaller amount of fly slag, 5 percent of the total amount of slag in the Demkolec plant, will not be recycled and becomes available as a byproduct.

Demkolec, the owner and operator of the 250 megawatt plant under construction in The Netherlands, and Shell, as a supplier of gasification technology, requested Aardelite to perform testing to verify the suitability of coal gasification slag and coal gasification fly slag as a feedstock in the Aardelite process for the production of lightweight aggregates.

The "as received" particle size distribution of slag does not enable pelletizing it. However, after adding 25 percent fines pelletizing was no problem. Adding 25 percent slag to a mixture of regular fly ash and binder drastically improved the size distribution of the particles in the mix and resulted in a noticeable improvement in pellet strength.

Aggregate with good strength could be made from both slag and fly slag. The strength of aggregate made with slag was substantially higher than that made with fly slag.

Further testing is being carried out to determine full compliance with the relevant specifications for aggregate for concrete and asphalt concrete. Comparing the properties of aggregate made with IGCC slag and fly slag with that of other man-made aggregates, Aardelite says it is clear that, using both slag and fly slag from the Shell Coal Gasification Process, artificial aggregate can be made which has excellent properties and can be used as a replacement for natural aggregate in concrete products and asphalt concrete for road construction.

###

RANKING SYSTEM DEVELOPED FOR COAL GASIFICATION PROCESSES

W.H. Tuppeny of T & M Associates, Inc., et al., revealed a methodology for selecting coal gasification processes at the Eighth Annual International Pittsburgh Coal Conference held in Pittsburgh, Pennsylvania in October 1991. The processes are evaluated in relation to feedstock characteristics and end user needs for each situation.

Organizations investing in large capital projects have evolved economic models that incorporate financial parameters in order to provide optimum financial returns. However, experience indicates that often, complex, coal-based projects fall short of forecasted performance as the result of unrealistic technology and equipment performance projections which are factored into economic models.

The decision methodology designed by T & M Associates is structured to screen process options against user needs and feedstocks. This provides choices and direction which maximize the potential for achieving end user objectives.

The technique for projecting performance is based on modularizing system components and projecting the performance of these modules using team expertise and available performance data. System performance projections can then be made within certain ranges of probability. The methods employed by the authors have been used by individuals and organizations to select least cost/low risk options best suited for specific needs.

Methodology

The procedure for evaluating and ranking technology-based processes is a series of systematic steps involving interactions between the user and an expert team. The methodology is diagrammed in Figure 1.

The key elements to be identified include clearly defined and agreed upon objectives including: timing, end product needs, technology preferences, feedstock, and constraints. Such information forms the basis for the screening criteria, technical and economic criteria which will be used in the evaluation.

Results

Examples of generic database screens which reflect the general thinking of several potential users are shown as follows:

For the power industry:

- The supplier of the process must be active in gasification technology development.
- A pilot plant must be available to enable feedstock testing and gas quality analysis.
- The base line experience of the supplier must be no less than 150 tons per day on bituminous coal in order to ensure an acceptable scaling range.
For the chemical industry, the screens are the same as for the power industry with the addition that the supplier must be capable of providing a pressurized process above the nominal level, i.e., greater than 5 bars, in order to ensure reasonable gas production economics.

The processes that passed both sets of T & M Associates' screening criteria are:
- Texaco
- GSP
- Prenflo
- Lurgi-Fixed Bed
- CRIEPI
- Dow
- BGL
- HTW
- GKT
- Shell

Republic of South Africa Gasification Study

The methodology described was utilized in a study performed for various Republic of South Africa (RSA) Government agencies and potential gasification users. The objectives of the study were to review coal gasification technologies on a worldwide basis and provide the sponsors with information that would assist them in formulating plans to maximize the use of their indigenous knowledge, technical resources, and diverse coal resources.

One of the key goals of the study was to establish the relative expected performance of gasifiers using RSA feedstocks. A sample of results for the low-range steam coal feedstock classification is provided in Figure 2.
Results such as these permit prospective users to narrow choices of options which can offer the best opportunity for achieving desired technical and performance objectives. Such evaluations are only a starting point for the prospective user to engage in refining site specific selections, pricing and commercial terms which are offered by prospective suppliers.

NEW SOURCES FOR COAL TAR CHEMICALS MAY BE NEEDED

C.L. Irwin from West Virginia University, et al., assessed the current worldwide supply and uses of coal tar at the Eighth Annual International Pittsburgh Coal Conference held in Pittsburgh, Pennsylvania in October.

Background

Coal tar is derived as a secondary product from byproduct coking operations; thus its supply is directly linked to the demand for blast furnace coke. The demand for blast furnace coke is dependent upon the overall demand for steel, and the extent to which this demand is met by recycling scrap steel in electric arc furnaces. Another factor affecting the demand for blast furnace coke is the extent to which new iron and steel making processes using minimal amounts of coke are implemented. Environmental regulations on operating byproduct coke ovens will also impact the production of coal tar. The supply of coal tar is further dependent upon the relative amount of coke which is made in nonrecovery coke ovens. Currently, this is less than 4 percent of total coke production, but may increase in the future.

Coal tar is produced, traded, and processed by multinational companies; therefore, any attempt to assess the supplies of coal tar must be done on a worldwide basis. For example, Germany and Japan expect to import coal tar as their domestic production declines. Other countries such as Brazil, China, Korea, and Russia may have excess coal tar for export to other tar refining countries.

Current Coal Tar Products

Coal tar products include chemical oils, creosote, and coal tar pitch. The chemical oils may be further processed into naphthalene, phthalic anhydride, phenol, solvents, and a variety of industrial chemicals and materials. An important use of coal tar pitch with moderate to high quinoline insolubles is for binder pitches to make electrodes. Through secondary coking, coal tar pitch can be further processed into low coefficient of thermal expansion (CTE) anisotropic needle coke, anode coke, or high CTE isotopic coke.

New Coal Tar Products

According to the authors, there is a potential for new uses of coal tar in those products which are now produced from petroleum coke and pitches. This is particularly true in the United States where, for economic and availability reasons, petroleum coke is widely used as filler coke in aluminum anodes and graphite electrodes, and for isotropic coke in specialty graphites. Petroleum pitch is used as impregnating pitch in electrode manufacture, and as a precursor for mesophase pitch in making carbon fibers.

Alternative Feedstocks for Coke Oven Coal Products

There are several developments which would diminish coal tar supply over the next 10 to 15 years: the impacts of environmental regulations, the cost of rebuilding or replacing coking operations, recycling of scrap steel in electric arc furnaces, and to a lesser extent, the emergence of nonrecovery coke ovens and new ironmaking processes which use coal or natural gas directly.

According to the authors, in order to preserve the use of coal as a feedstock for the many products which are derived from coal tar, it is also possible to expand other coal technologies such as mild gasification, liquefaction processes, solvent extraction, bioconversion, etc., which either directly or indirectly yield chemicals or pitch from coal. The feasibility of alternative sources for tar, pitches, and chemicals depends upon the economics of the process.
Conventional byproduct coking of coal yields about 70 percent coke plus gas and chemicals. With market prices for gas and chemicals, a coke value of $110 per ton and a pitch value of $300 per ton, the revenue per ton of coal fed to a conventional coke oven is approximately $100. An alternative coal-to-pitch process would require a pitch yield of about 33 percent to generate the same revenue per ton of feed coal. To provide sufficient incentive, pitch yields in the 60 to 70 percent range would be required to generate commercial interest.

There is no immediate shortage of coal tar on a worldwide basis. However, to have an economical, secure supply of coal tar Irwin says the following two goals should be considered:

- Develop new carbon forms and products from coal tar, and new applications for coal tar chemicals and pitches.
- Develop alternative processes to conventional coke ovens as a source of feedstocks for producing coal derived pitches and chemicals.

These goals will support the United States in decreasing the national dependence on imported energy resources, and in expanding the nonfuel uses of coal.

####
The Institute of Gas Technology (IGT) has reached an agreement with the Shanghai STTCO International Trading Company and the Shanghai Coking and Chemical Company General (SCCP) of the People's Republic of China for the use of IGT's U-GAS coal gasification process as part of SCCP's Trigen Project. The Trigen Project, which is located at the SCCP plant in Wujin, is so named because it generates three products from coal: town gas, chemicals, and electricity.

Under the terms of the agreement, a series of U-GAS gasifiers will be designed, constructed, and brought on-line in phases at the Wujin site. Each unit will be able to gasify 130 tons of coal per day. The U-GAS process will be used to produce a low-BTU fuel gas that will replace coke oven gas in SCCP's coking plant. The coke oven gas will then be used for town gas.

According to IGT president B. S. Lee, "IGT is very excited about the Trigen Project and the use of our U-GAS process as a part of it. Trigen represents the first commercial introduction in China of IGT's advanced fluidized-bed gasification process."

IGT developed the U-GAS process with funding support from the United States Department of Energy (DOE), the American Gas Association, and the Gas Research Institute. During a decade of development, IGT refined the technology through an extensive multidisciplinary program. Over 10,000 hours of operation were logged in more than 120 tests at a pilot plant in Chicago. A wide variety of domestic and foreign coals were tested.

The highly efficient U-GAS process can operate with air, oxygen, or enriched air to produce low- or medium-BTU gas. The process uses the ash agglomeration technique, which allows high-ash material to be discharged without the high temperatures necessary for slagging. Fines leaving the gasifier are recycled and gasified, further enhancing efficiency.

The current agreement is the latest in a series of actions taken by IGT to commercialize the U-GAS process worldwide. In September 1989, IGT entered into a licensing agreement with the Finnish company Tampella Ltd., whose primary interest is to use the U-GAS process for generating electricity in integrated gasification combine cycle (IGCC) plants. Last year, DOE selected Tampella to build a U-GAS-based IGCC demonstration facility known as the Toms Creek IGCC Demonstration Project.

China has selected Texaco's coal gasification technology for a fertilizer plant to be located near the City of Xian. This is the second Texaco gasification facility to be licensed in China this year.

The Weihe Chemical Fertilizer Plant, under license from Texaco Development Corporation, will gasify coal to produce ammonia, an important component of fertilizer. When completed in 1996, the plant will produce 300,000 tons per year of ammonia, which will in turn be used to produce 520,000 tons per year of urea fertilizer.

Located in the largely agricultural Shaanxi Province, the plant will significantly increase domestic fertilizer production, a major goal for China in order to help reduce its long-time reliance on imports of fertilizer, and to improve its balance of trade. The plant will gasify 1,500 tons per day of coal. (A comparably sized plant in the United States would cost in excess of $350 million).

"By utilizing the Texaco gasification process, the new Weihe Chemical Fertilizer Plant will make use of coal, China's most abundant energy resource, to produce fertilizer in an environmentally superior manner," said D.C. Crlkelair, vice president of Texaco Inc. and head of Texaco's Alternate Energy and Resources Department.

The Texaco gasification process is a versatile technology that can utilize coal, heavy oil, waste gas, petroleum coke and other hydrocarbon feedstocks to produce a clean-burning synthesis gas for a variety of industrial products, fuel and electricity in an environmentally sound way.

Texaco recently announced that a technology licensing agreement has been finalized for a gasification plant in the City of Shanghai, China. The Shanghai Coking and Chemical Plant will gasify 1,100 tons of coal per day to produce town gas and chemicals.

The Weihe and Shanghai plants will make the eighth Texaco-licensed gasification plant operating in China, producing fuel and chemical products for a variety of purposes. The first Texaco gasification plant in China was licensed in 1978. Since then, four gasification plants have been constructed to use heavy oil to produce ammonia and other chemicals. In addition, two other coal gasification projects are under construction: the gasifier at the Lunan Fertilizer Plant (Shandong Province) will produce ammonia for fertilizer production; and the Shougang Plant (Beijing) will produce a fuel gas for industrial use.
CARBOGAS PROJECT IN SPAIN WILL BE INTERNATIONAL EFFORT

The Carbogas Project will demonstrate integrated gasification combined cycle (IGCC) technology at a site in Puertollano, Spain. The project comes within the framework of the Thermie Program of the European Community and will be undertaken by a consortium of utility companies in Spain, France, Portugal and Italy. Joining these countries in supplying products for the project’s construction will be Germany, England, and Belgium.

The plant will have facilities for the storage and preparation of a wide variety of coals which will be tested during the 3-year demonstration period. There are plans to test coals from England, Spain, France, the United States, China, Australia, Colombia, Germany, Poland, South Africa and a mixture of Puertollano coal with petroleum coke.

An overview of the Carbogas Project was presented at the Power-Gen '91 conference held in Tampa, Florida last December by U. Sendin, et al. Sendin is a representative of Empresa Nacional de Electricidad in Spain, one of the project’s leading participants.

Other members of the consortium from Spain are IBERDROLA, Hidroelectric del Cantabrico and Sevillana. Also in the consortium are Electricite de France, Electricidad de Portugal, and ENEL, the Italian electricity company. Other utilities are expected to join the project.

The project goal is to demonstrate the feasibility of a 300-megawatt net IGCC powerplant with a wide range of bituminous coals. Puertollano is located about 200 kilometers south of Madrid, close to the open mine of ENCASUR.

Technical Description

The plant configuration is single-train throughout. Using oxygen and steam, about 100 tons of coal per hour will be gasified. The required oxygen, approximately 90 tons per hour, will be produced in a single-train air separation unit. The resulting coal gas will be dedusted, desulfurized and saturated in a single-train configuration and then combusted in a single combustion turbine.

The gasifier technology and the gas turbine manufacturer have not been selected for this project. Either an entrained flow gasifier or a fixed bed gasifier will be chosen.

Environmental Considerations

According to Sendin, even if they were not mandatory due to environmental legislation, the following recommendations are worthwhile from a purely economic point of view:

- It is advantageous to build a plant with high efficiency and thus low CO₂ emissions, because the resulting lower coal consumption reduces power generation costs.
- It is advantageous to produce only slag, because this will avoid the high disposal costs involved with carbonaceous waste material (fly ash).
- It is advantageous to desulfurize the coal gas almost completely, because this enables the sensible heat in the combustion turbine exhaust gas to be utilized down to low temperature levels.
- It is advantageous to saturate the coal gas with steam for the purpose of NOₓ control, because such saturation makes it possible to achieve a heat pump effect, by means of which low level heat is boosted to a higher level.

The substantially lower CO₂ emissions in comparison with conventional processes is a direct consequence of the higher thermal efficiency of the new technology. Using coal gasification, at least 12.5 percent less coal is required to generate a specific amount of electricity, compared to conventional technology with an efficiency of 40 percent. Compared to a plant efficiency of 35 percent, coal savings of more than 25 percent can be realized. This means that a reduction of CO₂ emissions by 25 percent by the year 2005 could be achieved if conventional powerplants were to be replaced by IGCC powerplants, says Sendin.

Main Target Dates

The project schedule has the following main target dates:

- Consortium formation - April 1992
- Supplier selection - March 1992
- Civil work start - November 1992
- Combined cycle (end of construction) - December 1994
- Gasification island (end of construction) - December 1995
- Commissioning with natural gas - January 1995
- Commissioning with coal gas - January 1996
- Demonstration period - 1996-1998

###
COAL PRICE REFORM CAUSES DIFFICULTY FOR SHANGHAI GAS WORKS

Shanghai's (China) gas works companies are reporting heavy financial losses due to price reforms for raw coal. Last January the Chinese Government began allowing only 80 percent of the needed raw coal to be sold to gas producers at the price set by the government. In order to satisfy production demands, the rest of the coal had to be purchased at a much higher price. The result has been heavy losses.

The Shanghai Coking and Chemical General Plant reported a loss of $85,454 in January alone, according to the China Daily. The plant's deputy director, Z. Weisong, says the plant is expected to sustain losses of $20 million this year unless the price reform smooths out.

The plant has the capacity to produce 513 million cubic meters of pipe gas, or about 40 percent of the city's total output. It also produces 150,000 tons of coke each year.

With only an estimated 64 percent of the city's households using gas, Shanghai has launched the Trigeneration Project in an effort to have gas installed in all of its urban households by the end of 1995.

####

COAL/WATER SLURRY FUEL BEING PRODUCED AT TWO LOCATIONS IN CHINA

A coal/water mixture (CWM), also called liquefied coal, is being manufactured at two locations in China. One plant is in Mentougou in western Beijing and the other is in East China's Shandong Province.

The plant in Mentougou began operating in March and is designed to process 250,000 tons of liquefied coal per year. The project is a joint venture between the Beijing Mineral Bureau and a Swedish firm. The plant was funded by Chinese Government loans while the technology and major equipment items come from Sweden.

According to the China Daily, the Chinese Government views liquefied coal technology as one of its major products to be promoted in industrial development. Two tons of liquefied coal are said to be equivalent to 1 ton of crude oil. Compared with ordinary coal, liquefied coal is easier to transport, store and ignite, and causes little pollution.

The plant in Yanzhou, Shandong Province, began its first exportation of CWM in March when 3,300 tons of the product were shipped to Japan. The shipment is said to be the first transaction of this type between two countries. The CWM was manufactured by the Yanri CWM Company, Ltd., a joint venture between China and Japan. The product, made from high quality coal, water and additives, will be used as a replacement for heavy oil for power plants and boilers. It is cheaper than heavy oil and the company says it will generate less pollution.

The plant currently has an annual production capacity of 250,000 tons, but the capacity is expected to be increased to 1 million tons over the next 3 years.

####

SYNTHETIC FUELS REPORT, JUNE 1992

4-37
EXTERNALITIES ANALYSIS FAVORS COAL GASIFICATION

An analysis of environmental externalities by J.M. Speyer of Putnam, Hayes and Bartlett, Inc. shows that while externality costs penalize coal-based technologies, coal gasification combined cycle technology has the lowest externality costs compared to other coal-based technologies.

Speyer discussed his analysis in a paper presented at the Alternate Energy 1992 conference held in Charleston, South Carolina the end of April.

An externality is a cost imposed on society by an individual or firm where that firm does not pay the cost. For example, before environmental regulations were put in place, it was possible to emit large quantities of pollutants into the atmosphere. While operating costs to the polluting facility were minimized, the environmental costs paid by society included:

- Increased medical costs to people in the surrounding area
- Damages to crops and materials in the surrounding area
- Drop in neighboring property values

Regulatory Developments

Environmental externality costs have been required by several public utility commissions for new resource planning decisions. These costs vary considerably among states. Figure 1 shows the states where public utility commissions have already taken significant actions as well as those states that are likely to follow.

There is a potential for even more significant environmental externality regulations in the future. Externality costs could be applied to power purchase decisions. (California is already moving toward this approach.) Externality costs could also be applied to existing plants, affecting utilities' dispatch decisions.

The externality costs being proposed for use, in dollars per ton of emissions, have been increasing and may continue to increase. Table 1 gives selected state recommendations for externality costs.

Implications for Coal-Based Technologies

As illustrated by the figures in Table 2, externality costs can change the decision on what type of new plant to construct. The table gives the costs of various technologies with and without externalities.

FIGURE 1

STATES WHERE PUBLIC UTILITY COMMISSIONS ARE TAKING ACTION

SOURCE: SPEYER
**TABLE 1**

SELECTED STATE RECOMMENDATIONS FOR EXTERNALITY COSTS
(1992 $/Ton)

<table>
<thead>
<tr>
<th>States</th>
<th>Date</th>
<th>NO&lt;sub&gt;x&lt;/sub&gt;</th>
<th>SO&lt;sub&gt;x&lt;/sub&gt;</th>
<th>TSP</th>
<th>CO</th>
<th>VOC</th>
<th>CO&lt;sub&gt;2&lt;/sub&gt;</th>
<th>CH&lt;sub&gt;4&lt;/sub&gt;</th>
<th>N&lt;sub&gt;2&lt;/sub&gt;O</th>
</tr>
</thead>
<tbody>
<tr>
<td>California Low</td>
<td>1991</td>
<td>1,668</td>
<td>3,110</td>
<td>4,335</td>
<td>1,225</td>
<td>113</td>
<td>2.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>California High</td>
<td>1991</td>
<td>10,009</td>
<td>20,564</td>
<td>19,009</td>
<td>10,339</td>
<td>5,334</td>
<td>2.1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Massachusetts</td>
<td>1990</td>
<td>7,227</td>
<td>1,668</td>
<td>4,448</td>
<td>967</td>
<td>5,892</td>
<td>24.5</td>
<td>220</td>
<td>3,960</td>
</tr>
<tr>
<td>Minnesota</td>
<td>1992</td>
<td>1,640</td>
<td>4,060</td>
<td>2,380</td>
<td>920</td>
<td>13.6</td>
<td>220</td>
<td>3,960</td>
<td>3,600</td>
</tr>
<tr>
<td>Nevada</td>
<td>1991</td>
<td>7,264</td>
<td>1,666</td>
<td>4,465</td>
<td>982</td>
<td>1,260</td>
<td>23.5</td>
<td>235</td>
<td>4,423</td>
</tr>
<tr>
<td>New York</td>
<td>1990</td>
<td>6,496</td>
<td>1,361</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average</td>
<td></td>
<td>5,717</td>
<td>5,405</td>
<td>6,927</td>
<td>2,887</td>
<td>3,150</td>
<td>30.0</td>
<td>233</td>
<td>4,262</td>
</tr>
</tbody>
</table>

**TABLE 2**

TECHNOLOGY COSTS WITH AND WITHOUT EXTERNALITIES

<table>
<thead>
<tr>
<th>Technology</th>
<th>Cost Without Externalities ($/MWh)</th>
<th>Cost With Externalities ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Coal-Fired Boiler</td>
<td>47</td>
<td>99</td>
</tr>
<tr>
<td>Coal Gasification Combined-Cycle</td>
<td>46</td>
<td>80</td>
</tr>
<tr>
<td>Fluidized Bed Coal Combustion</td>
<td>51</td>
<td>101</td>
</tr>
<tr>
<td>Natural Gas Combined-Cycle</td>
<td>40 - 50</td>
<td>64 - 74</td>
</tr>
</tbody>
</table>

According to Speyer, the continued use of the vast reserves of coal in the United States will require cleaner means of coal-fired generation to compete with natural gas, renewable technologies and demand side management. Cleaner electricity generation (i.e., solar, wind, combined-cycle natural gas), even if it means a higher price, is encouraged. The development of more efficient and cost-effective pollution control equipment is also encouraged.

**Actions to Minimize the Impacts on Coal-Based Technologies**

In order to minimize the impacts on coal-based technologies, utilities must intervene in state regulatory proceedings to encourage the proper calculation of externality costs, and allow owners of new plants to purchase offsets from other sources (i.e., new controls at existing plants, planting trees outside the United States, etc.) so that the externality costs incurred by new plants will be the lower of market or administratively imposed values.

Speyer also says that pollution control options should be evaluated on a cost-benefit basis that includes externality costs.

###

MUTAGENICITY OF LURGI COAL TAR FRACTIONS STUDIED

X.B. Xu, et al., of the Research Center for Eco-Environmental Sciences and Y.Y. Wang of the State Health Department of California presented the results of coal tar sample analysis from the Lurgi gasification process at the Eighth Annual International Pittsburgh Coal Conference held in Pittsburgh, Pennsylvania last October.

Using Ames bioassay-directed chemical analysis, more than 600 compounds were identified from a low-temperature coal tar.
It was found that polycyclic aromatic hydrocarbons (about 24 percent in mass) accounted for 62 percent of the mutagenicity of the whole sample. Seventy-eight of them were identified by HRGC-MS and checked with GC retention indices as well as with some standards, and they are the major mutagens in the coal tar sample. More than 300 two to five ring aza-arenes and amines were tentatively identified from basic subfractions with higher mutagenicities. Among them, some compounds identified, such as amino-biphenyl, phenanthridine, benzocarbazol, benzacridine, and dibenzacridine, are known or suspected mutagens and carcinogens. Aliphatic amines and some five ring aza-arenes identified had not been reported before.

Background

Coal tar is a kind of well-known complex environmental sample with significant mutagenicity and carcinogenicity. It contains a wide range of compounds with different molecular weights, polarities and functionalities, and is widely used as a chemical feedstock and building material. The chemical composition and mutagenicity of various coal tar samples have been extensively studied for a number of years, but the identification of the specific compounds responsible for the mutagenic activity has been limited by the extreme complexity of the samples' composition.

Bioassay-directed chemical analysis, in which short-term bioassay was used in combination with chemical fractionation, could greatly simplify the process of identifying significant mutagens in complex materials, and has been successful in identifying known or suspected mutagens in diesel exhaust emission, synfuels and ambient air particulates.

The authors found that the chemical composition of the coal tar is complicated. Even though it had been fractionated in a three-step program before analysis, each subfraction still contained a lot of compounds.

The compounds with highest mutagenicity, however, were found in the B2 basic fraction, and more than 100 aza-arenes such as azapyrenes, azafuranthenes, azabenzopyrenes, and azabenzo-fluoranthenes, etc. and their alkyl substitutes, were tentatively identified in the d and f subfractions. Among them, some aza-arenes are known mutagens, but the biological activity of most four to five ring aza-arenes should be further studied, the authors concluded.
RECENT PUBLICATIONS

The following papers were presented at the Symposium on "Structure of Jet Fuels III" at the American Chemical Society meeting held in San Francisco, California, April 5-10:

Song, C. et al., "Compositional Differences Between Coal- and Petroleum-Derived Jet Fuels"


The following papers were presented at the American Chemical Society Division of Fuel Chemistry meeting held in San Francisco, California, April 5-10:

Srivastava, R.D., et al., "Catalysis in Direct Liquefaction of Coal"

Bockrath, B.C., et al., "Catalysis of Low Temperature Liquefaction by Molybdenum Sulfides"

Dosch, R.G., et al., "Development of Thin Film Hydrous Metal Oxide Supported Catalysts for Direct Coal Liquefaction"

Swanson, A.J., "Dispersed Molybdenum Catalysts for Liquefaction of Illinois No. 6 Coal"

Oyama, S.T., et al., "Transition Metal Carbides and Nitrides as Hydroprocessing Catalysts"

Gatsis, J.G., et al., "High-Severity Co-Processing"

Davis, B.H., "The Two-Alpha Value for Iron Fischer-Tropsch Catalysts: Fact or Fiction?"

Burgess, C.E., et al., "Relationships of Coal Structure to Molybdenum Catalyst Action in Liquefaction"


Song, C., et al., "Effects of Pore Structure and Support Type of Catalysts in Hydroprocessing of Heavy Coal Liquids"

Huang, L., et al., "Temperature-Programmed Catalytic Liquefaction of Low Rank Coal Using Dispersed Mo Catalyst"


Olson, E.S., et al., "Catalytic Reactions of Sulfided Iron- and Mixed Metal-Pillared Clays"


Rodriguez, N.M., et al., "In-Situ Model Studies of Metal Sulfide Catalysts"

Derbyshire, F., et al., "Dispersed Catalysts for Coal Dissolution"

Serio, M.A., et al., "Liquefaction of Water Pretreated Coals"

Comolli, A.G., et al., "Optimization of Reactor Configuration in Coal Liquefaction"

Strobel, B.O., et al., "IGOR—Taking the Short Cut in Coal Hydrogenation"

Wiser, W.H., et al., "High Conversion in Coal Liquefaction with Low HC Gas Production"

Klasson, K.T., et al., "Bioliquefaction of Coal Synthesis Gas"

Farcasu, M., et al., "Coprocessing of Coal and Waste Rubber"
Vaidyanathan, N., et al., "Liquefaction of a Subbituminous Coal in the Presence of Novel Microemulsion-Based Molybdenum Catalysts"


Ross, D.S., "Autoradiographic and Hydrothermal Probes of Interfacial Chemistry in Oil Shale and Coal"

McMillen, D.F., et al., "Hydrogen-Transfer in Retrograde Reaction—The Hero and the Villain"


Niksa, S., et al., "Predicting the Transient Devolatilization of Various Coals with Flashchain"

Huai, H., et al., "Determining Molecular Weight Distribution of Polar Coal Derived Liquids by Combined GC/MS and Vacuum TG Techniques"

Thwaites, M.W., et al., "Synthesis and Characterization of Activated Pitch-Based Carbon Fibers"

Jagtoyen, M., et al., "Activated Carbons from Bituminous Coals by Reaction with H$_3$PO$_4$: Influence of Coal Cleaning"

Lizzio, A.A., et al., "Production of Carbon Molecular Sieves from Illinois Coals"

Song, C., et al., "Specialty Chemicals and Advanced Materials from Coals: Research Needs and Opportunities"


Kruse, C.W., et al., "Oxidized Coal Char as a Catalyst: I. Characterization"

Pang, L.S.K., et al., "Coal as a Feedstock for Fullerene Production and Purification"


Provine, W.D., et al., "$^{13}$C NMR Spectroscopic Studies of Illinois #6 Coal and the Products of its Liquefaction"

Fletcher, T.H., et al., "Chemical Structure of Char in the Transition from Devolatilization to Combustion"

McArthur, C.A., et al., "The Effects of Chlorobenzene Pre-Treatment on the Low-Severity Liquefaction Behaviour of Pittsburgh No. 8 Coal"

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Ettinger, M.D., et al., "Dideuterium Incorporation During the Coprocessing Reaction of Lloydminster Petroleum Resid and Illinois No. 6 Coal in D$_2$."

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Song, C., et al., "Temperature-Programmed Liquefaction of Low-Rank Coals in H-Donor and Non-Donor Solvents"

Sharma, R.K., et al., "Catalysts for Aqueous/CO Liquefaction of Subbituminous Coal"

Merritt, S.D., et al., "Hot Vapor Treatment of Gulf Province Lignites"
Chatterjee, K., et al., "Coal Solubilization Using Metal Alkoxides in Refluxing Alcohols"

Shams, K., et al., "Enhanced Low Severity Coal Liquefaction Using Selective Calcium Removal"

The following articles appeared in *Energy & Fuels*, March/April 1992:

Nelson, P.F., et al., "Effects of Ion-Exchanged Calcium on Brown Coal Tar Composition as Determined by Fourier Transform Infrared Spectroscopy"

Solomon, P.R., et al., "An Empirical Model for Coal Fluidity Based on a Macromolecular Network Pyrolysis Model"

Landais, P., et al., "Spectroscopic Analyses of Aromatic Hydrocarbons Extracted from Naturally and Artificially Matured Coals"

Miura, K., et al., "Flash Pyrolysis of Coal in Solvent Vapor for Controlling Product Distribution"

**COAL - PATENTS**

"Utilization of Slag from Coal Gasification Systems," Seymour Alpert, Vas Choudhry, Donald Meisel - Inventors, Electric Power Research Institute, United States Patent Number 5,091,349, February 25, 1992. A low density aggregate product and method for making the same utilizing coal ash slag resulting from a typical coal gasification system wherein the resulting aggregate product has a lower density than the initial coal ash slag. The coal ash slag is combined with a small amount of a binder and then fired for a predetermined time and temperature to produce the aggregate. Also, by heating the coal ash slag and binder, a gaseous efflux is emitted to form interlaced channels throughout the aggregate which have a characteristic length and diameter.

"Coal Gasification Apparatus Using Coal Powder," Kenichi Kikuchi, Tetsuro Mochizuki, Akio Suzuki - Inventors, Nippon Kokan, United States Patent Number 5,089,031, February 18, 1992. A coal gasification apparatus using coal powder supplies coal powder, along with oxygen or air and steam, into a reaction chamber, supplies the char produced in the reaction chamber or the char and coal, along with oxygen or air and steam into combustion chamber formed in the lower part of the reaction chamber and burns the same in the combustion chamber to maintain the temperature therein at about 1,600°C, and forms agglomerated bed of fluidized coal having a temperature between 900° and 1,300°C.

"Apparatus for Producing Generator Gas and Activated Carbon from Solid Fuels," Herwig Michel-Kim - Inventor, United States Patent Number 5,089,030, February 18, 1992. A method and apparatus for producing generator gas and activated carbon from solid fuels. A first gasification stage is supplied with fuel by an underfeed charging system and preheated air, the air and fuel being supplied in the same direction. In a second gasification stage and accompanied by the supply of secondary air, an intermediate gasification takes place. Finally, in a third gasification stage, the gas is reacted with glowing coke or charcoal, and the heat of the exiting gas is used for heating the air. The fuel centrally entering the first gasification stage is led from the inside to the outside and then upwards. Part of the entering fuel is precombusted in a precombustion chamber linked with the supply of the preheated air for reducing the oxygen content of the preheated air. In the intermediate gasification stage, the gas with the admixed air is passed through a Venturi nozzle or tube with a diffuser. The flame entrained from the first gasification stage is at least partly returned to the throat of the Venturi tube. The return is assisted both by vacuum in the Venturi tube and mechanically.

"High Temperature Ceramic Particulate Filter," Jesse Brown, Nancy Brown, Sandra Gonzalez - Inventors, Center for Innovative Technology, Virginia Polytechnic Institute, Virginia Tech Intellectual Properties, United States Patent Number 5,087,277, February 11, 1992. A high temperature ceramic filter is produced from a composition containing refractory cement, aggregate, pore forming additives, and sintering agents. The pore forming additives are synthetic or organic powders or fibers which sublime, melt, or otherwise disintegrate to produce in situ pores in the cement during the refractory treatment of a cast filter. The filters produced are permeable to high temperature gases commonly found in a coal furnace and can be used to collect particulate matter present in those gases.

"Inclined Fluidized Bed System for Drying Fine Coal," John Boysen, Chang Cha, Norman Merriam - Inventors, Western Research Institute, United States Patent Number 5,087,269, February 11, 1992. Coal is processed in an inclined fluidized bed dryer operated in a plug-flow manner with zonal temperature and composition control, and an inert fluidizing gas, such as carbon dioxide or combustion gas. Recycled carbon dioxide, which is used for drying, pyrolysis, quenching, and cooling, is produced by partial decarboxylation of the coal. The coal is heated sufficiently to mobilize coal tar by further pyrolysis, which seals micropores upon quenching. Further cooling with carbon dioxide enhances stabilization.
"Integrated Air Separation Plant-Integrated Gasification Combined Cycle Power Generator," Rodney Allam, Anthony Topham - Inventors, Air Products and Chemicals, Inc., United States Patent Number 5,081,845, January 21, 1992. An integrated cryogenic air separation unit power cycle system is disclosed wherein the air separation unit (ASU) is operated at elevated pressure to produce moderate pressure nitrogen. The integrated cycle combines a gasification section wherein a carbon source, e.g., coal, is converted to fuel and combusted in a combustion zone. The combustion gases are supplemental with nitrogen from the air separation unit and expanded in a turbine. Air to the cryogenic air separation unit is supplied via a compressor independent of the compressor used to supply air to the combustion zone used for combusting the fuel gas generated in the gasifier system.

"Combined Gas and Steam Turbine Plant with Coal Gasification," Hermann Bruckner, Lothar Stadie - Inventors, Siemens AG, United States Patent Number 5,079,909, January 14, 1992. A combined gas and steam turbine plant includes a coal gasification system having a heat exchanger device and preferably a gas scrubber connected downstream of the heat exchanger device. A gas turbine part is connected downstream of the coal gasification system and has an exhaust gas turbine. A steam generator system receives exhaust gas from the exhaust gas turbine and has an economizer heating surface, an evaporator heating surface, and superheater heating surfaces. A steam turbine part is connected to the steam generator system and has a high-pressure feedwater system. The heat exchanger device of the coal gasification system is connected in such a way that it directly transfers or gives up thermal energy for feedwater heating or steam generation to the high-pressure feedwater system of the steam turbine part.

"Coal Gas Productions Coal-Based Combined Cycle Power Production," Frank Mach, Peter Mach - Inventors, Northern States Power Company, United States Patent Number 5,078,752, January 7, 1992. An apparatus for the production of hot pressurized coal gas for use, for example, in power generation is provided. The apparatus includes a step of subjecting coal fuel to staged slugging combustion, to generate raw gas and liquid slag. The liquid slag is separated from the raw gas, and the raw gas is then subjected to a mixing and separation procedure, wherein it is treated and cleaned, for example, of sulfur dioxide content. The raw gases may then be further treated and utilized to advantage in power generation. A preferred arrangement for conducting the process is also described.

"Apparatus for Removing Suspended Solids from a Liquid," Phillip Rose - Inventor, Chevron Research and Technology Company, United States Patent Number 5,076,915, December 31, 1991. Disclosed is a gravity settler for separating finely divided solids such as coal fines from a liquid such as a mixture of coal oil and agglomerating agent by agglomeration. A feed slurry comprising finely divided solids and a liquid mixture of product oil and an agglomerating agent is discharged into a specially shaped duct which promotes formation of agglomerated solids while minimizing turbulence in the remainder of the vessel. The agglomerated solids separate from the liquid by gravity and are washed as they leave the settler while the clarified liquid is discharged from the top of the settler. A method for separating suspended solids from a liquid by agglomeration is also disclosed.

"Coal Treatment Process and Apparatus Therefor," John Getsoin - Inventor, Arcanum Corporation, United States Patent Number 5,076,812, December 31, 1991. A process for demineralizing and agglomerating coal in which the coal is subjected to pulverization in order to separate mineral matters therefrom and resulting coal particles are agglomerated through the use of a bridging liquid as a binder. Oversized coal particles are recycled in a grinding circuit until they are reduced to an acceptable size and bridging liquid is removed from the microagglomerates of coal in a low shear reactor and recovered for reuse in the process.

"Coal Hydroconversion Process Comprising Solvent Extraction and Combined Hydroconversion and Upgrading," Claude Culross, Steve Reynolds - Inventors, Exxon Research and Engineering Company, United States Patent Number 5,071,540, December 10, 1991. An improved process for the hydroconversion of coal comprising pretreating coal in an aqueous carbon monoxide-containing environment, followed by extracting a soluble hydrocarbon material from the coal, and subsequently hydroconverting the extracted material in a hydroconversion reactor with a high catalyst loading to obtain a nearly finished product with low heteroatom levels. The extracted material consists of a relatively hydrogen-rich material which is readily converted to valuable liquid products in high yield. The residue from the extraction stage is relatively hydrogen deficient material which can be gasified to produce hydrogen and carbon monoxide for the hydroconversion and pretreatment stages, respectively.

"Process for the Production of Liquid Steel from Iron Containing Metal Oxides," Henry Bueno, Gerardo Contreras, Oscar Dam, Yura Gancthev, Nicolas Guevara - Inventors, Cvg-Siderurgica Del Orinoco CA, United States Patent Number 5,069,716, December 3, 1991. The present invention relates to an overall direct smelting process which provides for separating the carburization function from the heating function to permit separate control of the individual functions. One embodiment of the smelting reactor is divided into a carburization/smelting section and a heating section with a substantial recirculation of the molten product from the heating section back to the carburization/smelting section. The heating section also serves as a slag/metal separa-

4-44
SYNTHETIC FUELS REPORT, JUNE 1992
Carburization is achieved by injection of solids (fine coal mixed with slagging agents), where desired. Gas generating solids or inert gases are injected into a lift pipe to provide a motive force for circulation of the molten metal. The circulation rate through the system is a function of the injected solid composition, the mass flow rate of the solids injected into the lift pipe and the lift pipe geometry. The liquid is discharged from the carburization/smelting chamber into a heating chamber where the pressure is preferably lower than in the carburization/smelting chamber, and where submerged combustion occurs in the slag. Weirs are provided for slag removal and discharge of the finished metal and a recirculation passageway or tube is provided to feed a substantial portion of the heated metal back into the carburization/smelting chamber. A compact high efficiency direct smelting process is thus achieved.

"Two-Stage Coal Gasification and Desulfurization Apparatus," Larry Bissett, Larry Strickland - Inventors, United States Department of Energy, United States Patent Number 5,069,685, December 3, 1991. The present invention is directed to a system which effectively integrates a two-stage, fixed-bed coal gasification arrangement with hot fuel gas desulfurization of a first stream of fuel gas from a lower stage of the two-stage gasifier and the removal of sulfur from the sulfur sorbent regeneration gas utilized in the fuel-gas desulfurization process by burning a second stream of fuel gas from the upper stage of the gasifier in a combustion device in the presence of calcium-containing material. The second stream of fuel gas is taken from above the fixed bed in the coal gasifier and is laden with ammonia, tar and sulfur values. This second stream of fuel gas is burned in the presence of excess air to provide heat energy sufficient to effect a calcium-sulfur compound forming reaction between the calcium-containing material and sulfur values carried by the regeneration gas and the second stream of fuel gas. Any ammonia values present in the fuel gas are decomposed during the combustion of the fuel gas in the combustion chamber. The substantially sulfur-free products of combustion may then be combined with the desulfurized fuel gas for providing a combustible fluid utilized for driving a prime mover.
STATUS OF COAL PROJECTS

COMMERCIAL AND R&D PROJECTS (Underline denotes changes since March 1992)

ACME COAL GASIFICATION DESULFURING PROCESS – ACME Power Company (C-9)

American Plastics and Chemicals, Inc. (APAC), based in Los Angeles, California, signed an agreement in 1990 to acquire the Acme Power Plant located in Sheridan, Wyoming. The Acme facility is a 12 megawatt coal-fired steam plant, which has been idle since 1977 when it was shut down in anticipation of new power generating facilities.

APAC formed Acme Power Company, a wholly-owned subsidiary, which will bring the Acme plant up to current environmental standards with appropriate emission controls prior to bringing it back on-line. The plant will initially operate in a conventional mode, using locally purchased coal. In addition to providing revenue through electric power sales, the plant, with its modular design, will provide for a long term commercial demonstration of the desulfurizing coal gasification process which APAC has optioned.

The project will demonstrate the commercial viability of the desulfurizing gasification technology and make it ready for the retrofit of other coal-fired facilities.

The ACME coal gasification process can emphasize either acetylene production from calcium carbide or power generation, depending on the coal-to-limestone ratio used. Increasing the limestone component produces byproduct calcium carbide, from which acetylene can be produced. Increasing the coal component results in byproduct calcium sulfide.

APAC's consulting engineers estimate that it will take about one year to bring the plant on-line after power sale contracts, environmental permits, and project financing have been put in place.

Project Cost: Undisclosed

ADVANCED COAL LIQUEFACTION PILOT PLANT AT WILSONVILLE – Electric Power Research Institute (EPRI) and United States Department of Energy (DOE) (C-10)

EPRI assumed responsibility for the 6 tons per day Wilsonville, Alabama pilot plant in 1974. This project had been initiated by Southern Company and the Edison Electric Institute in 1972. The Department of Energy began cofunding Wilsonville in 1976.

The initial thrust of the program at the pilot plant was to develop the SRC-I process. That program evolved over the years in terms of technology and product slate objectives. Kerr-McGee Critical Solvent Deashing was identified as a replacement for filtration which was utilized initially in the plant and a Kerr-McGee owned unit was installed in 1979. The technology development at Wilsonville continued with the installation and operation of a product hydrotreating reactor that has allowed the plant to produce a No. 6 oil equivalent liquid fuel product as well as a very high distillate product yield.

The Wilsonville Pilot Plant was subsequently used to test the Integrated Two-Stage Liquefaction (ITSL) process. In the two stage approach, coal is first dissolved under heat and pressure into a heavy, viscous oil. Then, after ash and other impurities are removed in an intermediate step, the oil is sent to a second vessel where hydrogen is added to upgrade the oil into a lighter, more easily refined product. A catalyst added in the second stage aids the chemical reaction with hydrogen. Catalytic hydrotreatment in the second stage accomplishes two distinct purposes: (1) higher-quality distillable products are produced by mild hydroconversion, and (2) high residuum content, donor rich solvent is produced for recycle to the coal conversion first stage reactor. Separating the process into two stages rather than one keeps the hydrogen consumption to a minimum. Also, mineral and heavy organic compounds in coal are removed between stages using Kerr-McGee's Critical Solvent Deashing unit before they can foul the catalyst.

ITSL results showed that 30 percent less hydrogen was needed to turn raw coal into a clean-burning fuel that can be used for generating electricity in combustion turbines and boilers. Distillable product yields of greater than 60 percent MAP coal were demonstrated on bituminous coal. Similar operations with sub-bituminous coal demonstrated distillates yields of about 55 percent MAF. This represents substantial improvement over single stage coal liquefaction processes.

Tests then concentrated on testing both types of coals with the deashing step relocated downstream of the catalytic hydrotreatment. Results showed that previous improvements noted for the two-stage approach were achievable (no loss in catalyst activity). Lower product cost was indicated for this reconfigured operation in that the two reactor stages may be coupled as part of one system. The results from the reconfigured operation also indicated the potential for further improvements in product quality and/or productivity through use of the coupled-reactor approach. This was confirmed in tests which used a truly coupled, two-stage thermal-catalytic reaction system in conjunction with an improved hydrotreatment catalyst. The nickel based catalyst (AMOCAT 1-C) was developed by Amoco Corporation, a program co-sponsor. In that test, coal space velocity was increased by 60 to 90 percent over previous operations, while catalyst productivity doubled. Furthermore, an improved configuration was developed and proven out, whereby only the net vacuum bottoms are deashed, thereby reducing the equipment size substantially.

Recent work emphasized identifying potential cost benefits through advantageous feedstock selecting. This includes the use of lower ash (Ohio) coal and lower cost (Texas) lignite. The Ohio coal run results suggest that deep cleaning of the coal prior to liquefaction can increase distillate yield by 7-8 percent.

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

Work using the Amocat catalyst indicated the need to improve first stage reactor design. This led to modification of the L/D criteria which resulted in increased productivity corresponding to improved mixing. This improvement was also demonstrated with low-rank (Powder River Basin) coal. Further improvements for low-rank coal liquefaction were demonstrated using dispersed molybdenum catalyst in place of extracted catalyst in the first reaction. In addition to increasing productivity, the dispersed catalyst permits the use of a less expensive entrained flow (bubble column) reactor in place of the fluidized (ebullated) bed which is still required in the second reactor. Dosage of less than 200 ppm was effective, thus no catalyst recovery is required.

Project Cost: Construction and operating costs (through calendar 1990): $139 million

ADVANCED POWER GENERATION SYSTEM - British Coal Corporation, United Kingdom Department of Energy, European Commission, PowerGen, GEC/Alsthom (C-15)

British Coal Corporation is carrying out a research program to develop an advanced coal fired power generation system. In this system coal is gasified to produce a fuel gas which is used to drive a gas turbine. The waste heat recovery from the gas turbine is then integrated with a fluidized bed combustion steam turbine cycle.

The integrated system is expected to have an efficiency of about 45 percent.

At present the different technologies are being developed separately. A 12 tonne per day, air blown, pressurized, spouted bed gasifier developed at the Coal Research Establishment, Gloucestershire, started operating in 1990. This is providing design data for the next scale of plant (15 tonne/hr).

The combustor, necessary to optimize the steam cycle and to burn unconverted carbon from the gasifier, can be either a CFBC or a PFBC. A 12 tonne per day CFBC is being built, for operation in 1991, alongside the gasifier.

At Grimethorpe, British Coal's large scale experimental PFBC is producing a coal derived gas which is passed through an experimental gas turbine. In conventional PFBC, coal is burned under pressure and the hot pressurized gases are fed directly into a gas turbine. However the operating temperature of a PFBC is usually only about 850°C to avoid sintering of the ash. This comparatively low temperature at the gas turbine inlet limits efficiency.

To overcome this, British Coal engineers proposed a topping cycle. It entails burning a fuel gas in the hot PFBC combustion gas in the gas turbine combustor, at a temperature to 1,260°C or more. In the current Grimethorpe experiment the fuel gas is propane. In due course it will be provided by the 15 tonne per hour gasifier.

The gas turbine operation is funded by British Coal, United Kingdom Department of Energy, PowerGen, GEC/Alsthom and EPRI. The gasifier work is funded by British Coal and the European Community.

AECI AMMONIA/METHANOL OPERATIONS - AECI LTD. (C-20)

AECI operates a 100 ton per day methanol facility and a 1,000 ton per day ammonia plant at its Modderfontein works near Johannesburg. The plant uses six Koppers-Totzek two-headed gasifiers operating at 1,600 degrees C and atmospheric pressure to generate synthesis gas from sub-bituminous South African coal of low sulfur and high ash content. The ammonia plant, which utilizes conventional technology in the synthesis loop, has been in service since 1974 while the methanol unit, which employs ICI's low pressure process, has been running since 1976. The plant is operating very satisfactorily at full capacity.

AECI has successfully completed the piloting of a methanol to hydrocarbons process using Mobil zeolite catalyst. The design of a commercial scale ethylene plant using this process has been completed.

AECI has also pursued development programs to promote methanol as a route to transportation fuel. Test programs include operation of a test fleet of vehicles on gasoline blends with up to 15 percent methanol, operation of other test cars on neat methanol, and operation of modified diesel trucks on methanol containing ignition promoters, trademarked "DIESANOL" by AECI. "DIESANOL" is currently being evaluated as a diesel fuel replacement in a number of countries.

AECI has completed a detailed study to assess the economic feasibility of a coal-based synthetic fuels project producing gasoline and diesel using methanol conversion technology. The results of this study were encouraging technically, but lacked economic feasibility, with the result that further work in this area has been suspended.

Project Cost: Not disclosed
AMAX/EMRC MILD GASIFICATION DEMONSTRATION – AMAX, University of North Dakota Energy and Minerals Research Center (EMRC) (C-31)

AMAX is considering a 1,000 ton per day plant at its Chinook Mine in Indiana. A fast fluidized-bed reactor will be used for mild gasification of this caking coal. It is planned to produce a diesel type fuel, as well as pure chemicals such as benzene and phenol.

AMAX conducted prefeasibility studies and concluded that favorable economics depend upon upgrading the mild gasification chars to a higher value product. This is because char has lower volatile matter content and higher ash content than the starting coal. These characteristics make char a low value utility fuel. The char will be cleaned by simple physical methods, then further processed into a metallurgical coke substitute (pellets or briquettes) and possibly to activated carbon for the pollution control industry. The location of this project offers distinct marketing advantages for these products.

A 100 pound per hour mild gasification process demonstration unit was started up at the Energy and Environmental Research Center in Grand Forks, North Dakota in the fall of 1990.

BEWAG GCC PROJECT - BEWAG AG, EAB Energie-Anlagen Berlin GmbH, Ruhrkohle Oel und Gas GmbH, and Lurgi GmbH (C-35)

BEWAG AG of Berlin, in cooperation with others listed, has started to evaluate a project called "Erection and testing of a GCC based demonstration plant."

The project's ultimate goal is the erection of a 195 megawatt pressurized circulating fluidized bed (CFB) combined cycle power plant, with 95 megawatts obtained from the gasification, and 100 megawatts from the combustion section. As both sections may be operated individually, the 52 megawatt gas turbine could also operate on oil or natural gas.

An engineering study to investigate the general feasibility of both pressurized CFB gasification and the coupling of pressurized CFB gasification with atmospheric CFB combustion was concluded in 1986.

A second phase component testing program, costing DM12 million and supported by the German Ministry of Research and Technology, was carried out by a working group made up of BEWAG/EAB (Berlin), Ruhrkohle Oel and Gas GmbH (Bottrop), and Lurgi GmbH (Frankfurt), under the project leadership of EAB Energie-Anlagen Berlin GmbH.

In this study, the design risks of key components were eliminated by detailed tests at pressurized charging valves and the condenser for carbonized residues. The availability of hot gas cleaning was proved with test series at electrostatic precipitators and tube filters. The now finished study allows the enlargement to a scaled up power plant. This power plant design shows a low grade of complexity on the gasification plant (a result of the dry procedure in gas cleaning) and minimized demand of coal and lime quality. The emission of exhaust fumes is reduced by the well known low emission of the CFB coal combustion and the high efficiency grade of the combined cycle. The only residues are flue gases and ash. The flue gas does not need to be after-treated. As a result of these characteristics, the study found a minimal risk for investment.

BHEL COAL GASIFICATION PROJECT – Bharat Heavy Electricals Limited (India) (C-40)

Bharat Heavy Electricals Limited (BHEL), of Vikas Nagar, Hyderabad, India, considers fluidized bed coal gasification as a long term perspective for combined cycle power generation. An 18 ton per day coal pilot scale process and equipment development unit (PEDU) has been built.

BHEL, as a manufacturer of power generation equipment, has been involved in research and development activities related to advanced power systems. These include coal gas-based combined cycles.

BHEL’s involvement in the development of coal gasification concerns the better and wider utilization of high ash, low grade Indian coals. The coals normally available for power generation are non-caking and have ash content in the range of 25 to 45 percent by weight. The coals have high ash fusion temperature in the range 1,523-1,723 K. In the PEDU, coal is gasified by a mixture of air and steam at around 1,173 K and at a pressure of 1.013 MPa.

Phase I of the fluidized bed coal gasification test program in the pilot scale plant is continuing. The plant was commissioned in early 1989 and further test trials were conducted.

Phase II of the fluidized bed coal gasification program, basic engineering of a demonstration scale 150 ton per day coal capacity gasification plant has been completed. The demonstration plant will be integrated with the existing 6.2 megawatt electrical gas turbine/steam turbine combined cycle plant.

Project Cost: Not disclosed
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

BHEL COMBINED CYCLE DEMONSTRATION PLANT – Bharat Heavy Electicals Limited (India) (C-50)

Bharat Heavy Electicals Limited (BHEL) of Hyderabad, India is carrying out a broad-based research program aimed at better and wider utilization of Indian coal resources. One phase of that program has involved building a small gasification combined cycle demonstration plant using a fixed bed coal gasifier.

The combined cycle demonstration plant (CCDP) is installed at the coal research and development complex of BHEL at Trichy. The net power generation capacity at full load is 6.2 megawatts. The CCDP scheme consists of an air blown, fixed bed, pressurized coal gasifier, an industrial gas turbine firing the low-BTU coal gas, and a waste heat recovery steam generator behind the gas turbine, which supplies a conventional steam turbine/generator.

The plant was commissioned in March 1988 and has been in test operation since then, testing various coals with ash content in the 25 to 40 percent range.

The test program on this plant has been completed and the plant's performance has been evaluated. A comprehensive test program was initiated for exploiting the moving bed gasification technology for commercialization.

Project Cost: Not disclosed

BOTTROP DIRECT COAL LIQUEFACTION PILOT PLANT PROJECT – Ruhrkohle AG, Veba Oel AG, Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia, and Federal Minister of Research and Technology of Germany (C-60)

During operation of the pilot plant the process improvements and equipment components have been tested. The last improvement made was the operation of an integrated refining step in the liquefaction process. It worked successfully between late 1986 and the end of April 1987. Approximately 11,000 tons of refined oil were produced from 20,000 tons of coal in more than 2,000 operating hours.

By this new mode of operation, the oil yield is increased to 58 percent. The formation of hydrocarbon gases is as low as 19 percent. The specific coal throughput was raised up to 0.6 tons per cubic meter per hour. Furthermore, high grade refined products are produced instead of crude oil. The integrated refining step causes the nitrogen and oxygen content in the total product oil to drop to approximately 100 ppm and the sulfur content to less than 10 ppm.

Besides an analytical testing program, the project involves upgrading of the coal-derived syncrude to marketable products such as gasoline, diesel fuel, and light heating oil. The hydrogenation residues were gasified either in solid or in liquid form in the Ruhrkohle/Ruhrchemie gasification plant at Oberhausen-Holten to produce syngas and hydrogen.

The development program of the Coal Oil Plant Bottrop was temporarily suspended in April 1987. Reconstruction work for a bivalent coal/heavy oil process was finished at the end of 1987. The plant capacity is 9 tons/hour of coal or alternatively 24 tons/hour of heavy vacuum residual oil. The first "oil-in" took place at the end of January 1988. Since then approximately 325,000 tons of heavy oil have been processed. A conversion rate over 90% and an oil yield of 85% have been confirmed.

The project was subsidized by the Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia and since mid-1984 by the Federal Minister of Research and Development of the Federal Republic of Germany.

Project Cost: DM830 million (by end-1987)

BRITISH COAL LIQUID SOLVENT EXTRACTION PROJECT – British Coal, British Department of Energy, European Economic Community, Ruhrkohle AG, Amoco (C-70)

British Coal is operating a 2.5 tons per day pilot plant facility at its Point of Ayr site, near Holywell in North Wales utilizing its Liquid Solvent Extraction Process, a two-stage system for the production of gasoline and diesel from coal. In the process, a hot, coal-derived solvent is mixed with coal. The solvent extract is filtered to remove ash and carbon residue, followed by hydrogenation to produce a syncrude boiling below 300 degrees C as a precursor for transport fuels and chemical feedstocks. Studies have confirmed that the process can produce high yields of gasoline and diesel very efficiently—work on world-wide coals has shown that it can liquefy economically most coals and lignite and can handle high ash feedstocks.

British Coal dries and pulverizes the coal, then slurries it with a hydrogen donor solvent. The coal slurry is pressurized and heated, then fed to a digester that dissolves up to 95 percent of the coal. The digest is cooled, depressurized and filtered to remove mineral matter and undisolved coal. A fraction of the solvent washes the filter cake to displace the coal extract solution; residual wash oil is recovered by a vacuum that dries the filter cake.

The coal extract solution is then pressurized, mixed with hydrogen and heated before being fed to the ebulliating bed hydrocracking reactors.

SYNTHETIC FUELS REPORT, JUNE 1992
The product from this stage is distilled to recover the recyclable solvent and produce LPG (propane and butane), naphtha and mid-distillate. A byproduct pitch stream is siphoned off although material in this boiling range is primarily returned to the digestion stage as part of the solvent. The remaining streams consist of light hydrocarbon gases and heterogases formed from the nitrogen and sulfur in the coal.


BROKEN HILL PROJECT -- The Broken Hill Proprietary Company Ltd. (C-80)

The Broken Hill Proprietary Company Limited has been investigating the production of transport fuels from coal via continuous hydroliquefaction, since 1976 at their Melbourne Research Laboratories in Clayton, Victoria, Australia. The current continuous processing unit was built in 1980, and since 1982 it has been used to study medium severity hydroliquefaction. Routinely the primary liquefaction reactor has a throughput of 3 kg slurry per hour, with a coal to oil ratio of 40:60, and employs a H₂ pressure of 25 MPa, and a temperature of 450 degrees C.

The main objective is to evaluate and develop alternative hydroliquefaction strategies and to test the efficacy of such strategies for a small indicative range of Australian coals. The unit is capable of single stage or two-stage operation, and allows for use of disposable catalyst in stage 1 and for recycle of separated solids to stage 1, if desired. Currently, oil yields of between 35% and 55% (DAF) coal have been obtained, depending on coal feed and process type.

Batch micro-autoclaves (50 cubic centimeters) are used extensively in support of the continuous hydroliquefaction unit. Particular emphasis has been placed on matters relating to hydrogen transfer. An in-house solvent hydrogen donor index (SHDI) has been developed and has proven to be a valuable tool in process development and control, especially in non-catalytic two-stage hydroliquefaction. The research has also been concerned with the upgrading (refining) of product syncrudes to specification transport fuels. Experimental studies have included hydrotreating, hydrocracking and reforming, for the production of gasoline, jet fuel and diesel fuel. Jet and diesel fuel combustion quality requirements, as indicated by smoke point and cetane number for example, have been achieved via severe hydrotreatment. Alternatively, less severe hydrotreatment and blending with suitable blendstocks has also proven effective. High octane unleaded gasolines have been readily produced via consecutive hydrotreating and reforming.

Substantial efforts have been directed towards understanding the chemical basis of jet and diesel fuel specification properties. As a result novel insights into the chemical prerequisites for acceptable fuel quality have been gained and are valid for petroleum derived materials and for many types of synthetic crudes. Considerable effort has also been directed towards developing specialized analytical methodology, particularly via NMR spectroscopy, to service the above process studies.

The work is supported under the National Energy Research Development and Demonstration Program (NERD&DP) administered by the Australian Federal Government.

Project Cost: Not disclosed

BROOKHAVEN MILD GASIFICATION OF COAL -- Brookhaven National Laboratory and United States Department of Energy (C-90)

A program is under way on mild gasification of coal to heavy oils, tars and chars under mild process conditions of near atmospheric pressure and temperatures below 750 degrees C. A test matrix has been designed to obtain the process chemistry, yields and characterization of liquid product over a wide range of temperature (500 to 750 degrees C), coal particle residence time (10 seconds to 50 minutes), heatup rate (50 degrees C/second to 10⁷ degrees C/second) coal particle size (50 to 300 microns) and additives (slaked lime, recycle ash, silica flour, recycle char). A combined entrained and moving bed reactor is being used to obtain the data. Four different types of coal have been tried, Kentucky No. 8 and Pittsburgh No. 8 bituminous coal, a Mississippi lignite and a Wyodak subbituminous. Generally the yields of oils from bituminous coals range between 20-25 percent (MAF), and about 15 percent for subbituminous coal.

A process for producing clean carbon black and coproduct hydrogen-rich gas and liquid methanol competitive with current prices of oil and gas is being developed. The HYDROCARB process can use any carbonaceous feedstock including coal, char, biomass and municipal solid waste. HYDROCARB provides clean fuel for heat engines (turbines and diesels), and offers reduced CO₂ emissions.

Project Cost: $200,000

CALDERON ENERGY GASIFICATION PROJECT -- Calderon Energy Company, United States Department of Energy (C-95)

Calderon Energy Company is constructing a coal gasification process development unit. The Calderon process targets the clean production of electrical power with coproduction of fuel methanol.

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

Phase I activity and Phase II, detailed design, have been completed. Construction of the process development unit (PDU) was completed in 1990. Test operation began in October 1990 and ran at 50 percent capacity during the early stages.

The PDU will demonstrate the Calderon gasification process. In the process, run-of-mine high sulfur coal is first pyrolyzed to recover a rich gas (medium BTU), after which the resulting char is subjected to airblown gasification to yield a lean gas (low BTU gas). The process incorporates an integrated system of hot gas cleanup which removes both particulate and sulfur components of the gas products, and which cracks the rich gas to yield a syngas (CO and H₂ mix) suitable for further conversion (e.g., to methanol). The lean gas is suitable to fuel the combustion turbine of a combined cycle power generation plant. The PDU is specified for an operating pressure of 350 psig as would be required to support combined cycle power production.

The pilot project, designed to process 25 tons of coal per day, is expected to operate for six to twelve months while operating data is gathered and any "bugs" in the system are worked out.

The federal government has contributed $12 million toward project costs, with another $1.5 million coming from the Ohio Coal Development Office.

Calderon Energy has obtained certification from the Federal Energy Regulatory Commission as a Qualifying Facility for a commercial site in Bowling Green, Ohio. Calderon filed a proposal under the Clean Coal Technology program Round 3 to build a cogeneration facility supplying 87 megawatts of electricity and 613 tons of methanol per day. The project did not receive funding, however, in Round 3 or 4. A preliminary design and cost estimate has been prepared by Bechtel. Calderon is negotiating with Toledo Edison to sell the electricity which would be produced.

Project Cost: Total Cost $242 million, PDU $20 million

CHARFUEL PROJECT – Wyoming Coal Refining Systems, Inc., a subsidiary of Carbon Fuels Corporation (C-110)

Wyoming Coal Refining Systems, Inc. (WCRS) has secured about half the financing required for a 150 ton per day Charfuel project at the Dave Johnston Power Plant near Glenrock, Wyoming. The plant would include gas processing and aromatic naphtha recovery with off-site hydrotreating and product quality verification.

The State of Wyoming has contributed $8 million and has committed to provide an additional $8.5 million in assistance, contingent on WCRS raising a certain amount of private capital. WCRS has secured over $4 million in capital and contributions.

WCRS has solicited the U.S. Department of Energy for funding under the Clean Coal Technology program but was turned down for support in Round 4 of the program in 1991.

The project involves demonstrating a coal refining process. The first step is "hydrodisproportionation" which the company says is based on short residence time flash volatilization. Resulting char may be mixed back with process-derived liquid hydrocarbons to make a stable, high-BTU, pipelineable slurry fuel. This compliance fuel could be burned in coal-fired or modified oil-fired burners. The char can also be used as a feedstock for integrated combined cycle gasification (IGCC). Additional products manufactured during the refining process would include ammonia, sulfur, methanol, MTBE, BTX, and aromatic naphtha.

WCRS has completed a program which verified the design of the injector/mixer system. This work was cofunded by the Department of Energy and conducted at the Western Research Institute in Laramie, Wyoming. WCRS is presently in the design phase of an 18 ton per day pilot unit which will integrate the Charfuel hydrocracker with commercially available processes to optimize the operating conditions for the 150 ton per day project as well as commercial facilities.

Project Cost: $24.5 million

CHEMICALS FROM COAL – Tennessee Eastman Co. (C-120)

Tennessee Eastman Company, a manufacturing unit of Eastman Chemical Company, operates its chemicals from coal complex at Kingsport, Tennessee at the design rate of 1,100 short tons per day. The Texaco coal gasification process is used to produce the synthesis gas for manufacture of 1.2 billion pounds per year of acetic anhydride. Methyl alcohol and methyl acetate are produced as intermediate chemicals, and sulfur is recovered and sold.

The completion of a $200 million expansion program in October 1991 added two new chemical plants to the original complex, doubling its output of acetyl chemicals from coal.

Project Cost: Unavailable
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

CHINA ASH AGGLOMERATING GASIFIER PROJECT – The Institute of Coal Chemistry, China (C-123)

The Institute of Coal Chemistry (ICC) of the Chinese Academy of Sciences is developing an ash agglomerating coal gasification process. The process is applicable to a wide range of coals including those with high ash content and high ash fusion temperature.

In 1983, a small scale pilot gasifier, or PDU, was set up. At first, different coals were gasified with air/steam as gasifying agents to make low heating value gas for industry. Later, coals were gasified with oxygen/steam to make synthetic gas for chemical synthesis. A pilot scale gasification system of 24 tons per day coal throughput was scheduled for startup in late 1990.

The gasifier is a cylindrical column of 0.3 meter inside diameter with a conical gas distributor and central jet tube on the bottom. The enlarged upper section is 0.45 meter inside diameter in order to settle out the gas-entrained coarse particles. The total height of the gasifier is about 7.5 meters.

Predried coal is blown into the gasifier after passing through the lockhopper and weighing system. Preheated air/steam (or oxygen/steam) enters the gasifier separately through a gas distributor and central jet tube. The coal particles are mixed with hot bed materials and decomposed to gas and char. Because of the central jet, there is a high temperature zone in the dense bed in which the ash is agglomerated into larger and heavier particles. The product gas passes through two cyclones in series to separate the entrained fine particles. Then the gas is scrubbed and collected particles are recycled into the gasifier through standpipes. The fines recycle and ash agglomeration make the process efficiency very high.

Based on the PDU data and cold model data, a 1 meter inside diameter gasifier system was designed and constructed. It is to be operated at atmospheric pressure to 0.5 MPa with a coal feed rate of 1 ton per hour.

CIGAS GASIFICATION PROCESS PROJECT – Fundacao de Ciencia e Tecnologia – CIENTEC (C-130)

The CIGAS Process for the generation of medium BTU gas is aimed at efficient technological alternatives suitable for Brazilian mineral coals of high ash content. No gasification techniques are known to be available and commercially tested for Brazilian coals.

The CIGAS Process research and development program has been planned for the interval from 1976 to 1998. In 1977 an atmospheric bench scale reactor was built, from which were obtained the first gasification data for Brazilian coals in a fluidized bed reactor. In 1978 a feasibility study was completed for the utilization of gas generated as industrial fuel. Next the first pressurized reactor in Latin America was built in bench scale, and the first results for pressurized coal gasification were obtained.

In 1979 the first atmospheric fluidized bed pilot scale unit was assembled (with a throughput of 7.2 tons per day of coal). In 1980 a project involving a pressurized unit for oxygen and steam began (20 atmospheres and 0.5 tons per day of coal). The plant was fully operational in 1982. In 1984 the pressurized plant capacity was enlarged to 2.5 tons per day of processed coal and at the same time air was replaced by oxygen in the atmospheric plant. This unit started processing 17 tons per day of coal.

In 1986 a unit was built to treat the liquid effluents generated throughout the process and studies on hot gas desulfurization were started in bench scale. By the end of 1988 pilot scale studies were finished. As the result of this stage, a conceptual design for a prototype unit will be made. This prototype plant will be operational in 1994 and in 1996 the basic project for the demonstration unit will be started. The demonstration unit is planned to be operational in 2001.

Project Cost: US$6.0 million up to the end of 1988. The next stage of development will require US$8 million.

CIVOGAS ATMOSPHERIC GASIFICATION PILOT PLANT – Fundacao de Ciencia e Tecnologia – CIENTEC (C-133)

The CIVOGAS process pilot plant is an atmospheric coal gasification plant with air and steam in a fluidized-bed reactor with a capacity of five gigajoules per hour of low-BTU gas. It was designed to process Brazilian coals at temperatures up to 1,000 degrees C. The pilot gasifier is about six meters high and 0.9 meters inner diameter. The bed height is usually 1.6 meters (maximum 2.0 meters).

The CIVOGAS pilot plant has been successfully operating for approximately 10,000 hours since mid 1984 and has been working mainly with subbituminous coals with ash content between 35 to 55 percent weight (moisture-free). Cold gas yields for both coals are typically 65 and 50 percent respectively with a carbon conversion rate of 68 and 60 weight percent respectively.

The best operating conditions to gasify low-rank coals in the fluidized bed have been found to be 1,000 degrees C, with the steam making up around 20 percent by weight of the air-steam mixture.

Two different coals have been processed in the plant. The results obtained with Leao coal are significantly better than those for Candida coal, the differences being mostly due to the relative contents of ash and moisture in the feedstock.

CIENTEC expects that in commercial plants or in larger gasifiers, better results will be obtained, regarding coal conversion rate and cold gas yield due to greater major residence time, and greater heat recovery from the hot raw gas.

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

According to the CIENTEC researchers, the fluidized-bed distributor and the bottom char withdrawal system have been their main concerns, and much progress has been made.

COALPLEX PROJECT – AECI (C-140)

The Coalplex Project is an operation of AECI Chlor-Alkali and Plastics, Ltd. The plant manufactures poly-vinyl chloride (PVC) and caustic soda from anthracite, lime, and salt. The plant is fully independent of imported oil. Because only a limited supply of ethylene was available from domestic sources, the carbide-acetylene process was selected. The plant has been operating since 1977.

The five processes include calcium carbide manufacture from coal and calcium oxide; acetylene production from calcium carbide and water; brine electrolysis to make chlorine, hydrogen, and caustic; conversion of acetylene and hydrogen chloride to vinyl chloride; and vinyl chloride polymerization to PVC. Of the five plants, the carbide, acetylene, and VCM plants represent the main differences between coal-based and conventional PVC technology.

Project Cost: Not disclosed

COGA-1 PROJECT – Coal Gasification, Inc. (C-iso)

The COGA-1 project has been under development since 1983. The proposed project in Macoupin County, Illinois will consume 1 million tons of coal per year and will produce 675,000 tons of urea ammonia and 840,000 tons of urea per year. It will use a high-temperature, high-pressure slagging gasification technology. When completed, the COGA-1 plant would be the largest facility of its kind in the world.

Sponsors were in the process of negotiations for loan guarantees and price supports from the United States Synthetic Fuels Corporation when the SFC was dismantled by Congressional action in late December 1985. On March 18, 1986 Illinois Governor James R. Thompson announced a $26 million state and local incentive package for COGA-1 in an attempt to move the $690 million project forward. The project sponsor is continuing with engineering and financing efforts.

Project Cost: $690 million

COLOMBIA COAL GASIFICATION PROJECT – Carbocol (C-lob)

The Colombian state coal company, Carbocol plans for a coal gasification plant in the town of Amaga in the mountainous inland department of Antioquia.

Japan Consulting Institute is working on a feasibility study on the gasification plant and current plans are to build a US$10 to 20 million pilot plant initially. This plant would produce what Carbocool calls "a clean gas fuel" for certain big industries in Antioquia involved in the manufacture of food products, ceramics and glass goods. According to recommendations in the Japanese study, this plant would be expanded in the 1990s to produce urea if financing is found.

Project Cost: $20 million initial
$200 million eventual

CORDERO COAL UPGRADING DEMONSTRATION PROJECT – Cordero Mining Company (C-170)

Cordero Mining Company will demonstrate the Carbontec Syncoal process at a plant to be built near its mine in Gillette, Wyoming. The demonstration will produce 250,000 tons per year of upgraded coal product from high-moisture, low-sulfur, low-rank coals.

The project was selected by the United States Department of Energy (DOE) in 1991 for a Clean Coal Technology Program award. DOE will fund 50 percent of the $34.3 million project cost. However, the cooperative agreement is still being negotiated.

The Syncoal process converts high-moisture subbituminous coal into a high-BTU, low-moisture product. Hot oil and flue gas serve to heat the coal and to keep it in an inert atmosphere during coal processing. The hot oil seals the surface against moisture as well as preventing surface degradation during handling.

It is expected that this upgraded coal product can be used by midwestern and eastern utilities that currently burn high-sulfur, high-rank coals to comply with stricter environmental regulations.

Project Cost: $34.3 million
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

CRE SPOUTED BED GASIFIER – British Coal, Otto-Simon Carves (C-190)

A spouted fluidized bed process for making low-BTU fuel gas from coal has been developed by British Coal at the Coal Research Establishment (CRE). A pilot plant has been built with a coal throughput of 12 tonnes per day.

This project was sponsored by the European Economic Community (EEC) under two separate demonstration grants. The results obtained established the basis of a simple yet flexible process for making a gaseous fuel low in sulfur, tar and dust.

The CRE gasification process is based on the use of a submerged spouted bed. A significant proportion of the fluidizing gas is introduced as a jet at the apex of a conical base. This promotes rapid recirculation within the bed enabling caking coals to be processed without agglomeration problems. Coals with swelling numbers up to 8.5 were processed successfully.

Plant construction was completed in April 1985 and cold commissioning of all aspects of the plant was successfully achieved by June 1985. As part of the contract with the EEC several extended trials were completed between April 1986 and March 1987 using char as bed material. Between April 1987 and November 1989, a further contract with the EEC investigated the use of inert bed materials and oxygen enrichment of the fluidizing air. This work enabled coal conversion efficiencies on the order of 90 percent (mass basis) to be attained, and allowed gases to be produced with caloric values up to 73 MJ/m³ (dry, gross).

Work on the 12 tonne per day pilot plant was directed towards providing design information for gasifiers operated at atmospheric pressure for industrial fuel gas applications. A range of commercial gasifiers with a coal throughput typically of 24 to 100 tonnes per day have been developed. To this end a license agreement was signed by OSC Process Engineering Ltd. (OSC) to exploit the technology for industrial application. Designs of commercial gasifiers are available and OSC together with British Coal are actively promoting the use of the technology.

Although OSC has yet to build the first commercial unit, interest has been shown from a large number of potential clients worldwide.

The application of the process for power generation is now being investigated. Various cycles incorporating a pressurized version of the spouted bed technology have been studied and power station efficiencies up to 47 percent (lower heating value basis) are predicted. A contract with the EEC to develop a pressurized version commenced in January 1989. A 12 tonne/day pilot plant capable of operating at pressures up to 20 bar has been constructed and commissioned at CRE. Commissioning of the plant was completed in June 1990 and extensive operation of the plant has been carried out since.

CRIEPI ENTRAINED FLOW GASIFIER PROJECT – Central Research Institute of Electric Power Industry (Japan), New Energy and Industrial Technology Development Organization (C-200)

Japan's CRIEPI (Central Research Institute of Electric Power Industry) has been engaged in research and development on gasification, hot gas cleanup, gas turbines, and their integration into an IGCC (Integrated Gasification Combined Cycle) system.

An air-blown pressurized two-stage entrained-flow gasifier (2.4 ton per day process development unit) adopting a dry coal feed system has been developed and successfully operated. This gasifier design will be employed as the prototype of the national 200 ton per day pilot plant. As of late 1991, the gasifier had been operated for 1,920 hours, and tested on 19 different coals.

Research and development on a 200 ton per day entrained-flow coal gasification pilot plant equipped with hot gas cleanup facility and gas turbine has been carried out extensively from 1986 and will be completed in 1993.

CRIEPI executed a feasibility study of entrained-flow coal gasification combined cycle, supported by the Ministry of International Trade and Industry (MITI) and New Energy Development Organization (NEDO). They evaluated eight systems combining different methods of coal feed (dry/slurry), oxidizer (air/oxygen) and gas cleanup methods (hot-gas/cold-gas). The optimal plant system, from the standpoint of thermal efficiency, was determined to be composed of dry coal feed, airblown and hot-gas cleanup methods. This is in contrast to the Cool Water demonstration plant, which is composed of coal slurry feed, oxygen-blown and hot-gas cleanup systems.

For the project to build a 200 ton per day entrained-flow coal gasification combined cycle pilot plant, the electric utilities have organized the "Engineering Research Association for Integrated Coal Gasification Combined Cycle Power Systems (IGC)" with 10 major electric power companies and CRIEPI to carry out this project supported by MITI and NEDO.

Basic design and engineering of the pilot plant was started in 1986 and manufacturing and construction started in 1988 at the Nakoso Coal Gasification Power Generation Pilot Plant site. Coal Gasification Tests began in June 1991 with the air blown pressurized entrained-flow gasifier. Tests will begin in 1992 for the hot gas clean-up system and a high temperature gas turbine of 1,260°C combustor outlet temperature.

Project Cost: 53 billion yen
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

DELAWARE CLEAN ENERGY PROJECT – Texaco Syngas Inc., Star Enterprise, Delmarva Power & Light, Mission Energy (C-208)

Texaco Syngas Inc., Star Enterprise, a partnership between Texaco and Saudi Refining, Inc., Delmarva Power and Light Co. and Mission Energy have begun joint engineering and environmental studies for an integrated gasification combined cycle (IGCC) electrical generating facility. The project calls for the expansion of an existing power plant adjacent to the Star Enterprise refinery in Delaware City, Delaware. The facility would convert over 2,000 tons per day of high sulfur petroleum coke, a byproduct of the Star refinery, into clean, gaseous fuel to be used to produce about 200 MW of electrical power in both existing and new power generating equipment.

Completion is planned for mid-1996 at an estimated cost of approximately $300 million (1990 dollars).

The project has the potential to reduce substantially overall emissions at the Delaware City facilities, more than double the current electric output and make use of the coke byproduct from the oil refinery. The Phase I studies will require approximately one year to complete (in 1991) at an estimated cost of $6 million.

The existing power plant would be upgraded and expanded and would continue to operate as a cogeneration facility.

Project Cost: $250 - 300 million (1989 dollars)

DESTEC SYNGAS PROJECT – Louisiana Gasification Technology, Inc. a subsidiary of Destec Energy, Inc. (C-210)

The Destec Syngas Project, located in Plaquemine, Louisiana, began commercial operations in April, 1987, operating at rates up to 105 percent of capacity. As of February 1992 the project has completed 22,043 hours on coal. It has produced 24,218 billion BTU of on-spec syngas and has reached 1,837,275 tons of coal processed. A 90-day consecutive production record of 71.2 percent capacity was reached in October 1990. A 30-day consecutive production record of 99 percent availability and 89 percent capacity factor was reached in February 1992.

At full capacity, the plant consumes 2,400 tons of coal per day providing 30 billion BTU per day of medium BTU gas. The process uses Dow-developed coal gasification technology to convert coal or lignite into medium BTU synthetic gas.

The process uses a pressurized, entrained flow, slagging, slurry-fed gasifier with a continuous slag removal system. Dow's GAS/SPEC ST-1 acid gas removal system and Unocal's Selectox sulfur conversion unit are also used. Oxygen is supplied by Air Products.

Construction of the plant was completed in 1987 by Dow Engineering Company. Each gasification module is sized to produce syngas to power 150-200 megawatt combustion turbines. The project is owned and operated by Louisiana Gasification Technology Incorporated, a wholly owned subsidiary of Houston-based Destec Energy, Inc., a subsidiary of The Dow Chemical Company.

In this application, the Destec Syngas Process and the associated process units have been optimized for the production of synthetic gas for use as a combustion gas turbine fuel. The project received a price guarantee from the United States Synthetic Fuels Corporation (now the Treasury Department) which is subject to the amount of gas produced by the project. The amount of the price guarantee is based on the market price of the natural gas and the production of the project. Maximum amount of the guarantee is $620 million.

Project Cost: $72.8 million

DUNN NOKOTA METHANOL PROJECT – The Nokota Company (C-215)

The Nokota Company is the sponsor of the Dunn-Nokota Methanol Project, Dunn County, North Dakota. Nokota plans to convert a portion of its coal reserves in Dunn County, via coal gasification, into methanol and other marketable products, including carbon dioxide for enhanced oil recovery in the Williston and Powder River Basins. $20 million has been spent, and 12 years have been invested in site and feasibility studies. After thorough public and regulatory review by the state of North Dakota, air quality and conditional water use permits have been approved. The Bureau of Reclamation released the final Environmental Statement on February 26, 1988.

In terms of the value of the products produced, the Dunn-Nokota project is equivalent to an 800 million barrel proven oil reserve. In addition, the carbon dioxide product from the plant can be used to recover substantially more crude oil from oil fields in North Dakota, Montana, and Wyoming through carbon dioxide injection and crude oil displacement.

The Dunn-Nokota plant is designed to use the best available environmental control technology. At full capacity, the plant will use the coal under approximately 390 acres of land (about 14.7 million tons) each year. Under North Dakota law, this land is required to be reclaimed and returned to equal or better productivity following mining. Nokota plans to work closely with local community leaders, informing them of the types and timing of socioeconomic impact associated with this project.
Dunn-Nokota would produce approximately 81,000 barrels of chemical grade methanol, 2,400 barrels of gasoline blending stock (naphtha) and 300 million standard cubic feet of pipeline quality, compressed carbon dioxide per day from 40,000 tons of lignite (Beulah-Zap bed).

Additional market studies will determine if methanol production will be reduced and gasoline or substitute natural gas coproduced.

Existing product pipelines and rail facilities are available to provide access to eastern markets for the project's output. Access to western markets for methanol through a new dedicated pipeline to Bellingham, Washington, is also feasible if West Coast market demand warrants.

Construction employment during the six year construction period will average approximately 3,200 jobs per year. When complete and in commercial operation, employment would be about 1,600 personnel at the plant and 500 personnel in the adjacent coal mine.

Nokota's schedule for the project is subject to receipt of all permits, approvals, and certifications required from federal, state, and local authorities and upon appropriate market conditions for methanol and other products from the proposed facility.

Project Cost:
- $2.6 billion (Phase I and II)
- $0.2 billion (CO2 compression)
- $0.1 billion (Pipeline interconnection)
- $0.4 billion (Mine)

ELSAM GASIFICATION COMBINED CYCLE PROJECT – Elsam (C-218)

Elsam, the Danish utility for the western part of Denmark, in January 1991 submitted a proposal for the construction of a 315-megawatt integrated gasification combined cycle (IGCC) power plant using the PRENFLO gasification technology. The utility proposes a 3-year test period under the Thermie program of the European Communities.

The IGCC plant would be built as a joint project of the German Utility PreussenElektra and the Danish utility Sonderjyllands Hojspaendingsvaerk.

Commissioning is planned for 1995.

ENCOAL LFC DEMONSTRATION PLANT – ENCOAL Corporation, United States Department of Energy (C-221)

ENCOAL Corporation, a wholly owned subsidiary of Shell Mining Company of Houston, Texas, received funding from the Department of Energy's Clean Coal Technology Round 3 Program for a 1,000 ton per day mild gasification plant at Shell's Buckskin Mine in Northeastern Wyoming. The government will fund 50 percent of the proposed $72.6 million total cost. The demonstration plant will utilize the LFC technology developed by SGI International.

The demonstration plant will be put in service in the second quarter of 1992. The plant is designed to be operated as a small commercial facility and is expected to produce sufficient quantities of process derived fuel and coal derived liquids to conduct full scale test burns of the products in industrial and utility boilers. Feed coal for the plant will be purchased from the Buckskin Mine which is owned and operated by Triton Coal Company (a wholly owned subsidiary of Shell Mining Company). Other United States coals may be shipped to the demonstration plant from time to time for test processing, since the process appears to work well on lignites and some Eastern bituminous coals.

A Permit to Construct was received from the Wyoming Department of Environmental Quality, Air Quality Division for the demonstration plant. It was approved on the basis of the use of best available technology for the control of SO2, NOx, CO, hydrocarbons and particulates. There will be no waste water and source water requirements will be very small.

Ground was broken at the Buckskin mine site for the commercial process demonstration unit in late 1990. Work continued through the winter with the foundations being in place by early 1991. Construction activities are ahead of schedule with construction of all silos and the coal pyrolyzer complete, mine expansion tasks complete, all major equipment in place, and steel erection 80 percent complete. The plant is expected to be delivering products by mid-1992. The plant will process 1,000 tons of coal per day and produce 150,000 barrels of liquids per year plus 180,000 tons of upgraded solid fuel.

Engineering, procurement and construction services are being provided by the M.W. Kellogg Company. SGI International will furnish technical services.

Estimated Project Cost: $72.6 million
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

FREETOWN IGCC PROJECT – Texaco Syngas Inc., Commonwealth Energy and General Electric Company (C-223)

The three companies have begun joint development of an electrical generating facility, using an integrated gasification combined cycle (IGCC) design, in Freetown, Massachusetts. The facility would be known as the Freetown Energy Park.

The energy park will be located on a 600 acre site along the Taunton River owned by a subsidiary of Commonwealth Energy.

Texaco Syngas will design the plant to use the Texaco Coal Gasification process and General Electric’s high efficiency, gas turbines. The initial phase will produce 440 megawatts of power to be sold to New England utilities and gasify roughly 4,000 tons of coal per day.

The plant will be one of the world's cleanest coal based power plants with emissions levels of particulates, $SO_x$ and $NO_x$ significantly less than conventional coal plants and below state and federal emissions standards.

The gasification process involves the injection of a coal-water slurry with oxygen into a pressurized vessel where partial oxidation of the coal occurs and synthesis gas is produced. The gas leaves the vessel through a water bath where ash and particulates are removed as slag. The cleaned gas is then directed to a sulfur removal system, which removes 98 percent of the sulfur prior to its use within the gas turbine.

Using the syngas, the gas turbine produces electricity while exhausting high temperature exhaust gas to heat recovery steam generators. The heat recovery steam generators produce steam for use in a steam turbine which in turn produces additional electricity.

Project startup is scheduled for late 1995.

FRONTIER ENERGY COPROCESSING PROJECT – Canadian Energy Developments, Kilbom International (C-225)

Under the United States Department of Energy's Clean Coal Technology Round 3 Program, the Frontier Energy project received funding for the commercial demonstration of a state-of-the-art technology for the simultaneous conversion of high sulfur coal and heavy oil (bitumen) to low sulfur, lean burning, liquid hydrocarbon fuels plus the cogeneration of electricity for export. Two main liquid hydrocarbon products are produced, a naphtha fraction which can be used as a high value petrochemical feedstock or can be processed further into high octane motor fuel and low sulfur fuel oil that can be used to replace high sulfur coal in thermal power plants. Cogenerated electricity, surplus to the requirements of the demonstration plant, is exported to the utility electrical system.

Frontier Energy is a venture involving Canadian Energy Developments of Edmonton, Alberta, Canada and Kilbom International Ltd. of Tucson, Arizona.

The technology being demonstrated is the CCLC Coprocessing technology in which a slurry of coal and heavy oil are simultaneously hydrogenated at moderate severity conditions (temperature, pressure, residence time) to yield a low boiling range ($C_{7-97}$ degrees F) distillate product.

The CCLC Coprocessing technology is being developed by Canadian Energy Developments Inc. in association with the Alberta Office of Coal Research and Technology (AOCRT) and Gesellschaft fur Kohleverfiussigung GmbH (GfK) of Saarbrucken, West Germany.

Two integrated and computerized process development units (PDUs), 18-22 pounds per hour feed rate, are currently being operated to confirm the technology in long duration runs, to generate operating data for the design of larger scale facilities and to produce sufficient quantities of clean distillate product for secondary hydrotreating studies and market assessment studies.

Canadian Energy and GfK are planning to modify an existing 10 ton/day coal hydrogenation pilot plant to the CCLC Coprocessing configuration and to use it to confirm the coprocessing technology in large pilot scale facilities while feeding North American coals and heavy oils. Data from this large pilot scale facility will form the basis of the design specification for the Frontier Energy Demonstration Project.

The demonstration project will process 1,128 tons per day of Ohio No. 6 coal and 20,000 barrels per day of Alberta heavy oil. An unsuccessful application was made for Clean Coal Technology (CCT) funds in Round III. The project intends to file an application for CCT funds in Round V.

GE HOT GAS DESULFURIZATION – GE Environmental Services Inc. and Morgantown Energy Technology Center (C-228)

This project was designed to demonstrate the operation of regenerable metal oxide hot gas desulfurization and particulate removal system integrated with the GE air blown, coal gasifier at the GE Corporate Research and Development Center in Schenectady, New York.
Construction of the demonstration facility was completed by 1990 and several short duration runs were done to allow a long duration (100 hour) run to be completed in 1991. The facility gasifies 1700 pounds per hour of coal at 280 psig. Outlet gas temperature ranges from 830-1150°F.

During a 4.5 hour period in a 60 hour run the hot gas cleanup system achieved an overall sulfur removal of 95.5%.

**GERMAN IGCC POWERPLANT – Stadtwerke Duisburg** (C-229)

The project for Stadtwerke Duisburg in Germany is based on the 1,200 TPD PRENFLO gasifier and two Siemens V64 gas turbines.

A detailed site-specific study was performed together with Siemens/KWU and Linde. Capacity was approximately 170 MWe. After the decision by the European Commission in favor of the Puertollano Project in Spain, the management of Stadtwerke Duisburg decided to stop all activities.

**GFK DIRECT LIQUEFACTION PROJECT – West German Federal Ministry for Research and Technology, Saarbergwerke AG, and GfK Gesellschaft für Kohleverflüssigung MbH** (C-230)

For the hydrogenation of heavy oils, mixtures of heavy oil and coal (Co-processing) and coals with low ash contents, GfK favors a unique hydrogenation reactor concept in which the feedstock is fed at the top and passes through the reactor counter-currently to the hydrogen which is fed at the reactor bottom. It has been found that this reactor is superior to the classical bubble column. At present this concept is being further tested using a variety of different coals and residual oils on the bench scale.

On the 31st of December 1989, GFK terminated the operation of its pilot and bench-scale facilities. The further development, particularly the demonstration of the counter-flow-reactor on the pilot scale, is now pursued within a cooperation with East Germany's company Maschinen und Anlagenbau Grimma GmbH where an existing hydrogenation pilot-plant is presently being modified to the new concept. Operation began at the end of 1991.

Project Cost: Not disclosed

**GREAT PLAINS SYNTHFUELS PLANT – Dakota Gasification Company** (C-240)

Initial design work on a coal gasification plant located near Beulah in Mercer County, North Dakota commenced in 1973. In 1975, ANG Coal Gasification Company (a subsidiary of American Natural Resources Company) was formed to construct and operate the facility and the first of many applications were filed with the Federal Power Commission (now FERC). The original plans called for a plant designed to produce 250 million cubic feet per day to be constructed by late 1981. However, problems in financing the plant delayed the project and in 1976 the plant design was reduced to 125 million cubic feet per day. A partnership named Great Plains Gasification Associates was formed by affiliates of American Natural Resources, Peoples Gas (now MidCon Corporation) Tenneco Inc., Transco Companies Inc. (now Transco Energy Company) and Columbia Gas Systems, Inc. Under the terms of the partnership agreement, Great Plains would own the facilities, ANG would act as project administrator, and the pipeline affiliates of the partners would purchase the gas.

In January 1980, FERC issued an order approving the project. However, the United States Court of Appeals overturned the FERC decision. In January 1981, the project was restructured as a non-jurisdictional project with the synthetic natural gas (SNG) sold on an unregulated basis. In April 1981, an agreement was reached whereby the SNG would be sold under a formula that would escalate quarterly according to increases in the Producer Price Index with a cap equal to the energy-equivalent price of No. 2 Fuel Oil. During these negotiations, Columbia Gas withdrew from the project. On May 13, 1982, it was announced that a subsidiary of Pacific Lighting Corporation had acquired a 10 percent interest in the partnership; 7.5 percent from ANR's interest and 2.5 percent from Transco.

Full scale construction did not commence until August 6, 1981 when the United States Department of Energy (DOE) announced the approval of a $2.02 billion conditional commitment to guarantee loans for the project. This commitment was sufficient to cover the debt portion of the gasification plant, Great Plains' share of the coal mine associated with the plant, an SNG pipeline to connect the plant to the interstate natural gas system, and a contingency for overruns. Final approval of the loan guarantee was received on January 29, 1982. The project sponsors were generally committed to providing one dollar of funding for each three dollars received under the loan guarantee up to a maximum of $740 million of equity funds.

The project was designed to produce an average of 125 million cubic feet per day (based on a 91 percent onstream factor, i.e., a 137.3 million cubic foot per day design capacity) of high BTU pipeline quality SNG, 93 tons per day of ammonia, 88 tons per day of sulfur, 200 million cubic feet per day of carbon dioxide, potentially for enhanced oil recovery, and other miscellaneous by-products including tar oil, phenols, and naphtha to be used as fuels. Approximately 16,000 tons per day of North Dakota lignite were expected to be required as feedstock.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

In August, 1985 the sponsors withdrew from the project and defaulted on the loan, and DOE began operating the plant under a contract with the ANG Coal Gasification Company. The plant successfully operated throughout this period and earned revenues in excess of operating costs. The SNG is marketed through a 34 mile long pipeline connecting the plant with the Northern Border pipeline running into the eastern United States.

In parallel with the above events, DOE and the Department of Justice (DOJ) filed suit in the District Court of North Dakota (Southwestern Division) seeking validation of the gas purchase agreements and approval to proceed with foreclosure. On January 14, 1986 the North Dakota Court found the gas purchase agreements valid, that state law was not applicable and that plaintiffs (DOE/DOJ) were entitled to a summary judgment for foreclosure. A foreclosure sale was held and DOE obtained legal title to the plant and its assets on July 16, 1986. This decision was upheld by the United States Court of Appeals for the Eighth Circuit on January 14, 1987. On November 3, 1987, the Supreme Court denied a petition for a writ of certiorari.

The North Dakota District Court also held that the defendant pipeline companies were liable to the plaintiffs (DOE/DOJ) for the difference between the contract price and the market value price. This decision was upheld by the United States Court of Appeals for the Eighth Circuit on May 19, 1987. No further opportunity for appeal exists and the decisions of the lower court stands.

In early 1987 the Department of Energy hired Shearson Lehman Bros. to help sell the Great Plains plant. In August, 1988 it was announced the Basin Electric Power Cooperative had submitted the winning bid for approximately $85 million up-front plus future profit-sharing with the government. Two new Basin subsidiaries, Dakota Gasification Company (DGC) and Dakota Coal Company, operate the plant and manage the mine respectively. Ownership of the plant was transferred on October 31, 1988.

Under Dakota Gasification ownership, the plant has produced SNG at over 108 percent of design capacity.

In 1989 DGC began concentrating on developing revenue from byproducts. On February 15, 1991, a phenol recovery facility was completed. This project will produce 35 million pounds of phenol annually, providing manufacturers an ingredient for plywood and chipboard resins. The first railcar of phenol was shipped in January 1991. DGC has signed contracts with three firms to sell all of its output of crude cresylic acids, which it produces from its phenol recovery project.

Construction of a facility to extract krypton/xenon from the synfuel plant's oxygen plant was completed in March 1991. Rare gases are to be marketed to the lighting industry starting in early 1991. DGC signed a 15-year agreement in 1989 with the Linde Division of Union Carbide Industrial Gases Inc. to sell all of the plant's production of the krypton/xenon mixture. The first shipment of the product occurred on March 15, 1991. Other byproducts being sold from the plant include anhydrous ammonia, sulfur and liquid nitrogen. Argon, carbon dioxide, naphtha and cresote are also potential byproducts.

In late 1990 DGC filed with the North Dakota State Health Department a revision to the applications to amend the Air Pollution Control Permit to Construct. The revised application defines the best available control technology to lower SO₂ emissions at the plant.

In late 1990, DGC and DOE initiated a lawsuit against the four pipeline company purchasers contracted to buy SNG. At the same time, these four pipeline companies filed separate arbitration proceedings. The issues in all of these proceedings involve: the extent of the pipeline firms' obligations to take and provide transportation for SNG; whether the sales price of SNG has been understated; and whether there should have been a 1987 adjustment to the rate the plant charges the pipeline companies to transport their SNG to a point of interconnection on the Northern Border Pipeline system.

Project Cost: $2.1 billion overall

HOT GAS CLEANUP PROCESS – Southern Company Services, Inc. and United States Department of Energy (C-257)

Southern Company Services, Inc. (SCS) Birmingham, Alabama in 1990 began a five-year, $46 million effort to develop advanced gas cleaning systems that could be the final link between advanced coal-fired power generating concepts and the commercial marketplace.

Southern Company will build and operate a state-of-the-art test facility at Alabama Power Company's Wilsonville plant. When complete, this facility will be able to test innovative techniques for cleaning the gas produced by two advanced coal technologies—pressurized fluidized bed combustion and gasification combined cycle systems.

The new test facility at Wilsonville will move the hot gas cleanup techniques from laboratory research to integrated engineering tests. Actual gases from coal gasification or combustion will be used.

SCS has a cooperative agreement with DOE to construct and operate a nominal 50 ton per day coal feed facility for long-term testing of hot gas cleanup. The test facility will be designed to operate in either a gasification or a pressurized fluidized bed combustion (PFBC) mode with gas temperatures up to 1,800°F and a system pressure of 300 psig. The gas generator will be designed to operate with an Eastern bituminous coal and an alternate Powder River subbituminous coal. Researchers will be able to evaluate the performance of the cleanup devices while varying gas temperatures, gas pressures, particulate levels, particulate sizes and types of coal.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

Design and construction of the test facility will take three years. Phase 1 of the project is the conceptual design which was initiated January 1, 1991. The detailed design in Phase 2 is expected to be completed by the fall of 1992. Construction of the facility is anticipated to last 15 months, with operations targeted to begin by January 1994. A nominal two years of testing are provided for in the cooperative agreement. Southern Company Services and M. W. Kellogg of Houston, Texas will design the facility, which will be built by Alabama Power Company and operated by Southern Electric International Inc. The Southern Research Institute will oversee the evaluation of the cleanup systems.

DOE is providing $36.8 million, or 80 percent of the contract's total cost. Southern Company Services, with support from the M. W. Kellogg Company and the Electric Power Research Institute, is providing the remaining $9.2 million.

DOE is currently sponsoring two other coal research efforts at the Wilsonville plant, a test facility for coal liquefaction technology and a unit that cleans coal before it is used.

Project Cost: $46 million

HUMBOLT ENERGY CENTER PROJECT – Continental Energy Associates and Pennsylvania Energy Development Authority (C-265)

Greater Hazleton Community Area New Development Organization, Inc. (CAN DO, Incorporated) built a facility in Hazle Township, Pennsylvania to produce low BTU gas from anthracite. Under the third general solicitation, CAN DO requested price and loan guarantees from the United States Synthetic Fuels Corporation (SFC) to enhance the facility. However, the SFC turned down the request, and the Department of Energy stopped support on April 30, 1983. The plant was shut down and CAN DO solicited for private investors to take over the facility.

The facility has been converted into a 135 megawatt anthracite refuse-fueled integrated gasification combined cycle cogeneration plant. Gas produced from anthracite coal in both the original facility and in new gasifiers is being used to fuel turbines to produce electricity. One hundred megawatts of power will be purchased by the Pennsylvania Power & Light Company over a 20-year period. Steam is also produced which is available to industries within Humboldt Industrial Park at a cost well below the cost of in-house steam production.

The project cost for this expansion is over $100 million. The Pennsylvania Energy Development Authority authorized the bond placement by the Northeastern Bank of Pennsylvania and the Swiss Bank.

Project Cost: over $100 million

HYCOL HYDROGEN FROM COAL PILOT PLANT – Research Association for Hydrogen from Coal Process Development (Japan) (C-270)

In Japan, the New Energy and Industrial Technology Development Organization (NEDO) has promoted coal gasification technologies based on the fluidized bed. These include the HYBRID process for high-BTU gas making and the low-BTU gas making process for integrated combined cycle power generation. NEDO has also started to develop coal gasification technology based on a multipurpose coal gasifier for medium-BTU gas.

The multipurpose gasifier was evaluated as a key technology for hydrogen production, since hydrogen is the most valuable among coal gasification products. NEDO decided to start the coal-based hydrogen production program at a pilot plant beginning in fiscal year 1986. Construction of the pilot plant in Sodegaura, Chiba was completed in August, 1990. Operational research was to begin in 1991 after a trial run.

The key technology of this gasification process is a two-stage spiral flow system. In this system, coal travels along with the spiral flow from the upper part towards the bottom because the four burner nozzles of each stage are equipped in a tangential direction to each other and generate a downward spiral flow. As a result of this spiral flow, coal can stay for a longer period of time in the chamber and be more completely gasified.

In order to obtain a higher gasification efficiency, it is necessary to optimize the oxygen/coal ratio provided to each burner. That is, the upper stage burners produce reactive char and the lower stage burners generate high temperature gas. High temperature gas keeps the bottom of the gasifier at high temperature, so molten slag falls fluently.

The specifications of the pilot plant are as follows:

- Coal feed: 50 ton per day
- Pressure: 30 kg/cm²
- Temperature: about 1,800°C
- Oxidant: Oxygen
- Coal Feed: Dry

SYNTHETIC FUELS REPORT, JUNE 1992
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

- Slag Discharge  Slag Lock Hopper
- Refractory Lining  Water-cooled slag coating
- Dimensions Outer Pressure Vessel 2 Meters Diameter, 13.5 Meters Height
- Carbon Conversion  98 Percent
- Cold Gas Efficiency  78 Percent
- 1,000 Hours Continuous Operation

The execution of this project is being carried out by the Research Association for Hydrogen from Coal Process Development, a joint undertaking by nine private companies, and is organized by NEDO. Additional research is also being conducted by several private companies to support research and development at the pilot plant. The nine member companies are:

Idemitsu Kosan Co., Ltd.
Osaka Gas Co., Ltd.
Electric Power Development Company
Tokyo Gas Co., Ltd.
Toho Gas Co., Ltd.
Nippon Mining Company
The Japan Steel Works, Ltd.
Hitachi, Ltd.
Mitsui SRC Development Co., Ltd.

IGT MILD GASIFICATION PROJECT – Institute of Gas Technology (IGT), Kerr-McGee Coal Corporation, Illinois Coal Development Board (C-272)

Kerr-McGee Coal Corporation is heading a team whose goal is to develop the Institute of Gas Technology's (IGT) MILDGAS advanced mild gasification concept to produce solid and liquid products from coal. The process uses a combined fluidized-bed/entrained-bed reactor designed to handle Eastern caking and Western noncaking coals.

The 24 ton per day facility will be built at the Illinois Coal Development Park near Carterville, Illinois. The 3-year program will provide data for scaleup production of coproducts, preparation of a detailed design for a larger demonstration unit, and the development of commercialization plans.

Kerr-McGee Coal Corporation will provide the coal and oversee the project. Bechtel Corporation will design and construct the process development unit, and Southern Illinois University at Carbondale will operate the facility. IGT will supply the technology expertise and the activities of the team members.

The technology will produce a solid char that can be further processed into form coke to be used in blast furnaces as a substitute for traditional coke. Liquids produced by the process could be upgraded to make gasoline or diesel fuel or used to manufacture such materials as roofing and road binders, electrode binders, and various chemicals.

IMHEX MOLTEN CARBONATE FUEL CELL DEMONSTRATION – M-C Power Corporation, Combustion Engineering, Inc., Institute of Gas Technology (C-273)

Despite being turned down for funding under the United States Department of Energy's Clean Coal Technology Round 3 Program, M-C Power Corporation is going ahead with a demonstration project to repower an existing coal-fired power plant with coal gas-fueled IMHEX molten carbonate fuel cells (MCFC). The proposed coal gasification/MCFC system can be used to fully or partially repower existing power plants regardless of the fossil fuel for which they were initially designed. This repowering should result in more economic plants, with greater capacity and reduced emissions of SO₂ and NOₓ, says M-C Power.

The IMHEX configuration is a novel advanced molten carbonate fuel cell designed to eliminate many of the pumping problems experienced by previous molten carbonate fuel cell concepts.

The demonstration facility would be located at the Institute of Gas Technology's (IGT) Energy Development Center in Chicago, Illinois. The demonstration will use IGT's existing U-GAS coal gasifier and will produce 500 kilowatts of electricity.

The demonstration project was scheduled to begin April 1, 1991 and will be completed September 30, 1994. Total estimated cost of the project is $22,700,000.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

ISCOR MELTER-GASIFIER PROCESS – ISCOR, Voest-Alpine Industrieanlagenbau (C-275)

An alternative steel process that does not use coke has been commercialized at ISCOR’s Pretoria works (South Africa). Designed and built by Voest-Alpine Industrieanlagenbau GmbH (Linz, Austria), the plant converts iron ore and coal directly into 300,000 tons per year of pig iron in a melter-gasifier, referred to as the COREX process. Conventional techniques require use of a coke oven to make coke, which is then reacted with iron ore in a blast furnace. Production costs at the Pretoria plant are said to be 30 percent lower than conventional method costs.

Startup of the plant was in November 1989. Two separate streams of materials are gravity fed into the melter-gasifier. One stream is coal (0.5-0.7 tons of carbon per ton of pig iron produced) with ash, water and sulfur contents of up to 20 percent, 12 percent and 1.5 percent, respectively. Lime is fed together with the coal to absorb sulfur. The second stream—iron ore in lump, sinter or pellet form—is first fed to a reduction furnace at 850-900 degrees C and contacted with reducing gas (65-70 percent CO and 20-25 percent H₂) from the melter-gasifier. This step reduces the ore to 95 percent metal sponge iron. The metallization degree of the sponge iron where it comes into contact with the 850-900 degree C hot reducing gas produced in the reduction furnace, is 95% on average.

The sponge iron proceeds to final reduction and melting in the melter-gasifier, where temperatures range from 1,100 degrees C near the top of the unit to 1,500-1,700 degrees C at the oxygen inlets near the bottom. Molten metal and slag are tapped from the bottom. As a byproduct of the hot metal production export gas is obtained, which is a high quality gas with a caloric value of approximately 2000 kcal/Nm³. Voest-Alpine says the pig iron quality matches that from blast furnaces, and that costs were $150 per ton in 1990.

Voest-Alpine has also recently patented several schemes involving a fluidized bed meltdown-gasifier (United States Patents 4,725,308, 4,728,360, 4,729,786, issued in 1988). Typically a fluidized bed of coke particles is maintained on top of the molten iron bath by blowing in oxygen-containing gas just at the surface of the molten metal.

Voest-Alpine has been collaborating with Geneva Steel to demonstrate the technology in the United States, however, Geneva has shelved further action on the project after failing to receive funding in the DOE Clean Coal Technology Round 3. In 1990 Virginia Iron Industries Corporation announced plans to build a COREX plant in Hampton Roads, Virginia. (See Virginia Iron Corex Project C-613).

The COREX process is being marketed as an environmentally superior method of iron making and claims significant reductions in dust, SO₂ and NOₓ emissions compared to conventional methods.

During 1990 the plant ran at 100% design capacity.

K-FUEL COMMERCIAL FACILITY – K-Fuel Partnership (C-290)

The K-Fuel process was invented by Edward Koppelman and developed further by SRI International between 1976 and 1984. In 1984, K-Fuel Partnership (KFP) was formed to commercialize the process. KFP owns the worldwide patents and international licensing rights to the process in the United States and 37 foreign countries. In the K-Fuel process, low-grade coal or peat is dried and mildly pyrolyzed in two coupled reactors that operate at elevated temperatures and at a pressure of 800 psi. The process produces a pelletized, low-moisture, low-sulfur coal with a BTU value of 12,000, and by-product water and fuel gas. K-Fuel pellets contain 60 percent more energy (approximately 27 million BTU per ton) and 40 percent less sulfur than the raw coal. The fuel gas from the process is utilized on site to provide the needed heat for the process. K-Fuel was tested at Wisconsin Power and Light’s (WPL) Rock River generating station near Beloit in south-central Wisconsin. The test was successful and Wisconsin Power has agreed to buy up to one million tons per year.

KFP, headquartered in Denver, Colorado, owns and operates a full demonstration facility and research center at the Fort Union Coal Mine near Gillette, Wyoming. The laboratory and pilot facility, which can produce 25 tons of K-Fuel per day, has been in operation since July 1988.

Wisconsin Power and Light plans to use K-Fuel at several of its facilities to meet new state and federal emission control requirements. The upgraded coal is also less expensive to ship and store due to its improved heating value.

WPL, through its wholly owned subsidiary called ENSERV Inc., has purchased an interest in the K-Fuel technology. A license for the use of the K-Fuel technology on coal only in North America was issued to Heartland Fuels Corporation (HFC), and ENSERV subsidiary. HFC made application for funding to DOE under Round 4 of the Clean Coal Technology program but did not receive support. HFC has since reached an agreement to merge its project with the ThermoChem project, which did receive DOE support, and expects to announce the beginning of construction soon.

Project Cost: $62 Million
RWE Energie AG, a sister company of Rheinbraun AG, has decided to build a combined-cycle power station with integrated gasification based on the High Temperature Winkler (HTW) technology. Raw brown coal with 50 to 60 percent moisture will be dried down to 12 percent, gasified and dedusted with ceramic filters after passing the waste heat boiler. After the conventional scrubber unit, the gas will be desulfurized and fed to the combined cycle process with an unfired heat recovery steam generator. This project is referred to as KOBRA (in German: Kombikraftwerk mit Braunkohlenvergasung, i.e. combined-cycle power station with integrated brown coal gasification).

The capacity of the KOBRA plant will slightly exceed 300 MWe. The question of whether oxygen or air will be used as gasifying agent has not yet been decided, but irrespective of this the fuel gas will be produced in this demonstration plant by two gasifiers, each having a throughput of 1,800 tons per day of dried lignite. The gas turbine will have a rated capacity of about 200 MWe, and the overall plant is expected to reach a net efficiency of 46 percent.

Beginning of construction is scheduled for 1993 and start up in 1995. The most important orders awarded so far were placed with the MAN company as the general contractor, the Uhde/Lurgi consortium for the engineering of the coal gasification system, and the Siemens company for the delivery of the gas turbine (type 94.3). To implement this project, a task force comprising staff members of both RWE Energie AG and Rheinbraun AG started working in early 1990. To ensure that the plant can be constructed on schedule as from early 1993 and commissioned in late 1995, the orders relating to the desulfurization unit, the coal drying unit and some other large components were placed in 1990. Completion of the permit engineering is scheduled for mid-1992, so that building and operating permits can be applied for.

Of crucial importance for reaching a high overall efficiency is the coal drying system which reduces the moisture content of the raw brown coal to 12 percent. For this step, Rheinbraun's WTA process will be employed (WTA means fluidized-bed drying with internal waste heat utilization).

To demonstrate the technology, a plant having a capacity of 20 tons per hour of dried lignite will be started up in 1992 for testing purposes. Engineering of this project is being handled by Lurgi GmbH.

A successful test operation of the demonstration plant will provide the essential basis for the construction of commercial-scale power stations of this type. The start-up of a 600 MWe commercial-scale IGCC plant is scheduled for the turn of the century. This new generation of power stations will be characterized by a high overall efficiency, extremely low emissions, and low production costs.

### LAKESIDE REPOWERING GASIFICATION PROJECT – Combustion Engineering, Inc. and United States Department of Energy (DOE) (C-320)

The project will demonstrate Combustion Engineering's pressurized, airblown, entrained-flow coal gasification repowering technology on a commercial scale. The syngas will be cleaned of sulfur and particulates and then combusted in a gas turbine (40 MWe) from which heat will be recovered in a heat recovery steam generator (HRSG). Steam from the gasification process and the HRSG will be used to power an existing steam turbine (25 MWe).

The project is selected for demonstration at the Lakeside Generating Station of City Water, Light and Power, Springfield, Illinois. The selected site with associated characteristics and costs includes repowering an existing steam turbine to produce 65 MWe via the combined cycle mode.

The $270.7 million project will span 10 years, including 5 years needed to test and operate the system. The plant will continue to provide power to the city as part of its commercial grid during the testing period.

Design work for the new integrated power plant began in November 1990. The preliminary design package and plant cost estimates are complete. Gasifier groundbreaking is scheduled for September 1993, with initial coal-fired operation scheduled for mid-1995. Cold flow modeling of the gasifier internals and dry coal feed system continues.

DOE is providing $129.4 million, or 48 percent, of the project's total cost. The remaining funds will be provided by Combustion Engineering, City Water, Light & Power, and the Illinois Department of Energy and Natural Resources.

Project Cost: $270.7 million

### LAPORTE ALTERNATIVE FUELS DEVELOPMENT PROGRAM – Air Products & Chemicals, Inc., Electric Power Research Institute, and United States Department of Energy (DOE) (C-330)

Air Products and Chemicals, Inc. is proposing a 36-month program to develop technologies for the conversion of coal-derived synthesis gas to oxygenated hydrocarbon fuels, fuel intermediates, and octane enhancers, and to demonstrate the most promising technologies in DOE's Slurry Phase Alternative Fuels Development Unit (AFDU) at LaPorte, Texas. With emphasis on slurry phase
processing, the program will initially draw on the experiences of the successful Liquid Phase Methanol (LPMEOH) program. See completed project "LaPorte Liquid Phase Methanol Synthesis" in December 1991 Synthesis Fuels Report for details on the LPMEOH project.

Air Products has been conducting laboratory investigations into the synthesis of dimethyl ether (DME) since 1985 in an effort to improve syngas.

The alternative fuels development program aims to continue the investigations initiated in the above research program, with the principal objective being demonstration of attractive fuel technologies in the LaPorte AFUD. The focus is continued in pilot plant operations after a 12-18 month period of plant modifications. Certain process concepts such as steam injection, and providing H2 via in situ water-gas shift, will assist in higher conversions of feedstocks which are necessary, particularly for higher alcohol synthesis.

Four operating campaigns are currently envisaged. The first will focus on increased syngas conversion to methanol using steam injection and staged operation. The second will demonstrate production of dimethyl ether/methanol mixtures to (1) give optimum syngas conversion to storable liquid fuels, (2) produce mixtures for both stationary and mobile fuel applications, and (3) produce the maximum amount of DME, which would then be stored as a fuel intermediate for further processing to higher molecular-weight oxygenates. Economic, process, and market analyses will provide guidance as to which of these scenarios should be emphasized. The third and fourth campaigns will address higher alcohols or mixed ether production.

In the laboratory, the principal effort will be developing oxygenated fuel technologies from slurry-phase processing of coal-derived syngas using two approaches, (1) fuels from syngas directly, and (2) fuels from DME/methanol mixtures. Air Products has already demonstrated the unique ability of DME to act as a chemical building-block to higher molecular-weight oxygenated hydrocarbons.

Project Cost: $20.5 million FY91-FY93

LUBECK IGCC DEMONSTRATION PLANT—PreussenElektra (C-339)

The project of PreussenElektra/Germany has a capacity of 320 MWe net based on hard coal and a net efficiency of 45 percent. PRENOL gasification technology has been chosen for the gasifier.

LU NAN AMMONIA-FROM-COAL PROJECT—China National Technical Import Corporation (C-360)

The China National Technical Import Corporation awarded a contract to Bechtel for consulting services on a commercial coal gasification project in the People's Republic of China. Bechtel will provide assistance in process design, design engineering, detailed engineering, procurement, construction, startup, and operator training for the installation of a 375 tons per day Texaco gasifier at the 200 metric tons per day Lu Nan Ammonia Complex in Tengxian, Shandong Province. The gasifier was completed in 1991, and has replaced an obsolete coal gasification facility with the more efficient Texaco process.

Project Cost: Not Disclosed

MILD GASIFICATION PROCESS DEMONSTRATION UNIT—Coal Technology Corporation and United States Department of Energy (DOE) (C-370)

Since the mid-1980s, Coal Technology Corporation (CTC), formerly UCC Research Corporation, has been investigating the pyrolysis of coal under sponsorship of DOE's Morgantown Energy Technology Center. This work initially was the development of a batch process demonstration unit having a coal feed capacity of 120 pounds per batch. The process produced coal liquids to be used for motor fuels and char to be potentially used for blast furnace coke and offgas.

In January 1988, DOE and CTC cost shared a $3,300,000 three-year program to develop a process demonstration unit for the pyrolysis of 1,000 pounds/hour of coal by a continuous process. This work involved a literature search to seek the best possible process; and then after small scale work, a proprietary process was designed and constructed. The unit began operating in February 1991. Test runs have been made with seven different caking bituminous coals and no major differences in coke making were observed.

In the CTC mild gasification process, coal is heated from ambient temperature to around 400°F in the first heat zone of the reactor, and then to 800 to 900°F in the second heat zone. Lump char discharged from the reactor is cooled in a water jacketed auger to 300°F. At present, the char is stored, but in an integrated facility, the cooled char would then be crushed, mixed with binder material and briquetted in preparation for conversion to coke in a continuous rotary hearth coker. The moisture and volatile hydrocarbons produced in the reactor are recovered and separated in scrubber/condensers into noncondensibles gases and liquids.
The coal liquid and coke (CLC) mild gasification technology to be demonstrated involves the production of two products from bituminous caking type coals: coal liquids for further refining into transportation fuels, and formed coke for foundry and blast furnace application in the steel industry. The CLC process will continuously produce blast furnace quality coke within a 2-hour duration in a completely enclosed system. The coal liquids will be recovered at less than 1,000°F for further refining into transportation fuel blend stock.

The processing involves feeding coal into three of CTC's proprietary mild gasification retort reactors operating at about 1,000°F to extract the liquids from the coal and produce a devolatized char. The hot char is fed directly into a hot briquette system along with additional coking coal to form what is called green briquettes. The green briquettes will directly feed into the specially designed rotary hearth continuous coking process for final calcining at 2,000°F to produce blast furnace formed coke. The small amount of uncondensed gases will be recirculated back through the system to provide a balanced heat source for the mild gasification retorts and the rotary hearth coking process. A total of 1,420 tons of coal per day will be used in the demonstration phase of this plant.

Three companies in Virginia have agreed to cosponsor this project as equity participants: Norfolk Southern Corporation, Coal Technology Corporation, and Rapoca Energy Company. The project was submitted to DOE under the Clean Coal Technology Program Round 4, but was not selected for funding.

Wise County Industrial Park was selected as the primary site for this plant. The 32 acre site is adjacent to massive high quality coal reserves and the Norfolk Southern rail system now extends to the site. Wise County has agreed to donate the leveled site as an incentive for the location of this plant in their county. The Virginia Coalfield Economic Development Authority has agreed to provide various financial incentives to locate the plant in this area of Virginia.

American Electric Power of Lancaster, Ohio is initiating a pilot program at its subsidiary, Appalachian Power in Abington, Virginia, to test liquid coal fuel in part of its vehicle fleet. The program will test petroleum fuel with 10 percent liquid coal fuel added.

Some experimental tests of char for steel making in a full scale electric arc furnace were scheduled for late 1991. Char from the continuous mild gasification process will be used.

Project Cost: $124.5 million for the process demonstration plant

MILD GASIFICATION OF WESTERN COAL DEMONSTRATION – AMAX, Western Research Institute (C-372)

AMAX is planning a 1,000 ton per day mild gasification commercial demonstration plant at its Eagle Butte Mine near Gillette, Wyoming. Inclined fluid-bed reactors will be used for drying and mild gasification. Amax is studying ways to best market all of the char and liquid products produced.

The first liquid product, dirty pitch, will be marketed as a binder for carbon anodes used in aluminum production. A lighter fraction would be sold as chemical feedstock. The oil product will be used as diesel additive to run the heavy mine equipment or to spray on dry coal.

Prefeasibility studies concluded that favorable economics depend upon upgrading the mild gasification chars to a higher value product. This is because char has lower volatile matter content and higher ash content than the starting coal. These characteristics make char a low value utility fuel. Amax has been developing a char-to-carbon (CTC) process to convert the char to pure carbon and activated carbon. Pure carbon is to be used for the manufacture of carbon anodes in aluminum production or sold as carbon black. Its use as a premium fuel for gas turbines and heat engines offers the largest long-term market. The waste streams will be incinerated in an atmospheric fluidized-bed combustor which, in addition to supplying process heat, will produce electric power for export.

A 100 pound per hour inclined fluid bed mild gasification process research unit has been operating at Western Research Institute since January 1990. A 50 pound per hour CTC process demonstration unit was started up at Amax Research and Development in Golden, Colorado in 1990. A proposal was submitted to the U.S. Department of Energy in 1990 for design, construction, operation and evaluation of 20 ton per day integrated process development unit at Golden.

MONASH HYDROLIQUEFACTION PROJECT – Coal Corporation of Victoria and Monash University (C-380)

The Chemistry, Chemical Engineering, and Physics Departments at Monash University at Clayton, Victoria are conducting a major investigation into the structure and hydroliquefaction of Victorian brown coal. Batch autoclave and other studies are being conducted.

The work is largely supported by the Coal Corporation of Victoria and NERDDC.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

Earlier studies on the hydroliquefaction of brown coal have led to a more detailed study of its structure and reactivity and are based on extensive collaborations with a number of other laboratories in Australia. These led to the proposal of a guest/host model for brown coal which more recent results suggests may represent an oversimplification of coal structure. The nature of the bonding, chemical and/or physical, by which aliphatic material is retained in the lignocellulosic polymer has yet to be defined.

The use of sodium aluminate as a promoter for the reaction of brown coal with carbon monoxide and water, leading to high yields of low molecular weight products under relatively mild conditions without the use of a recycle solvent, has been established. Some success has been achieved in characterizing the aluminum species responsible for promoting these reactions but further work is required.

Partial oxidation of brown coal is thought to be adventitious for hydroliquefaction, particularly in the carbon monoxide/water/aluminate system.

A wide range of collaborative projects are currently in progress. Investigations are underway into the isolation and characterization of potentially useful products which can be extracted from brown coal.

Project Cost: $2.0 million (Australian) since commencement

MONGOLIAN ENERGY CENTER - People's Republic of China (C-390)

One of China's largest energy and chemical materials centers is under construction in the southwestern part of Inner Mongolia. The first-phase construction of the Jungar Coal Mine, China's potential largest open-pit coal mine with a reserve of 25.9 billion tons, is in full swing and will have an annual capacity of 15 million tons by 1995.

The Ih Je League (Prefecture) authorities have made a comprehensive development plan including a 1.1 billion CNY complex which will use coal to produce chemical fertilizers. A Japanese company has completed a feasibility report.

The region may be China's most important center of the coal-chemical industry and the ceramic industry in the next century.

MRS COAL HYDROGENATOR PROCESS PROJECT - British Gas plc and Osaka Gas Company Ltd. (C-400)

Work is being carried out jointly by British Gas plc and the Osaka Gas Company Ltd. of Japan, to produce methane and valuable liquid hydrocarbon coproducts by the direct thermal reaction of hydrogen with coal. A novel reactor, the MRS (for Midlands Research Station) coal hydrogenator incorporating internal gas recirculation in an entrained flow system has been developed to provide a means of carrying out the process without the problems of coal agglomeration, having to deal with excessive coal fines, or excessive hydrogenation gas preheat as found in earlier work.

A 200 kilogram per hour pilot plant was built to prove the reactor concept and to determine the overall process economics. The process uses an entrained flow reactor with internal gas recirculation based on the Gas Recycle Hydrogenator (GRH) reactor that British Gas developed to full commercial application for oil gasification.

Following commissioning of the plant in October 1987, a test program designed to establish the operability of the reactor and to obtain process data was successfully completed. An Engineering and Costing Study of the commercial process concept confirmed overall technical feasibility and exceptionally high overall efficiency giving attractive economics.

In December 1988, the sponsors went ahead with the second stage of the joint research program to carry out a further two year development program of runs at more extended conditions and to expand the pilot plant facilities to enable more advanced testing to be carried out.

Through 1989, performance tests have been conducted at over 43 different operating conditions. Four different coals have been tested, and a total of 10 tonnes have been gasified at temperatures of between 780 degrees centigrade and 1,000 degrees centigrade. The initial plant design only allowed tests of up to a few hours duration to be carried out. The plant was modified in early 1990 to provide continuous feeding of powdered coal and continuous cooling and discharge of the char byproduct and was operated in this mode starting in the second half of 1990.

Project Cost:  
Phase I  $16 million  
Phase II  $7.4 million

NEDO IGCC DEMONSTRATION PROJECT - New Energy and Industrial Technology Development Organization (NEDO) (C-408)

NEDO is studying integrated gasification combined cycle technology as part of a national energy program called the Sunshine Project. A 200 ton per day pilot plant has been constructed at the Nakoso power station site in Iwaki City, Fukushima Prefecture. The pilot began operating in March 1991.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

The plant, which is designed to produce 42,900 cubic meters of synthetic gas per hour, is expected to operate for about 2 years using four different kinds of coal. The gasifier is an air blown, two stage entrained flow type with a dry-feeding system.

NEDO's goal is to develop a 250 megawatt demonstration plant by the year 2000 that has a net thermal efficiency greater than 43 percent and better operability than existing pulverized coal-fired plants. In order to obtain this goal, the development of the entrained flow gasification pilot plant will be followed by a fluidized bed gasification pilot plant.

NEDOL BITUMINOUS COAL LIQUEFACTION PROCESS - New Energy Development Organization (NEDO) (C-410)

Basic research on coal liquefaction was started in Japan when the Sunshine project was inaugurated in 1974, just after the first oil crisis in 1973. NEDO assumed the responsibility for development and commercialization of coal liquefaction and gasification technology. NEDO plans a continuing high level of investment for coal liquefaction R&D, involving two large pilot plants. The construction of a 50 tons per day brown coal liquefaction plant was completed in December 1986 in Australia, and a 150 tons per day bituminous coal liquefaction plant is planned in Japan.

The pilot plant in Australia is described in the project entitled "Victoria Brown Coal Liquefaction Project." The properties of brown coal and bituminous coal are so different that different processes must be developed for each to achieve optimal utilization. Therefore, NEDO has also been developing a process to liquefy sub-bituminous and low grade bituminous coals. NEDO had been operating three process development units (PDU's) utilizing three different concepts for bituminous coal liquefaction: solvent extraction, direct liquefaction, and solvolysis liquefaction. These three processes have been integrated into a single new process, so called NEDOL Process, and NEDO has intended to construct a 150 tons per day pilot plant.

In the proposed pilot plant, bituminous coal will be liquefied in the presence of activated iron catalysts. Synthetic iron sulfide or iron dust will be used as catalysts. The heavy fraction (-538 degrees C) from the vacuum tower will be hydrotreated at about 350 degrees C and 100-150 atm in the presence of catalysts to produce hydrotreated solvent for recycle. Consequently, the major products will be light oil. Residue-containing ash will be separated by vacuum distillation.

Detailed design of the new pilot plant has been completed. It is expected that the pilot plant will start operation in 1991.

In 1988, 5 different coals were processed in the bench scale unit with encouraging results.

Project Cost: 100 billion yen, not including the three existing PDU

P-CIG PROCESS – Interproject Service AB (Sweden) and Nippon Steel Corporation, Japan (C-455)

The Pressurized-Coal Iron Gasification process (P-CIG) is based on the injection of pulverized coal and oxygen into an iron melt at overatmospheric pressure. The development started at the Royal Institute of Technology in Stockholm in the beginning of the 1970s with the nonpressurized CIG Process. Over the years work had been done on ironmaking, coal gasification and ferroalloy production in laboratory and pilot plant scale.

In 1984, Interproject Service AB of Sweden and Nippon Steel Corporation of Japan signed an agreement to develop the P-CIG Process in pilot plant scale. The pilot plant system was built at the Metallurgical Research Station in Lulea, Sweden. The P-CIG Process utilizes the bottom blowing process for injection of coal and oxygen in the iron melt. The first tests started in 1985 and several test campaigns were carried out through 1986. The results were then used for the design of a demonstration plant with a gasification capacity of 500 tons of coal per day.

According to project sponsors, the P-CIG Process is highly suitable for integration with combined cycle electric power generation. This application might be of special interest for the future in Sweden.

For the 500 tons of coal per day demonstration plant design, the gasification system consisted of a reactor with a charge weight of 40 tons of coal. Twenty-two tons of raw coal per hour would be crushed, dried and mixed with five tons of flux and injected together with 9,000 cubic meters of oxygen gas.

PETC GENERIC COAL LIQUEFACTION PLANTS—United States Department of Energy (DOE), M.W. Kellogg Company (C-457)

DOE's Pittsburgh Energy Technology Center (PETC) has awarded Kellogg a contract to engineer, fabricate, install and commission three generic pilot plants to be installed at the center. The plants, which will be skid mounted, include direct coal liquefaction, indirect coal liquefaction, and product upgrading units. These pilot plants will be used by PETC to test new concepts for improving these processes and will allow testing of new processes and catalysts by outside contractors who do not have facilities for such testing. The facilities are scheduled to be completed by mid-1993.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

PINON PINE IGCC POWER PLANT – Sierra Pacific Power Company (C-458)

Sierra Pacific Power Company is planning to build an 80 MW integrated gasification combined cycle plant at its Tracy Power Plant site, east of Reno, Nevada. The plant will incorporate an air-blown KRW fluidized bed gasifier producing a low-BTU gas for the combined cycle power plant. The demonstration project will have a heat rate of 9,500 BTU/kWh.

Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier through a lockhopper system. The bed is fluidized by the injection of air and steam through special nozzles into the combustion zone. Crushed limestone is added to the gasifier to capture a portion of the sulfur introduced with the coal as well as to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits along with the coal ash in the form of agglomerated particles suitable for landfill.

In the demonstration project, a nominal 800 tons per day of coal is converted into 86 megawatts; support facilities for the plant require 6 megawatts, leaving 80 megawatts for export to the grid. The project will be designed to run on Western subbituminous coal from Utah; operation with higher sulfur and lower rank coals also is being considered.

The U.S. Department of Energy (DOE) has agreed to fund half of the $270 million project cost. The project is funded by DOE through the Clean Coal Technology Program, Round 4. Sierra Pacific Power will fund the remaining 50%.

Foster Wheeler USA Corp. has been contracted to provide design, engineering, construction, manufacturing and environmental services for the project.


Project Cost: $270 million

POLISH DIRECT LIQUEFACTION PROCESS – Coal Conversion Institute, Poland (C-460)

In 1975, Polish research on efficient coal liquefaction technology was advanced to a rank of Government Program PR-1 "Complex Coal Processing," and in 1986 to a Central Research and Development Program under the same title. The leading and coordinating unit for the coal liquefaction research has been the Coal Conversion Institute, part of the Central Mining Institute.

Initial work was concentrated on the two-stage extraction method of coal liquefaction. The investigations were carried out up to the bench scale unit (120 kilograms of coal per day). The next step—tests on a Process Development Unit (PDU)—met serious problems with the mechanical separation of solids (unreacted coal and ash) from the coal extract, and continuous operation was not achieved. In the early eighties a decision was made to start investigations on direct coal hydrogenation under medium pressure.

Investigations of the new technology were first carried out on a bench-scale unit of five kilograms of coal per hour. The coal conversion and liquid products yields obtained as well as the operational reliability of the unit made it possible to design and construct a PDU scaled for two tonnes of coal per day.

The construction of the direct hydrogenation PDU at the Central Mining Institute was finished in the middle of 1986. In November 1986 the first integrated run of the entire unit was carried out.

The significant, original feature of this direct, non-catalytic, middle-pressure coal hydrogenation process is the recycle of part of the heavy product from the hot separator through the preheater to the reaction zone without pressure release. Thanks to that, a good distribution of residence times for different fractions of products is obtained, the proper hydrodynamics of a three-phase reactor is provided and the content of mineral matter (which acts as a catalyst) in the reactants is increased. From 1987 systematic tests on low rank coal type 31 have been carried out, with over 100 tons of coal processed in steady-state parameters.

The results from the operation of the PDU will be used in the design of a pilot plant with a capacity of 200 tonnes coal per day.

PRENFLO GASIFICATION PILOT PLANT – Krupp Koppers GmbH (KK) (C-470)

Krupp Koppers (KK) of Essen, West Germany (in United States known under the name of GKT Gesellschaft fuer Kohle-Technologie) are presently operating a 48 ton per day demonstration plant and designing a 2,400 ton per day module for the PRENFLO process. The PRENFLO process is KK's pressurized version of the Koppers-Toztek (KT) flow gasifier. Detailed engineering has been completed for a 1,200 ton per day module.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)
COMMERICAL AND R&D PROJECTS (Continued)

In 1973, KK started experiments using a pilot KT gasifier with elevated pressure. In 1974, an agreement was signed between Shell Internationale Petroleum Maatschappij BV and KK for a cooperation in the development of the pressurized version of the KT process. A demonstration plant with a throughput of 150 tons per day bituminous coal and an operating pressure of 435 psia was built and operated for a period of 30 months. After completion of the test program, Shell and KK agreed to continue further development separately, with each partner having access to the data gained up to that date. KK's work has led to the PRENFLO process.

Krupp Koppers has decided to continue development with a test facility of 48 tons per day coal throughput at an operating pressure of 30 bar. The plant is located at Fuerstenhausen, West Germany. In over 8,000 hours of test operation nine different fuels with ash contents of up to 40 percent were successfully used. All fuels used are converted to more than 98 percent, and in the case of fly ash recycled to more than 99.5 percent.

Project Cost: Not disclosed

PRESSURIZED FLUID BED COMBUSTION ADVANCED CONCEPTS - M. W. Kellogg Company (C-473)

In September of 1988, Kellogg was awarded a contract by the DOE to study the application of transport mode gasification and combustion of coal in an Advanced Hybrid power cycle. The study was completed in 1990 and demonstrated that the cycle can reduce the cost of electricity by 20-30 percent (compared to a PC/FGD system) and raise plant efficiency to 45 percent or more.

The Hybrid system combines the advantages of a pressurized coal gasifier and a pressurized combustor which are used to drive a high efficiency gas turbine generator to produce electricity. The proprietary Kellogg system processes pulverized coal and limestone and relies on high velocity transport reactors to achieve high conversion and low emissions.

DOE, in late 1990, awarded a contract to Southern Company Services, Inc. for addition of a Hot Gas Cleanup Test Facility to their Wilsonville test facility. The new unit will test particulate removal devices for advanced combined cycle systems and Kellogg's Transport gasifier and combustor technology will be used to produce the fuel gas and flue gas for the testing program. The reactor system is expected to process up to 48 tons per day of coal. [See Hot Gas Cleanup Process (C-257)].

Kellogg has built a bench scale test unit to verify the kinetic data for the transport reactor system and is currently conducting tests in both gasification and combustion modes. Initial test results in both modes have verified the concept, supporting the thesis that reactors designed to process pulverized coal can achieve commercial conversion levels while operating at high velocities and short contact times. These data will be used to support the design of the Wilsonville test gas generator.

The gasifier converts part of the coal to a low-BTU gas that is filtered and sent to the gas turbine. The remaining char is combusted and the flue gas is filtered and also goes to the gas turbine. The advantages of the system in addition to high efficiency are lower capital cost and greatly reduced SO and NO emissions.

DOE's Morgantown Energy Technology Center has awarded Kellogg a contract for experimental studies to investigate in-situ desulfurization with calcium-based sorbents. The testing, which will be conducted at Kellogg's Houston Technology Development Center, will investigate the effects of the sorbents on sulfur capture kinetics and carbon conversion kinetics, and the mechanism for conversion of calcium sulfide to calcium sulfate in second generation (hybrid) pressurized fluid bed combustion systems.

DOE has also approved the design, fabrication, installation and operation of a Process Development Unit (PDU) based upon Kellogg's Transport gasification process at the University of North Dakota, Energy and Environmental Research Center. The unit will process 1.5 tons per day of pulverized bituminous coal.

PUERTOLLANO IGCC DEMONSTRATION PLANT - Empresa Nacional de Electricidad, S.A. (ENDESA) (C-476)

The Spanish utility company ENDESA together with EDF/ France, IBERDROLA/Spain, Hidroeléctrica del Cantábrico/Spain, SEVILLANA/Spain, ENEL/Italy, and EDP/Portugal are involved in the Puertollano project. The project also has the European Economic Commission support, under the Thermie Program.

The proposed project has a capacity of approximately 300 MWe, which is influenced by the type of gas turbine selected (Siemens or Alsthom). The PRENFLO gasification technology has been chosen for the gasifier.

The plant configuration is single-train throughout. Using oxygen and steam, about 100 tons of coal per hour will be gasified. The required oxygen, approximately 90 tons per hour, will be produced in a single-train air separation unit. The resulting coal gas will be dedusted, desulfurized and saturated in a single-train configuration and then combusted in a single combustion turbine.

A 50/50 mixture of Puertollano coal and petroleum coke from the Puertollano Petroleum Refinery is intended to be the main feedstock for this project. Coals from England, Spain, France, the United States, China, Austria, Columbia, Germany, Poland and South Africa will also be tested over the 3-year demonstration period.
SO\textsubscript{2} Emission values of 10 mg/m\textsuperscript{3} and NO\textsubscript{x} values of 60 mg/m\textsuperscript{3} are expected in the exhaust gas (based on 15 volume percent oxygen).

Civil work is scheduled to begin in November 1992 with construction of the combined cycle components completed by December 1994. The gasification island is scheduled to be completed by December 1995, and commissioning with coal gas would take place in January 1996. The demonstration period, then, would be from 1996 to 1998.

RHEINBRAUN HIGH-TEMPERATURE WINKLER PROJECT – Rheinische Braunkohlenwerke AG, Uhde GmbH, Lurgi GmbH, German Federal Ministry for Research & Technology (C-480)

Rheinbraun and Uhde have been cooperating since 1975 on development of the High-Temperature Winkler fluidized bed gasification process. In 1990 Lurgi joined the commercialization effort.

Based on operational experience with various coal gasification processes, especially with ambient pressure Winkler gasifiers, Rheinische Braunkohlenwerke AG (Rheinbraun) in the 1960s decided to develop pressurized fluidized bed gasification, the High-Temperature Winkler (HTW) process. The engineering contractor for this process is Uhde GmbH.

The development was started at the "Institut für Eisenhüttenkunde" of Aachen Technical University in an ambient pressure process development unit (PDU) of about 50 kilograms per hour coal throughput.

Based on the results of pre-tests with this PDU a pilot plant operating at pressure of 10 bar was built in July 1978 at the Wachtberg plant site near Cologne. Following an expansion in 1980/1981, feed rate was doubled to 1.3 tons per hour dry lignite. By end of June 1983 the test program was finished and the plant was shut down. From 1978 until June 1985 about 21,000 tonnes of dried brown coal were processed in about 36,000 hours of operation. The specific synthesis gas yield reached 1,580 standard cubic meters per tonne of brown coal (MAP) corresponding to 96 percent of the thermodynamically calculated value. At feed rates of about 1,800 kilograms per hour coal, the synthesis gas output of more than 7,700 standard cubic meters per hour per square meter of gasifier area was more than threefold the values of atmospheric Winkler gasifiers.

After gasification tests with Finnish peat in the HTW pilot plant in the spring of 1984 the Kemira Oy Company of Finland decided to convert an existing ammonia production plant at Oulu from heavy oil to peat gasification according to the HTW process. The plant was designed to gasify approximately 650 tons per day of peat at 10 bar and process it to 280 tons per day of ammonia. This plant started up in 1988 and is operating successfully.

Rheinbraun constructed a 30 ton per hour demonstration plant for the production of 300 million cubic meters of syngas per year. All engineering for gasifier and gas after-treatment including water scrubber, shift conversion, gas clean up and sulfur recovery was performed by Uhde; Linde AG is contractor for the Rectisol gas cleanup. The synthesis gas produced at the site of Rheinbraun’s Ville/Berrenrath briquetting plant is pipelined to DEA-Union Kraftstoff for methanol production testing periods. From startup in January 1986 until the end of October 1991 about 755,000 tonnes of dried brown coal, especially high ash containing steam coal, were processed in about 31,900 hours of operation. During this time, about 996 million cubic meters of synthesis gas were produced.

A new pilot plant, called HTW-pressurized plant, for pressures up to 25 bar and throughputs up to 6.5 tonnes per hour was erected on the site of the former pilot plant of hydrogasification and started up in November 1989. From mid-November 1989 to early July 1990, the plant was operated at pressures between 10 and 25 bar, using oxygen as the gasifying agent. Significant features of the 25 bar gasification are the high specific coal throughput and, consequently, the high specific fuel gas flow of almost 100 MW per square meter. In mid-1990, the 25 bar HTW plant was modified to permit tests using air as the gasifying agent. Until the end of October 1991 the plant was operated for 7,515 hours at pressures of up to 25 bar, oxygen blown as well as air blown. Under all test and operating conditions gasification was uniform and trouble free.

Typical results obtained are: up to 95 percent coal conversion, over 70 percent cold-gas efficiency and 50 MW\textsubscript{th} specific fuel gas flow per square meter air blown and 75 percent cold-gas efficiency and 105 MW\textsubscript{th} specific fuel gas flow per square meter oxygen blown.

This work is performed in close co-ordination with Rheinbraun’s parent company, the Rheinisch-Westfälisches Elektrizitätswerk (RWE), which operates power stations of a capacity of some 9,300 megawatts on the basis of lignite. Since this generating capacity will have to be renewed after the turn of the century, it is intended to develop the IGCC technology so as to have a process available for the new power plants. Based on the results of these tests and on the operating experience gained with the HTW pressurized plant, a demonstration plant for integrated HTW gasification combined cycle (HTW-IGCC) power generation is planned which will go on stream in 1995 and will have a capacity of 300 MW of electric power. See KOBRA HTW-IGCC Project (C-294).

Project Cost: Not disclosed
SASOL - Sasol Limited (C-490)

Sasol Limited is the holding company of the multi divisional Sasol Group of Companies. Sasol is a world leader in the commercial production of coal based synthetic fuels. The Synthol oil-from-coal process was developed by Sasol in South Africa in the course of more than 30 years. A unique process in the field, its commercial-scale viability has been fully proven and its economic viability conclusively demonstrated.

The first Sasol plant was established in Sasolburg in the early fifties. The much larger Sasol Two and Three plants, at Secunda—situated on the Eastern Highveld of Transvaal, came on-stream in 1980 and 1982, respectively.

The two Secunda plants are virtually identical and both are much larger than Sasol One, which served as their prototype. Enormous quantities of feedstock are produced at these plants. At full production, their daily consumption of coal is almost 100,000 tons, of oxygen, 26,000 tons; and of water, 160 megaliters. Sasol's facilities at Secunda for the production of oxygen are by far the largest in the world.

Facilities at the fuel plants include boiler houses, Lurgi gasifiers, oxygen plants, Rectisol gas purification units, synthol reactors, gas reformers and refineries. Hydrocarbon synthesis takes place by means of the Sasol developed Synthol process.

The products of Sasol Two and Three, other than liquid fuels, include ethylene, alcohols, acetone, methyl ethyl ketone, pitch, tar acids, and sulfur, produced for Sasol's Chemical Division, ammonia for the group's Fertilizer and Explosives Divisions, and propylene for the Polypropylene Division. The primary fuels produced by Sasol at Secunda are probably among the most environmentally acceptable in the world. The gasoline that is produced has zero sulfur content, is low in aromatics and the level of oxygenates means a relatively high octane number. An oxygenate-containing fuel, as a result of the lower combustion temperature, results in a generally lower level of reactive exhaust constituents.

The blending of synthetic gasoline with alcohols (ethanol as well as high fuel alcohols) presented a particular challenge to Sasol. Sasol erected research and development facilities to optimize and characterize fuel additives. Whereas carburetor corrosion with alcohol-containing gasoline occurs with certain alloys used for carburetors, Sasol has now developed its own package of additives to the point where a formal guarantee is issued to clients who use Sasol fuel.

The diesel fuel is a zero sulfur fuel with a high cetane number and a paraffin content that will result in a lower particulate emission level than normal refinery fuel.

Sasol's Mining Division manages the six Sasol-owned collieries, which have an annual production in excess of 43 million tons of coal. The collieries comprised of the four Secunda Collieries (including the new open cast mine, Syferfontein), which form the largest single underground coal mining complex in the world, and the Sigma Colliery in Sasolburg.

A technology company, Sastech, is responsible for the Group's entire research and development program, process design, engineering, project management, and transfer of technology.

Sasol approved in 1990 six new projects costing $451 million as part of an overall $1.1 billion program over the next five years. The first three projects are scheduled for completion by January 1993.

Sasol has increased its production of ethylene by 60,000 tons per year, to a current level of 400,000 tons per year, by expanding its ethylene recovery plant at Secunda.

The company's total wax producing capacity will be doubled from its current level of 64,000 tons per year to 123,000 tons per year.

The 70,000 ton per year Sasol One ammonia plant is to be replaced by a 240,000 ton per year plant, which is expected to supply South Africa's current ammonia supply shortfall.

A new facility is to be built as Sasol One to manufacture paraffinic products for detergents. The other three newly approved projects, which will be located at Sasol's Secunda facilities, are:

- An n-butanol plant to recover acetaldehyde from the Secunda facilities and to produce 17,500 tons per year of n-butanol is being built. The plant is expected to come on stream in January 1992.

- Sasol will construct a delayed coker to produce green coke, and a calciner to calcinate the green coke to anode coke and needle coke. The anode coke is suitable for use in the aluminum smelting industry. They are scheduled to be in production by March 1993.

- A flexible plant to recover 100,000 tons per year of 1-hexane or 1-pentone will be built to come online in January 1994.

- Krypton and xenon gases will be recovered from the Secunda oxygen units.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

A major renewal project at Sasol One includes an expansion of the fixed bed Fischer-Tropsch plant. The renewal also includes shutting down much of the synthetic fuels capability at this plant.

Project Cost:  
SASOL Two $2.9 Billion  
SASOL Three $3.8 Billion

*At exchange rates ruling at construction

SCOTIA COAL SYNFUELS PROJECT – DEVCO; Alastair Gillespie & Associates Limited; Gulf Canada Products Company; NOVA; Nova Scotia Resources Limited; and Petro-Canada (C-500)

The consortium conducted a feasibility study of a coal liquefaction plant in Cape Breton, Nova Scotia using local coal to produce gasoline and diesel fuel. The plant would be built either in the area of the Point Tupper Refinery or near the coal mines. The 25,000 barrels per day production goal would require approximately 2.5 million tonnes of coal per year. A contract was completed with Chevron Research Inc. to test the coals in their two-stage direct liquefaction process (CCLP). A feasibility report was completed and financeability options discussed with governments concerned and other parties.

Scotia Synfuels Limited has been incorporated to carry on the work of the consortium. Scotia Synfuels has down-sized the project to 12,500 barrels per day based on a coprocessing concept and purchased the Point Tupper site from Ultramar Canada Inc. Recent developments in co-processing technology have reduced the capital cost estimates to US$375 million. Net operating costs are estimated at less than US$20 per barrel.

In late 1988 Hydrocarbon Research Inc. (HRl) was commissioned by Scotia Synfuel Ltd. to perform microautoclave and bench scale tests to demonstrate the feasibility of their co-processing technology using Harbour seam coal and several oil feedstocks. In early 1989, Bantrel Inc. (a Canadian engineering firm affiliated with Bechtel Inc.), was commissioned to develop a preliminary process design.

Scotia Synfuels and partners have concluded an agreement with the Nova Scotia government supported by the federal government for financial assistance on a $2.5 million coprocessing feasibility study. The study was completed in 1990.

Based on the test program results, material and energy balances were developed for a commercial facility. An economic model was developed to analyze a number of options. The model incorporated government investment support programs available in eastern Canada. The primary incentives were investment tax credits and loan financing.

Discussions on project financing continued in 1991 with the governments of Canada and Nova Scotia and private corporations.

Project Cost:  
Approximately $2.5 million for the feasibility study  
Approximately C$500 million for the plant

SEP IGCC POWER PLANT—Demkolec B.V. (SEP) (C-520)

In 1989, Demkolec, a wholly owned subsidiary of Samenwerkende Elektriciteits-Produktiebedrijven (SEP), the Central Dutch electricity generating board, started to build a 253 megawatt integrated gasification combined cycle (IGCC) power plant, to be ready in 1993.

SEP gave Comprimo Engineering Consultants in Amsterdam an order to study the gasification technologies of Shell, Texaco and British Gas/Lurgi. In April 1989 it was announced that the Shell process had been chosen. The location of the gasification/combined cycle demonstration station is Buggenum, in the province of Limburg, The Netherlands.

The coal gasification facility will employ a single 2,000 ton per day gasifier designed on the basis of SCGP-1. The clean gas will fuel a single shaft Siemens V94.2 gas turbine (156 MWe) coupled with steam turbine (128 MWe) and generator. The SCGP plant will be fully integrated with the combined cycle plant, including the boiler feed water and steam systems; additionally the compressed air for the air separation plant will be provided as a bleed stream from the compressor of the gas turbine. The design heat rate on internationally traded Australian coal (Drayton) is 8,240 BTU/kWh based on coal higher heating value (HHV).

Environmental permits based on NO, emissions of 0.17 lb/MMBTU and SO, emissions of 0.06 lb/MMBTU were obtained in April 1990. Construction began in July 1990 and start of operation is scheduled for September 1993. When operation begins, the Demkolec plant will be the largest coal gasification combined cycle power plant in the world.

After three years of demonstration (1994 to 1996), the plant will be handed over to the Electricity Generating Company of South Netherlands (N.V. EPZ).

Project Cost:  
Dfl. 880 million (1989)

SYNTHETIC FUELS REPORT, JUNE 1992

4-72
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

SHANGHAI CHEMICALS FROM COAL PLANT – People’s Republic of China (C-525)

The Chinese government has approved construction of a new methanol complex. Using coal as raw material, the Shanghai-based plant is expected to produce 100,000 tons per year of methanol and 15,000 tons per year of acetate fiber. Completion is due in 1992.

SHOUGANG COAL GASIFICATION PROJECT – People’s Republic of China (C-527)

The Shougang plant will gasify 1,170 tons per day of Chinese anthracite using the Texaco coal gasification process. The gasification plant will produce fuel gas for an existing steel mill and town gas. The detailed design is being completed and equipment fabrication is underway. The plant is expected to be operational in late 1992.

SLAGGING GASIFIER PROJECT – British Gas Corporation (C-540)

The British Gas Corporation (BGC) constructed a prototype high pressure slagging fixed bed gasifier in 1974 at Westfield, Scotland. (This gasifier has a 6 foot diameter and a throughput of 300 tons per day.) The plant successfully operated on a wide range of British and American coals, including strongly caking and highly swelling coals. The ability to use a considerable proportion of fine coal in the feed to the top of the gasifier has been demonstrated as well as the injection of further quantities of fine coal through the tuyeres into the base of the gasifier. Byproduct hydrocarbon oils and tars can be recycled and gasified to extinction. The coal is gasified in steam and oxygen. The slag produced is removed from the gasifier in the form of granular frit. Gasification is substantially complete with a high thermal efficiency. A long term proving run on the gasifier has been carried out successfully between 1975 and 1983. Total operating time was over one year and over 100,000 tons of coal were gasified.

A new phase, started in November 1984, is the demonstration of a 500 ton per day (equivalent to 70 megawatts) gasifier with a nominal inside diameter of 7.5 feet. Integrated combined cycle tests will be carried out with an SK 30 Rolls Royce Olympus turbine to generate power for the grid. The turbine is supplied with product gas from the plant. It has a combustor temperature of 1,950°F, a compression ratio of 10, and a thermal efficiency of 31 percent. By 1989 this gasifier had operated for approximately 1,300 hours and has gasified over 26,000 tons of British and American (Pittsburgh No. 8 and Illinois No. 6) coals.

Progressive development of the gasifier components has continued. The two main items of attention have been the stirrer at the top of the fuel bed and the distribution of steam and oxygen at the bottom of the fuel bed.

In addition to the current 500 ton per day gasifier, an experimental gasifier designed to operate in the fixed bed slagger mode at pressure up to 70 atmospheres was constructed in 1988. It is designed for a throughput of 200 tons per day. The unit is to be used to study the effect of pressure on methane production and gasifier performance.

Project Cost: Not available

SOUTH AUSTRALIAN COAL GASIFICATION PROJECT – Government of South Australia (C-550)

The South Australian Government is continuing to assess the feasibility of building a coal gasification plant utilizing the low rank brown coal of the Northern St. Vincent Basin deposits, north of Adelaide. The plant being studied would be integrated with two 300 MW combined cycle power station modules and is one possible option for meeting additional power station capacity requirements in the mid-1980s.

Coal has been tested in a number of processes including the Sumitomo CGS (molten iron bath), Westinghouse, Shell-Koppers and Texaco, and studies are continuing in conjunction with Sumitomo, Uhde-Steag, and Krupp-Koppers. Heads of Agreement were signed with a consortium headed by Uhde GmbH to test coal from the Bowmans deposit in the Rheinbraun HTW gasifier and perform a detailed design and feasibility study for a 600 MW gasification combined cycle power station. Ten tonnes of Bowmans coal were satisfactorily gasified in the small scale Process Development Unit at Aachen, FRG, in August 1985, and a further 500 tonnes were tested in the 40 ton per day Rheinbraun pilot plant at Frechen-Wachberg, FRG in December 1986.

The third phase, the detailed costing and feasibility study, was deferred indefinitely in 1988 due to deferred need for new electric capacity with significantly reduced electricity load growth.

Project Cost: DM 7.5 million

SYNTHESEGASANLAGE RUHR (SAR) – Ruhrkohle Oel und Gas GmbH and Hoechst AG (C-560)

Based on the results of the pressurized coal-dust gasification pilot plant using the Texaco process, which has been in operation from 1978 to 1985, the industrial gasification plant Synthesegasanlage Ruhr has been completed on Ruhrchemie’s site at Oberhausen-Holten.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

The 800 tons per day coal gasification plant has been in operation since August 1986. The coal gases produced have the quality to be fed into the Ruhrchemie's oxosynthesis plants. The gasification plant has been modified to allow for input of either hard coal or heavy oil residues. The initial investment was subsidized by the Federal Minister of Economics of the Federal Republic of Germany. The Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia participates in the coal costs.

Project Costs: DM220 million (Investment)

TAMPELLA IGCC PROCESS DEMONSTRATION - Tampella Power (C-565)

After having obtained the rights to the Institute of Gas Technology's fluidized bed gasification technology in 1989, Tampella Keeler began to design and initiate construction of a 10 MW thermal pilot plant at their research facilities in Tampere, Finland. The pilot plant is considered essential for determining operating parameters for specific coals and for continuing process development in the areas of in-gasifier sulfur capture and hot gas cleanup. The pilot plant will be operational in early 1991.

The pilot plant is designed so that alternative hot gas filters and zinc ferrite absorber/regenerator design concepts can be evaluated. The gasifier is 66 foot tall, with an inside diameter ranging from 2 to 4 feet. The gasifier will be capable of operating at pressures up to 425 psig.

After the pilot plant construction was underway, Tampella turned its attention towards locating a demonstration project in Finland and one in the U.S. A cogeneration project to be located at an existing paper mill has been selected as the basis for the demonstration in Finland. The gasifier will have a capacity of 150 MW thermal which is equal to about 500 tons per day of coal consumption. The plant will produce about 60 MW of electricity and about 60 MW equivalent of district heating.

In September, 1991 Tampella received support from the U.S. Department of Energy (DOE) to build an integrated gasification combined-cycle demonstration facility, known as the Toms Creek IGCC Demonstration Project, in Coeburn, Wise County, Virginia (see project C-580, below). The Toms Creek Project will utilize Tampella Power's advanced coal gasification technology to demonstrate improved efficiency for conversion of coal to electric power while significantly reducing SO₂ and NOₓ emissions.

TECO IGCC PLANT - Teco Power Services, U.S. Department of Energy (C-567)

A 120 MW(e) coal-gas based combustion turbine combined cycle power generating system is planned for Lakeland, Polk County, Florida. The plant will include an air blown/integrated gasification system providing fuel to a conventional combustion turbine combined cycle base load unit. The system is to be built such that natural gas is initially used and coal gas is introduced a couple of months later. Natural gas will then be used as the backup fuel. In this way, the system will simulate (in sequence if not in actual time) the phased construction of today's combined cycle plants designed for long-term compatibility with coal gas conversions.

The project, originally proposed as a 120 MW independent power project costing $400 million, was to be built on a site outside Tallahassee, Florida near the existing Arvah B. Hopkins Power Station. Public opposition and stalled negotiations with city officials forced Tampa Electric to change the location. A nominal 1,270 tons per day of coal will be converted to electricity. High-sulfur Illinois Basin coal will be used.

The air blown integrated gasification combined cycle (IGCC) project is being developed by TECO Power Services (TPS), a subsidiary of Tampa Electric. TPS will develop the project under commercial terms and conditions using a United States Department of Energy program subsidy to reduce financial risks associated with the coal gasification phase of the plant.

A coal gasification system is added in which coal is first gasified under pressure using steam and air to produce a low BTU fuel gas. The low BTU coal gas produced in the fixed-bed gasifier then goes to a hot gas cleanup (HGCU) subsystem where the removal of sulfur compounds is accomplished in a solid sorbent bed. Because the sulfur that was present in the coal is removed prior to combustion, scrubber equipment size and costs are potentially reduced. The cleaned gas is then delivered to a conventional gas turbine modified to include a set of low BTU gas nozzles.

The gasifier will employ the Lurgi "fixed bed" design. Questions to be addressed by the Florida project include how much the $/kW level increases for the IGCC on an installed basis as compared to a conventional combined cycle and what is the $/kWh cost of operation (including fuel, maintenance, spares, etc.) when utilizing coal as compared to natural gas. Since the total cost of a 220 MW natural gas based combined cycle system planned today is approximately $600/kW, a price of $600-700/kW (plus heat rate premium) is targeted for the coal gasification plant if the IGCC is to compete favorably with pulverized coal based systems with scrubbers.

Project Cost: $241.5 million
COMMERCIAL AND R&D PROJECTS (Continued)

TEXACO COOL WATER PROJECT - Texaco Syngas Inc. and Air Products and Chemicals, Inc. (C-569)

Original Cool Water participants built a 1,000-1,200 tons per day commercial-scale coal gasification plant using the oxygen-blown Texaco Coal Gasification Process. The gasification system which includes two Syngas Cooler vessels, was integrated with a General Electric combined cycle unit to produce approximately 122 megawatts of gross power. Plant construction, which began in December 1981, was completed on April 30, 1984, within the projected $300 million budget. A five-year demonstration period was completed in January 1989. See "Cool Water Project" in the December 1991 issue of the Synthetic Fuels Report, Status of Projects section for details of the original completed project.

Texaco plans to modify and reactivate the existing facilities to demonstrate new activities which include the addition of sewage sludge into the coal feedstock, production of methanol, and carbon dioxide recovery.

Texaco intends to use a new application of Texaco's technology which will allow the Cool Water plant to convert municipal sewage sludge to useful energy by mixing it with the coal feedstock. Texaco has demonstrated in pilot runs that sludge can be mixed with coal and, under high temperatures and pressures, gasified to produce a clean synthesis gas. The plant will produce no harmful byproducts.

Texaco will participate with Air Products, Chemical Inc. and the Department of Energy (DOE) to demonstrate the production of up to 150 TPD of liquid phase methanol (LPMEOH) under a U.S. Department of Energy Clean Coal Technology Round 3 award. Texaco also plans to recover approximately 200 TPD of liquid CO2. Texaco has submitted permit applications to the California Energy Commission and the U.S. Environmental Protection Agency and has received Federal Energy Regulatory Commission designation as a Qualifying Facility Cogenerator. DOE will fund 43 percent of the $213.7 million project cost.

Acquisition of the plant is conditioned upon finalizing the terms of the purchase agreement and the completion of negotiations with utilities for the sale of electricity to be produced. In addition, negotiations will be required with municipalities and other governmental entities that produce and handle sewage sludge.

Upon conclusion of the necessary negotiations, Texaco will invest additional capital in the plant for modifications and additions aimed at reopening the facility in late 1993.

Project Cost: $263 million for original Cool Water Coal Gasification Program
$213.7 million for the commercial demonstration of the liquid-phase methanol process

TEXACO MONTEBELLO RESEARCH LABORATORY STUDIES - Texaco Inc. (C-571)

Texaco has a number of on-going coal gasification research and development programs at its Montebello Research Laboratory (MRL). MRL is a major pilot-scale process development facility which has been involved in gasification research since 1946. It currently has three gasifiers with rated capacities of 15-30 tons per day of coal. These units are also capable of feeding a wide range of other solid and liquid fuels.

MRL serves the dual purpose of doing research and pilot unit testing for the development of the Texaco Gasification Process (TGP), and obtaining data required for the design and environmental permitting of commercial plants. In recent years, the research emphasis has expanded to include the improved integration of the gasification process with the overall chemical or power plant. This has involved the development of high temperature syngas cleanup technology (jointly funded by the U.S. Department of Energy), improved low temperature acid gas removal processes and engineering studies aimed at increasing the efficiency and reducing the cost of Texaco gasification based chemical and power generation plants.

In addition, the research also continues to expand the already wide range of feeds which can be gasified by the TGP. Recent work has included oily wastes, Orimulsion, contaminated soil and sewage sludge.

THERMOCHEM PULSE COMBUSTION DEMONSTRATION - ThermoChem, Inc., Weyerhauser and U.S. Department of Energy (C-577)

ThermoChem will demonstrate Manufacturing and Technology Conversion International's (MTCI) pulse combustor in an application for steam gasification of coal. This gasification process will produce a medium BTU content fuel gas from subbituminous coal at Weyerhauser Paper Company's Containerboard Division mill in Springfield, Oregon. The fuel gas and byproduct steam produced by this demonstration unit will be used in the mill to offset use of existing hog-fuel boilers. The eventual replacement of all existing five hog-fuel boilers is contemplated.

This demonstration will be of an industrial size gasifier. The heat required for the gasification will be supplied by the combustion of cleaned gasification products (fuel gas) in numerous pulsed combustion tubes. The products of pulsed combustion are separated from the gasification products. Since no dilution of the byproducts of combustion or of gasified fuel gas occurs, a medium BTU
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

Content fuel (500 BTU/scf) gas will be produced. The turbulent nature of the pulsed combustor contributes to a high combustion heat release density and high heat transfer rates to the gasifier bed. The fluidized bed coal gasifier also offers high turbulence and heat transfer rates.

The objective of the ThermoChem project is the demonstration of a 420 ton per day (as-received coal) novel coal gasification unit. It will supply a product fuel gas with a heating value of 161.2 million BTU/hr for boiler fuel. Use of the fuel gas in place of hog-fuel boilers will lower particulate emissions at the host facility. Another goal of the project is to determine whether gasification can be used on other potential energy sources, such as pulp-making byproducts.

The U.S. Department of Energy will fund 50% of the project under Round 4 of the Clean Coal Technology Program. Weyerhauser and ThermoChem will split the rest of the project.

Project Cost: $37.3 million

TOM'S CREEK IGCC DEMONSTRATION PLANT - TAMCO Power Partners and U.S. Department of Energy (C-580)

TAMCO Power Partners, a partnership between Tampella Power Corporation and Coastal Power Production Company will build an integrated gasification combined cycle power plant in Coeburn, Virginia. The U.S. Department of Energy will fund 50% of the $291 million project under Round 4 of its Clean Coal Technology Program.

The project will demonstrate a single air blown fluidized bed gasifier, based on the U-GAS technology developed by the Institute of Gas Technology. The plant will burn 430 tons per day of local bituminous coal and produce a net 55 MWe. Power will be generated with two gasifiers (one coal gas fired, one natural gas fired), and one steam turbine.

Project Cost: $291.1 million

UBE AMMONIA-FROM-COAL PLANT - Ube Industries, Ltd. (C-590)

Ube Industries, Ltd., of Tokyo completed the world's first large scale ammonia plant based on the Texaco coal gasification process (TCGP) in 1984. There are four complete trains of quench mode gasifiers in the plant. In normal operation three trains are used with one for stand-by. Ube began with a comparative study of available coal gasification processes in 1978. In October of that year, the Texaco process was selected. 1981 saw pilot tests run at Texaco's Montebello Research Laboratory, and a process design package was prepared in 1982. Detailed design started in early 1983, and site preparation in the middle of that year. Construction was completed in just over one year. The plant was commissioned in July 1984, and the first drop of liquid ammonia from coal was obtained in early August 1984. Those engineering and construction works and commissioning were executed by Ube's Plant Engineering Division. Ube installed the new coal gasification process as an alternative "front end" of the existing steam reforming process, retaining the original synthesis gas compression and ammonia synthesis facility. The plant thus has a wide range of flexibility in selection of raw material depending on any future energy shift. It can now produce ammonia from coals, naphtha and LPG as required.

The 1,650 tons per day gasification plant has operated using four kinds of coal—Canadian, Australian, Chinese, and South African. Over 2.5 million tons of feed including 200,000 tons of petroleum coke, had been gasified by 1990. The overall cost of ammonia is said by Ube to be reduced by more than 20 percent by using coal gasification. Furthermore, the coal gasification plant is expected to be even more advantageous if the price difference between crude oil and coal increases.

Project Cost - Not disclosed

VEW GASIFICATION PROCESS - Vereinigte Elektrizitätswerke Westfalen AG, Dortmund (C-600)

A gasification process being specially developed for application in power plants is the VEW Coal Conversion Process of Vereinigte Elektrizitätswerke Westfalen AG, a German utility. The process works on the principle of entrained flow. Coal is partly gasified with air and the remaining coke is burned separately in a combustion unit. Because the coal is only partly gasified, it is not necessary to use oxygen. A prototype 10 tons coal per hour plant has been operated in Gersteinwerk near Dortmund since 1985. Superheated steam of 530 degrees C and 180 bar is generated in the waste heat boiler. Two variants are being tested for gas cleaning, whereby both wet and dry gas cleaning are being applied. These consist of:
- Wet gas cleaning to remove chlorine and fluorine by forming ammonia salts; dry salts are produced in an evaporation plant
- Dry removal of chlorine and fluorine in a circulating fluidized bed in which lime is used as a reagent

The test operation was finished in January 1991.
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

The future concept of a coal-based combined cycle power plant links the partial coal gasification and the product gas cleaning with an innovative circulating fluidized bed combustor. In this process the product gas is freed only from dust, chlorine, and fluorine in order to protect the gas turbine materials. No reduction and sulfur removal is carried out in the combustor.

Project Cost: Not disclosed

VICTORIAN BROWN COAL LIQUEFACTION PROJECT – Brown Coal Liquefaction (Victoria) Pty. Ltd. (C-610)

BCLV was operating a pilot plant at Morwell in southeastern Victoria to process the equivalent of 50 tonnes per day of moist ash free coal until October 1990. BCLV is a subsidiary of the Japanese-owned Nippon Brown Coal Liquefaction Company (NBCL), a consortium involving Kobe Steel, Mitsubishi Kasei Corporation, Nissho Iwai, Idemitsu Kosan, and Cosmo Oil.

The project is being run as an inter-governmental cooperative project, involving the Federal Government of Australia, the State Government of Victoria, and the Government of Japan. The program is being fully funded by the Japanese government through the New Energy and Industrial Technology Development Organization (NEDO). NBCL is entrusted with implementation of the entire program, and BCLV is carrying out the Australian components. The Victorian government is providing the plant site, the coal, and some personnel.

Construction of the drying, slurrying, and primary hydrogenation sections comprising the first phase of the project began in November 1981. The remaining sections, consisting of solvent deashing and secondary hydrogenation, were completed during 1986. The pilot plant was operated until October 1990, and shut down at that point.

The pilot plant is located adjacent to the Morwell open cut brown coal mine. Davy McKee Pacific Pty. Ltd., provided the Australian portion of engineering design procurement and construction management of the pilot plant. The aim of the pilot plant was to prove the effectiveness of the BCL Process which had been developed since 1971 by the consortium.

Work at the BCLV plant was moved in 1990 to a Japanese laboratory, starting a three-year study that will determine whether a demonstration plant should be built. NBCL is developing a small laboratory in Kobe, Japan, specifically to study the Morwell project.

Part of the plant will be demolished and the Coal Corporation of Victoria is considering using a part of the plant for an R&D program aimed at developing more efficient brown coal technologies. The possibility of building a demonstration unit capable of producing 16,000 barrels per day from 5,000 tonnes per day of dry coal will be examined in Japan.

If a commercial plant were to be constructed, it would be capable of producing 100,000 barrels of synthetic oil, consisting of six lines of plant capable of producing 16,000 barrels from 5,000 tonnes per day dry coal. For this future stage, Australian companies will be called for equity participation for the project.

Project Cost: Approximately $700 million

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT – Destec Energy, Inc. and PSI Energy Inc. (C-614)

Located in West Terre Haute, Indiana, the project will repower one of the six units at PSI Energy’s Wabash River power station. The repowering scheme will use a single train, oxygen-blown Destec gasification plant and the existing steam turbine in a new integrated gasification combined cycle configuration to produce 265 megawatts of electricity from 2,500 tons per day of high sulfur eastern bituminous coal. The plant will be designed to substantially out-perform the standards established in the Clean Air Act Amendments for the year 2000. The demonstration period for the year 2000 will be approximately 3 years.

The $592 million project was selected for funding under Round 4 of the U.S. Department of Energy's (DOE) Clean Coal Technology Program, and is slated to begin commercial operation in 1995. DOE has agreed to fund 41% of the project cost.

Project Cost: $592 million

WESTERN CANADA IGCC DEMONSTRATION PLANT – Coal Association of Canada, Canadian Federal Government, the Provincial Governments of Alberta, Saskatchewan, Ontario and British Columbia (C-615)

A CS1 million feasibility study, led by the Coal Association of Canada and begun in 1990, has selected a 240 MW facility to be designed around a General Electric 7001 F gas turbine to test integrated gasification combined cycle technology in Western Canada. The demonstration will also be the first in the world to test carbon dioxide recovery. The study was completed in mid 1991. Two companies, Nova Scotia Power and Saskatchewan Power are now considering the results of the feasibility study to determine whether or not to go ahead with a siting study for the project.
COMMERCIAL AND R&D PROJECTS (Continued)

The project will incorporate a Shell entrained flow gasifier capable of using 2,400 tonnes per day of subbituminous coal and will also feature testing of a process that will recover 50 percent of the carbon dioxide from the gas stream prior to combustion. Capital cost is estimated around C$2,000/kW.

WESTERN ENERGY ADVANCED COAL CONVERSION PROCESS DEMONSTRATION – Rosebud SynCoal Partnership, Western Energy Company, United States Department of Energy (C-616)

The United States Department of Energy (DOE) signed an agreement with Western Energy Company for funding as a replacement project in Round 1 of the Department's Clean Coal Technology Program. DOE will fund half of the $69 million project and the partners will provide the other half of the funding. Western Energy Company has entered a partnership with Scotia Inc., a subsidiary of NRG, Northern States Powers' nonutility group. The new entity, Rosebud SynCoal Partnership will be the project owner. Western Energy Company has retained a contract to build and operate the facility.

The Western proposal is a novel coal cleaning process to improve the heating value and reduce the sulfur content of western coals. Typical western coals may contain moisture as much as 25 to 55 percent of their weight. The high moisture and mineral content of the coals reduces their heating value to less than 9,000 BTU per pound.

The Western Energy process would upgrade the coals, reducing their moisture content to as low as 1 percent and produce a heating value of up to 12,000 BTU per pound. The process also reduces sulfur content of the coals, which can be as high as 1.5 percent, to as low as 0.3 percent. The project will be conducted at a 50 ton per hour unit adjacent to a Western Energy subbituminous coal mine in Colstrip, Montana.

Construction of the ACCP demonstration facility is complete and initial “turnover” of equipment started in December 1991. The DOE agreement calls for a 3-year operation demonstrating the ability to produce a clean, high quality upgraded product and testing the product in utility and industrial applications.

Plant construction was completed ahead of schedule and, following shakedown activities, startup was achieved in early 1992. When in continuous operation, the plant will produce 1,000 tons per day, or 300,000 tons per year of upgraded solid fuel.

Northern States Power Company's Riverside plant will receive the first 5,000 ton shipment to conduct an initial test burn of the product. Dairyland Power has committed to use the next 5,000 tons for test burns at its Alma Station.

If demonstration is successful, Western Energy hopes to build a privately financed commercial-scale plant processing 1 to 3 million tons of coal per year by 1997.

Project Cost: $69 million

WUJING TRIGENERATION PROJECT – Shanghai Coking and Chemical Plant (C-620)

Shanghai Coking and Chemical Plant (SCCP) is planning a trigeneration project to produce coal-derived fuel gas, electricity, and steam. The proposed plant will be constructed near the Shanghai Coking and Chemical plant in Wujing, a suburb south of Shanghai. SCCP contracted with Bechtel on June 6, 1986 to conduct a technical and economic feasibility study of the project.

The project will consist of coal gasification facilities and other processing units to be installed and operated with the existing coke ovens in the Shanghai Coking and Chemical Plant. The facility will produce 2 million cubic meters per day of 3,800 Kcal per cubic meter of town gas; 70,000 kilowatt-hours of electricity per year; 100 metric tons per hour of low pressure steam; and 300,000 metric tons per year of 99.85 percent purity chemical grade methanol, 100,000 metric tons per year of acetic anhydride, and 50,000 metric tons per year of cellulose acetate. The project will be constructed in three phases.

In Phase 1, the production plan is further divided into 2 stages. In the first stage, 1 million cubic meters per day of town gas and 100,000 tons per year of methanol will be produced. The second stage will add another 0.7 million cubic meters per day of town gas and other 100,000 tons per year of methanol.

In November 1991, SCCP and Texaco Development Corporation signed an agreement for Texaco to furnish the gasifier, coal slurry and methanol systems. SCCP will import other advanced technologies and create foreign joint ventures at later stages for the production of acetic anhydride, formic acid, cellulose acetate and combined cycle power generation.

In March 1992, a foundation stone laying ceremony was performed at the plant site. Phase 1 is scheduled to be completed by June 1995.

Project Cost: 2 billion yuan
STATUS OF COAL PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL AND R&D PROJECTS (Continued)

YUNNAN LURGI CHEMICAL FERTILIZERS PLANT— Yunnan Province, China (C-625)

In the 1970s, a chemical fertilizer plant was set up in Yunnan province by using Lurgi pressurized gasifiers of 2.7 meter diameter. The pressurized gasification of a coal water slurry has completed a model test with a coal throughput of 20 kilograms per hour and achieved success in a pilot unit of 1.5 tons per hour. The carbon conversion reached 95 percent, with a cold gas efficiency of 66 percent.

For water-gas generation, coke was first used as feedstock. In the 1950s, experiments of using anthracite to replace coke were successful, thus reducing the production cost of ammonia by 25 to 30 percent. In order to substitute coal briquettes for lump anthracite, the Beijing Research Institute of Coal Chemistry developed a coal briquetting process in which humate was used as a binder to produce synthetic gas for chemical fertilizer production. This process has been applied to production.

YUNNAN PROVINCE COAL GASIFICATION PLANT — People's Republic of China (C-630)

China is building a coal gasification plant in Kunming, Yunnan Province, that will produce about 220,000 cubic meters of coalgas per day. Joe Ng Engineering of Ontario, Canada has been contracted to design and equip the plant with the help of a $5 million loan from the Canadian Export Development Corporation.
<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-C Valley Corporation Project</td>
<td>A-C Valley Corporation</td>
<td>June 1984; page 4-59</td>
</tr>
<tr>
<td>Acurex-Aerotherm Low-BTU Gasifier for Commercial Use</td>
<td>Acurex-Aerotherm Corporation, Glen-Gery Corporation, United States Department of Energy</td>
<td>September 1981; page 4-52</td>
</tr>
<tr>
<td>Agglomerating Burner Project</td>
<td>Battelle Memorial Institute, United States Department of Energy</td>
<td>September 1978; page B-22</td>
</tr>
<tr>
<td>Air Products Slagging Gasifier Project</td>
<td>Air Products and Chemicals, Inc.</td>
<td>September 1985; page 4-61</td>
</tr>
<tr>
<td>Alabama Synthetic Fuels Project</td>
<td>AMTAR Inc., Applied Energetics Inc.</td>
<td>June 1984; page 4-60</td>
</tr>
<tr>
<td>Amax Coal Gasification Plant</td>
<td>AMAX, Inc.</td>
<td>March 1983; page 4-85</td>
</tr>
<tr>
<td>Appalachian Project</td>
<td>M. W. Kellogg Co., United States Department of Energy</td>
<td>September 1989; page 4-53</td>
</tr>
<tr>
<td>Arkansas Lignite Conversion Project</td>
<td>Dow Chemical Company, Elecere Inc., International Paper Company</td>
<td>December 1984; page 4-64</td>
</tr>
<tr>
<td>Australian SRC Project</td>
<td>CSR Ltd., Mitsui Coal Development Pty, Ltd.</td>
<td>September 1985; page 4-62</td>
</tr>
<tr>
<td>Beach-Wibaux Project</td>
<td>See Tenneco SNG from Coal</td>
<td></td>
</tr>
<tr>
<td>Beacon Process</td>
<td>Standard Oil Company (Ohio), TRW, Inc.</td>
<td>March 1985; page 4-62</td>
</tr>
<tr>
<td>Bell High Mass Flux Gasifier</td>
<td>Bell Aerospace Textron, Gas Research Institute, United States Department of Energy</td>
<td>December 1981; page 4-72</td>
</tr>
<tr>
<td>Beluga Methanol Project</td>
<td>Cook Inlet Region, Inc., Placer U. S. Inc.</td>
<td>December 1983; page 4-77</td>
</tr>
<tr>
<td>BI-GAS Project</td>
<td>United States Department of Energy</td>
<td>March 1985; page 4-63</td>
</tr>
<tr>
<td>Breckinridge Project</td>
<td>Bechtel Petroleum, Inc.</td>
<td>December 1983; page 4-78</td>
</tr>
<tr>
<td>BRICC Coal Liquefaction Program</td>
<td>Beijing Research Institute of Coal Chemistry</td>
<td>March 1992; page 4-50</td>
</tr>
<tr>
<td>Burnham Coal Gasification Project</td>
<td>El Paso Natural Gas Company</td>
<td>September 1983; page 4-62</td>
</tr>
<tr>
<td>Byrne Creek Underground Coal Gasification</td>
<td>Dravo Constructors, World Energy Inc.</td>
<td>March 1987; page 4-90</td>
</tr>
<tr>
<td>Calderon Fixed-Bed Slagging Project</td>
<td>Calderon Energy Company</td>
<td>December 1985; page 4-73</td>
</tr>
<tr>
<td>Project</td>
<td>Sponsors</td>
<td>Last Appearance in SFR</td>
</tr>
<tr>
<td>---------------------------------------------</td>
<td>--------------------------------------------------------------------------</td>
<td>------------------------</td>
</tr>
<tr>
<td>Car-Mox Low-BTU Gasification Project</td>
<td>Fike Chemicals, Inc.</td>
<td>March 1980; page 4-53</td>
</tr>
<tr>
<td>Catalytic Coal Liquefaction</td>
<td>Gulf Research and Development</td>
<td>December 1978; page B-25</td>
</tr>
<tr>
<td>Caterpillar Low BTU Gas From Coal</td>
<td>Caterpillar Tractor Company</td>
<td>September 1988; page 4-55</td>
</tr>
<tr>
<td>Celanese Coastal Bend Project</td>
<td>Celanese Corporation</td>
<td>December 1982; page 4-83</td>
</tr>
<tr>
<td>Celanese East Texas Project</td>
<td>Celanese Corporation</td>
<td>December 1982; page 4-83</td>
</tr>
<tr>
<td>Central Arkansas Energy Project</td>
<td>Arkansas Power &amp; Light Company</td>
<td>June 1984; page 4-63</td>
</tr>
<tr>
<td>Sears Island Project</td>
<td>Central &amp; Southwest Corporation (four utility companies)</td>
<td>December 1983; page 4-80</td>
</tr>
<tr>
<td>Chemicals from Coal</td>
<td>Dow Chemical USA United States Department of Energy</td>
<td>March 1978; page B-24</td>
</tr>
<tr>
<td>Chiriqui Grande Project</td>
<td>Ebasco Services, Inc. United States State Department (Trade &amp; Development)</td>
<td>June 1987; page 4-51</td>
</tr>
<tr>
<td>Chokecherry Project</td>
<td>Energy Transition Corporation</td>
<td>December 1983; page 4-81</td>
</tr>
<tr>
<td>Circle West Project</td>
<td>Meridian Minerals Company</td>
<td>September 1986; page 4-58</td>
</tr>
<tr>
<td>Clark Synthesis Gas Project</td>
<td>Clark Oil and Refining Corporation</td>
<td>December 1982; page 4-85</td>
</tr>
<tr>
<td>Clean Coke Project</td>
<td>United States Department of Energy U.S. Steel USS Engineers and Consultants, Inc.</td>
<td>December 1978; page B-26</td>
</tr>
<tr>
<td>Coalcon Project</td>
<td>Union Carbide Corporation</td>
<td>December 1978; page B-26</td>
</tr>
<tr>
<td>Coalex Process Development</td>
<td>Coalex Energy</td>
<td>December 1978; page B-26</td>
</tr>
<tr>
<td>COGAS Process Development</td>
<td>COGAS Development Company, a joint venture of: Consolidated Gas Supply Corporation FMC Corporation Panhandle Eastern Pipeline Company Tennessee Gas Pipeline Company</td>
<td>December 1982; page 4-86</td>
</tr>
</tbody>
</table>
### Status of Coal Projects

#### Completed and Suspended Projects (Continued)

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Columbia Coal Gasification Project</td>
<td>Rosebud Energy Corporation</td>
<td>September 1982; page 4-72</td>
</tr>
<tr>
<td>Combined Cycle Coal Gasification</td>
<td>Columbia Gas System, Inc.</td>
<td>December 1982; page 4-86</td>
</tr>
<tr>
<td>Energy Centers</td>
<td>Consumer Energy Corporation</td>
<td></td>
</tr>
<tr>
<td>Composite Gasifier Project</td>
<td>British Gas Corporation, British Department of Energy</td>
<td>September 1981; page 4-56</td>
</tr>
<tr>
<td>Corex Iron Making Process</td>
<td>Korf Engineering</td>
<td>March 1990; page 4-51</td>
</tr>
<tr>
<td>Cresap Liquid Fuels Plant</td>
<td>Fluor Engineers and Constructors, United States Department of Energy</td>
<td>December 1979; page 4-67</td>
</tr>
<tr>
<td>Crow Indian Coal Gasification Project</td>
<td>Crow Indian Tribe, United States Department of Energy</td>
<td>December 1983; page 4-84</td>
</tr>
<tr>
<td>Crow Indian Coal-to-Gasoline Project</td>
<td>Crow Indian Tribe, TransWorld Resources</td>
<td>September 1984; page C-8</td>
</tr>
<tr>
<td>Danish Gasification Combined Project</td>
<td>Elkraft</td>
<td>December 1991; page 4-75</td>
</tr>
<tr>
<td>DeSota County, Mississippi Coal Project</td>
<td>Mississippi Power and Light, Mississippi, State of Ralph M. Parsons Company</td>
<td>September 1981; page 4-58</td>
</tr>
<tr>
<td>Dow Coal Liquefaction Process</td>
<td>Dow Chemical Company</td>
<td>December 1984; page 4-70</td>
</tr>
<tr>
<td>Development</td>
<td>Dow Chemical Company</td>
<td>June 1987; page 4-53</td>
</tr>
<tr>
<td>Dow Gasification Process Development</td>
<td>Dow Chemical Company</td>
<td>June 1985; page 4-63</td>
</tr>
<tr>
<td>Project</td>
<td>Sponsors</td>
<td>Last Appearance in SFR</td>
</tr>
<tr>
<td>---------------------------------------</td>
<td>--------------------------------------------------------------------------</td>
<td>------------------------</td>
</tr>
<tr>
<td>Elmwood Coal-Water-Fuel Project</td>
<td>Foster Wheeler Tennessee</td>
<td>March 1987; page 4-66</td>
</tr>
<tr>
<td>Emery Coal Conversion Project</td>
<td>Emery Synfuels Associates: Mountain Fuel Supply Company</td>
<td>December 1983; page 4-84</td>
</tr>
<tr>
<td>Enrecon Coal Gasifier</td>
<td>Enrecon, Inc.</td>
<td>September 1985; page 4-66</td>
</tr>
<tr>
<td>Escrick Cyclone Gasifier Test</td>
<td>Oaklands Limited</td>
<td>March 1991; page 4-81</td>
</tr>
<tr>
<td>Exxon Catalytic Gasification</td>
<td>Exxon Company USA</td>
<td>December 1984; page 4-73</td>
</tr>
<tr>
<td>Process Development</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fairmont Lamp Division Project</td>
<td>Westinghouse Electric Corporation</td>
<td>September 1982; page 4-76</td>
</tr>
<tr>
<td>Fast Fluid Bed Gasification</td>
<td>Hydrocarbon Research, Inc.</td>
<td>December 1982; page 4-90</td>
</tr>
<tr>
<td>Fiat/Ansaldo Project</td>
<td>Ansaldo, Fiat TTG, KRW Energy Systems, Inc.</td>
<td>March 1985; page 4-66</td>
</tr>
<tr>
<td>Fast Pyrolysis Coal Conversion</td>
<td>Occidental Research Corporation, United States Department of Energy</td>
<td>December 1982; page 4-91</td>
</tr>
<tr>
<td>Flash Pyrolysis of Coal</td>
<td>Brookhaven National Laboratory</td>
<td>June 1988; page 4-69</td>
</tr>
<tr>
<td>Florida Power Combined Cycle Project</td>
<td>Florida Power Corporation, United States Department of Energy</td>
<td>December 1983; page 4-87</td>
</tr>
<tr>
<td>Fuel Gas Demonstration Plant Program</td>
<td>Foster-Wheeler Energy Corporation, United States Department of Energy</td>
<td>September 1980; page 4-68</td>
</tr>
<tr>
<td>Fulaiji Low-BTU Gasifier</td>
<td>M.W. Kellogg Company, People's Republic of China</td>
<td>December 1988; page 4-59</td>
</tr>
<tr>
<td>Gas Turbine Systems Development</td>
<td>Curtis-Wright Corporation, United States Department of Energy, General Electric Company</td>
<td>December 1983; page 4-87</td>
</tr>
<tr>
<td>Grants Coal to Methanol Project</td>
<td>Energy Transition Corporation</td>
<td>December 1983; page 4-89</td>
</tr>
<tr>
<td>Greek Lignite Gasification Project</td>
<td>Nitrogenous Fertilizer Industry (AEVAL)</td>
<td>September 1988; page 4-61</td>
</tr>
<tr>
<td>Greenco Low-BTU Project</td>
<td>General Refractories Company, United States Department of Energy</td>
<td>December 1983; page 4-91</td>
</tr>
<tr>
<td>GSP Pilot Plant Project</td>
<td>German Democratic Republic</td>
<td>December 1991; page 4-80</td>
</tr>
<tr>
<td>Gulf States Utilities Project</td>
<td>KRW Energy Systems, Gulf States Utilities</td>
<td>March 1985, page 4-74</td>
</tr>
<tr>
<td>Hampshire Gasoline Project</td>
<td>Kaneb Services, Koppers Company, Metropolitan Life Insurance Company, Northwestern Mutual Life Insurance</td>
<td>December 1983; page 4-91</td>
</tr>
<tr>
<td>Hanover Energy Doswell Project</td>
<td>Doswell Limited Partnership</td>
<td>March 1991; page 4-84</td>
</tr>
<tr>
<td>H-Coal Pilot Plant</td>
<td>Ashland Synthetic Fuels, Inc.</td>
<td>December 1983; page 4-92</td>
</tr>
</tbody>
</table>
### STATUS OF COAL PROJECTS

#### COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hillsborough Bay Coal-Water Fuel Project</td>
<td>ARC-Coal Inc.</td>
<td>September 1985; page 4-69</td>
</tr>
<tr>
<td></td>
<td>Bechtel Power Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>COMCO of America, Inc.</td>
<td></td>
</tr>
<tr>
<td>Howmet Aluminum</td>
<td>Howmet Aluminum Corporation</td>
<td>March 1985; page 4-74</td>
</tr>
<tr>
<td></td>
<td>The Slagging Gasification Consortium</td>
<td></td>
</tr>
<tr>
<td>Huenxe CGT Coal Gasification Pilot Plant</td>
<td>Carbon Gas Technology (CGT) GmbH</td>
<td>March 1991; page 4-85</td>
</tr>
<tr>
<td>Hydrogen from Coal</td>
<td>Air Products and Chemicals, Inc.</td>
<td>December 1978; page B-31</td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>HYGAS Pilot Plant Project</td>
<td>Gas Research Institute</td>
<td>December 1980; page 4-86</td>
</tr>
<tr>
<td></td>
<td>Institute of Gas Technology</td>
<td></td>
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<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
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<tr>
<td>ICGG Pipeline Gas Demonstration Plant Project</td>
<td>Illinois Coal Gasification Group</td>
<td>September 1981; page 4-66</td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Integrated Two-Stage Liquefaction</td>
<td>Cities Service/Lummus</td>
<td>September 1986; page 4-69</td>
</tr>
<tr>
<td>ITT Coal to Gasoline Plant</td>
<td>International Telephone &amp; Telegraph</td>
<td>December 1981; page 4-93</td>
</tr>
<tr>
<td></td>
<td>J. W. Miller</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Kaiparowits Project</td>
<td>Arizona Public Service</td>
<td>March 1978; page B-18</td>
</tr>
<tr>
<td></td>
<td>San Diego Gas and Electric</td>
<td></td>
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<tr>
<td></td>
<td>Southern California Edison</td>
<td></td>
</tr>
<tr>
<td>Kansk-Achinsk Basin Coal Liquefaction Pilot Plant</td>
<td>Union of Soviet Socialist Republics</td>
<td>March 1992; page 4-82</td>
</tr>
<tr>
<td>Kennedy Space Center Polygeneration Project</td>
<td>National Aeronautics &amp; Space Administration</td>
<td>June 1986; page 4-85</td>
</tr>
<tr>
<td>Ken-Tex Project</td>
<td>Texas Gas Transmission Corporation</td>
<td>December 1983; page 4-95</td>
</tr>
<tr>
<td>Keystone Project</td>
<td>The Signal Companies</td>
<td>September 1986; page 4-71</td>
</tr>
<tr>
<td>King-Wilkinson/Hoffman Project</td>
<td>E. J. Hoffman</td>
<td>March 1985; page 4-80</td>
</tr>
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<td></td>
<td>King-Wilkinson, Inc.</td>
<td></td>
</tr>
<tr>
<td>KILnGAS Project</td>
<td>Allis-Chalmers</td>
<td>December 1988; page 4-65</td>
</tr>
<tr>
<td></td>
<td>State of Illinois</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
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<td>Central Illinois Light Company</td>
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<td>Electric Power Research Institute</td>
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<td>Illinois Power Company</td>
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<td></td>
<td>Ohio Edison Company</td>
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</tbody>
</table>
### STATUS OF COAL PROJECTS

#### COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Klockner Coal Gasifier</td>
<td>Klockner Kohlegas, CRA (Australia)</td>
<td>March 1987; page 4-74</td>
</tr>
<tr>
<td>Kohle Iron Reduction Process</td>
<td>Weirton Steel Corp, U.S. Department of Energy</td>
<td>December 1987; page 4-75</td>
</tr>
<tr>
<td>Coal Gasification System for</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electric Power Generation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lake DeSmet SNG from Coal Project</td>
<td>Texaco Inc., Transwestern Coal Gasification Company</td>
<td>December 1982; page 4-98</td>
</tr>
<tr>
<td></td>
<td>Research Institute, U.S. Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Latrobe Valley Coal Liquefaction Project</td>
<td>Rheinische Braunkohlwewerke AG</td>
<td>December 1983; page 4-96</td>
</tr>
<tr>
<td>LC-Fining Processing of SRC</td>
<td>Cities Service Company, United States Department of Energy</td>
<td>December 1983; page 4-96</td>
</tr>
<tr>
<td>LIBIAZ Coal-To-Methanol Project</td>
<td>Krupp Koppers, KOPEX</td>
<td>December 1988; page 4-65</td>
</tr>
<tr>
<td>Liquefaction of Alberta</td>
<td>Alberta/Canada Energy Resources Research Fund, Alberta Research Council</td>
<td>March 1985, page 4-81</td>
</tr>
<tr>
<td>Subbituminous Coals, Canada</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low/Medium-BTU Gas for Multi-Company Steel Complex</td>
<td>Bethlehem Steel Company, Inland Steel Company, Jones &amp; Laughlin Steel Company, National Steel Company, Northern Indiana Public Service Company, Union Carbide Corporation</td>
<td>December 1983; page 4-98</td>
</tr>
<tr>
<td>Low-Rank Coal Liquefaction Project</td>
<td>United States Department of Energy, University of North Dakota</td>
<td>March 1984; page 4-49</td>
</tr>
<tr>
<td>Lulea Molten Iron Gasification Pilot Plant</td>
<td>KHD Humbolt Wedag AG and Sumitomo Metal Industries, Ltd.</td>
<td>March 1991; page 4-90</td>
</tr>
<tr>
<td>Lummus Coal Liquefaction Development</td>
<td>Lummus Company, United States Department of Energy</td>
<td>June 1981; page 4-74</td>
</tr>
<tr>
<td>Mapco Coal-to-Methanol Project</td>
<td>Mapco Synfuels</td>
<td>December 1983; page 4-98</td>
</tr>
<tr>
<td>Mazingarbe Coal Gasification Project</td>
<td>Cerchar (France), European Economic Community Gas Development Corporation, Institute of Gas Technology</td>
<td>September 1985, page 4-73</td>
</tr>
<tr>
<td>Medium-BTU Gas Project</td>
<td>Columbia Coal Gasification</td>
<td>September 1979; page 4-107</td>
</tr>
<tr>
<td>Medium-BTU Gasification Project</td>
<td>Houston Natural Gas Corporation</td>
<td>December 1983; page 4-99</td>
</tr>
</tbody>
</table>
## STATUS OF COAL PROJECTS

### COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Memphis Industrial Fuel Gas Project</td>
<td>Texaco Inc. CBI Industries Inc. Givex Corporation Foster Wheeler Corporation Great Lakes International Houston Natural Gas Corporation Ingersoll-Rand Company Memphis Light, Gas &amp; Water Division</td>
<td>June 1984; page 4-79</td>
</tr>
<tr>
<td>Methanol from Coal</td>
<td>UGI Corporation</td>
<td>March 1978; page B-22</td>
</tr>
<tr>
<td>Methanol from Coal</td>
<td>Wentworth Brothers, Inc. (19 utility and industrial sponsors)</td>
<td>March 1980; page 4-58</td>
</tr>
<tr>
<td>Midrex Electrothermal Direct Reduction Process</td>
<td>Georgetown Texas Steel Corporation Midrex Corporation</td>
<td>September 1982; page 4-87</td>
</tr>
<tr>
<td>Millmerran Coal Liquefaction</td>
<td>Australian Coal Corporation</td>
<td>March 1985; page 4-82</td>
</tr>
<tr>
<td>Minnegasco High-BTU Gas from Peat</td>
<td>Minnesota Gas Company United States Department of Energy</td>
<td>March 1983; page 4-108</td>
</tr>
<tr>
<td>Minnegasco Peat Biogasification Project</td>
<td>Minnesota Gas Company Northern Natural Gas Company United States Department of Energy</td>
<td>December 1981; page 4-88</td>
</tr>
<tr>
<td>Minnegasco Peat Gasification Project</td>
<td>Gas Research Institute Institute of Gas Technology Minnesota Gas Company Northern Natural Gas Company United States Department of Energy</td>
<td>December 1983; page 4-101</td>
</tr>
<tr>
<td>Minnesota Power ELFUEL Project</td>
<td>Minnesota Power &amp; Light BNI Coal Institute of Gas Technology Electric Power Research Institute Bechtel Corporation</td>
<td>June 1991; page 4-82</td>
</tr>
</tbody>
</table>
### STATUS OF COAL PROJECTS

#### COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mobil-M Project</td>
<td>Mobil Oil Company</td>
<td>September 1982; page 4-88</td>
</tr>
<tr>
<td>Molten Salt Process Development</td>
<td>Rockwell International</td>
<td>December 1983; page 4-101</td>
</tr>
<tr>
<td>Mountain Fuel Coal Gasification Process</td>
<td>Mountain Fuel Resources</td>
<td>September 1988; page 4-67</td>
</tr>
<tr>
<td>Mulberry Coal-Water Fuel Project</td>
<td>CoalLiquid, Inc.</td>
<td>March 1985; page 4-85</td>
</tr>
<tr>
<td>NASA Lewis Research Center Coal-to-Gas Polygeneration Power Plant</td>
<td>NASA Lewis Research Center</td>
<td>December 1983; page 4-102</td>
</tr>
<tr>
<td>National Synfuels Project</td>
<td>Elgin Butler Brick Company</td>
<td>September 1988; page 4-67</td>
</tr>
<tr>
<td>New England Energy Park</td>
<td>Bechtel Power Corporation</td>
<td>December 1983; page 4-104</td>
</tr>
<tr>
<td>New Jersey Coal-Water Fuel Project</td>
<td>Ashland Oil, Inc.</td>
<td>March 1985; page 4-86</td>
</tr>
<tr>
<td>New Mexico Coal Pyrolysis Project</td>
<td>Energy Transition Corporation</td>
<td>September 1988; page 4-67</td>
</tr>
<tr>
<td>Nices Project</td>
<td>Northwest Pipeline Corporation</td>
<td>December 1983; page 4-104</td>
</tr>
<tr>
<td>North Alabama Coal to Methanol Project</td>
<td>Air Products &amp; Chemicals Company</td>
<td>March 1985; page 4-86</td>
</tr>
<tr>
<td>North Dakota Synthetic Fuels Project</td>
<td>InterNorth</td>
<td>December 1983; page 4-106</td>
</tr>
<tr>
<td>NYNAS Energy Chemicals Complex</td>
<td>AGA</td>
<td>December 1990; page 4-76</td>
</tr>
<tr>
<td>Oberhausen Coal Gasification Project</td>
<td>A. Johnson &amp; Company</td>
<td>September 1986; page 4-79</td>
</tr>
<tr>
<td>Ohio I Coal Conversion</td>
<td>Alberta Gas Chemicals, Inc.</td>
<td>March 1985; page 4-88</td>
</tr>
<tr>
<td>Ohio I Coal Conversion Project</td>
<td>Energy Adaptors Corporation</td>
<td>March 1990; page 4-65</td>
</tr>
</tbody>
</table>
STATUS OF COAL PROJECTS

COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ohio Coal/Oil Coprocessing Project</td>
<td>Ohio Clean Fuels, Inc.</td>
<td>June 1991; page 4-84</td>
</tr>
<tr>
<td></td>
<td>Stone and Webster Engineering Corp.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>HRI Inc.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ohio Coal Development Office</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Ohio Valley Synthetic Fuels Project</td>
<td>Consolidated Natural Gas System</td>
<td>March 1982; page 4-68</td>
</tr>
<tr>
<td></td>
<td>Standard Oil Company of Ohio</td>
<td></td>
</tr>
<tr>
<td>Ott Hydrogenation Process Project</td>
<td>Carl A. Ott Engineering Company</td>
<td>December 1983; page 4-107</td>
</tr>
<tr>
<td>Peat-by-Wire Project</td>
<td>PBW Corporation</td>
<td>March 1985; page 4-89</td>
</tr>
<tr>
<td>Peat Methanol Associates Project</td>
<td>ETCO Methanol Inc.</td>
<td>June 1984; page 4-85</td>
</tr>
<tr>
<td></td>
<td>J. B. Sunderland</td>
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</tr>
<tr>
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<td>Peat Methanol Associates</td>
<td></td>
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<tr>
<td></td>
<td>Transco Peat Methanol Company</td>
<td></td>
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<tr>
<td>Penn/Sharon/Klockner Project</td>
<td>Klockner Kohlegas GmbH</td>
<td>March 1985; page 4-72</td>
</tr>
<tr>
<td></td>
<td>Pennsylvania Engineering Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sharon Steel Corporation</td>
<td></td>
</tr>
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<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Phillips Coal Gasification Project</td>
<td>Phillips Coal Company</td>
<td>September 1984; page C-28</td>
</tr>
<tr>
<td>Pike County Low-BTU Gasifier for Commercial Use</td>
<td>Appalachian Regional Commission</td>
<td>June 1981; page 4-78</td>
</tr>
<tr>
<td></td>
<td>Kentucky, Commonwealth of</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Plasma Arc Torch Corporation</td>
<td>Swindell-Dresser Company</td>
<td>December 1978; page B-33</td>
</tr>
<tr>
<td></td>
<td>Technology Application Service</td>
<td></td>
</tr>
<tr>
<td>Port Sutton Coal-Water Fuel Project</td>
<td>ARC-Coal, Inc.</td>
<td>December 1985; page 4-86</td>
</tr>
<tr>
<td></td>
<td>COMCO of America, Inc.</td>
<td></td>
</tr>
<tr>
<td>Powerton Project</td>
<td>Commonwealth Edison</td>
<td>March 1979; page 4-86</td>
</tr>
<tr>
<td></td>
<td>Electric Power Research Institute</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Fluor Engineers and Constructors</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Illinois, State of</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Purged Carbons Project</td>
<td>Integrated Carbons Corporation</td>
<td>December 1983; page 4-108</td>
</tr>
<tr>
<td>Pyrolysis Demonstration Plant</td>
<td>Kentucky, Commonwealth of</td>
<td>December 1978; page B-34</td>
</tr>
<tr>
<td></td>
<td>Occidental Research Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tennessee Valley Authority</td>
<td></td>
</tr>
<tr>
<td>Pyrolysis of Alberta Thermal Coals, Canada</td>
<td>Alberta/Canada Energy Resource Research Fund</td>
<td>March 1985; page 4-90</td>
</tr>
<tr>
<td></td>
<td>Alberta Research Council</td>
<td></td>
</tr>
<tr>
<td>Riser Cracking of Coal</td>
<td>Institute of Gas Technology</td>
<td>December 1981; page 4-93</td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>RUHR100 Project</td>
<td>Ruhrgas AG</td>
<td>September 1984; page C-29</td>
</tr>
<tr>
<td></td>
<td>Ruhrkohle AG</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Steag AG</td>
<td></td>
</tr>
<tr>
<td></td>
<td>West German Ministry of Research and Technology</td>
<td></td>
</tr>
<tr>
<td>Project</td>
<td>Sponsors</td>
<td>Last Appearance in SFR</td>
</tr>
<tr>
<td>-----------------------------------------------------</td>
<td>--------------------------------------------------------------------------</td>
<td>---------------------------------</td>
</tr>
<tr>
<td>Rheinbraun Hydrogasification of Coal</td>
<td>Reinische Braunkohlenwerke</td>
<td>December 1987; page 4-80</td>
</tr>
<tr>
<td></td>
<td>Lurgi GmbH</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ministry of Research &amp; Technology</td>
<td></td>
</tr>
<tr>
<td>Saarbergwerke-Otto Gasification Process</td>
<td>Saarbergwerke AG</td>
<td>June 1984; page 4-86</td>
</tr>
<tr>
<td></td>
<td>Dr. C. Otto &amp; Company</td>
<td></td>
</tr>
<tr>
<td>Savannah Coal-Water Fuel Projects</td>
<td>Foster Wheeler Corporation</td>
<td>September 1985; page 4-77</td>
</tr>
<tr>
<td>Scrubgrass Project</td>
<td>Scrubgrass Associates</td>
<td>March 1990; page 4-69</td>
</tr>
<tr>
<td>Sesco Project</td>
<td>Solid Energy Systems Corporation</td>
<td>December 1983; page 4-110</td>
</tr>
<tr>
<td>Sharon Steel</td>
<td>Klockner Kohlegas GmbH</td>
<td>March 1985; page 4-92</td>
</tr>
<tr>
<td></td>
<td>Pennsylvania Engineering Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sharon Steel Corporation</td>
<td></td>
</tr>
<tr>
<td>Shell Coal Gasification Project</td>
<td>Shell Oil Company</td>
<td>June 1991; page 4-89</td>
</tr>
<tr>
<td></td>
<td>Royal Dutch/Shell Group</td>
<td></td>
</tr>
<tr>
<td>Simplified IGCC Demonstration Project</td>
<td>General Electric Company</td>
<td>September 1986; page 4-71</td>
</tr>
<tr>
<td></td>
<td>Burlington Northern Railroad</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Empire State Electric Energy Research Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>New York State Energy Research and Development Authority</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Niagara Mohawk Power Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ohio Department of Development</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Peabody Holding Company</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Slagging Gasification Consortium Project</td>
<td>Babcock Woodall-Duckham Ltd.</td>
<td>September 1985; page 4-78</td>
</tr>
<tr>
<td></td>
<td>Big Three Industries, Inc.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>The BOC Group plc</td>
<td></td>
</tr>
<tr>
<td></td>
<td>British Gas Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Consolidation Coal Company</td>
<td></td>
</tr>
<tr>
<td>Sohio Lima Coal Gasification/Ammonia Plant Retrofit Project</td>
<td>Sohio Alternate Energy Development Company</td>
<td>March 1985; page 4-93</td>
</tr>
<tr>
<td>Solution-Hydrogasification Process Development</td>
<td>General Atomic Company</td>
<td>September 1978; page B-31</td>
</tr>
<tr>
<td></td>
<td>Stone &amp; Webster Engineering Company</td>
<td></td>
</tr>
<tr>
<td>Southern California Synthetic Fuels Energy System</td>
<td>C. F. Braun</td>
<td>March 1981; page 4-99</td>
</tr>
<tr>
<td></td>
<td>Pacific Lighting Corporation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Southern California Edison Company</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Texaco Inc.</td>
<td></td>
</tr>
<tr>
<td>Solvent Refined Coal Demonstration Plant</td>
<td>International Coal Refining Company</td>
<td>September 1986; page 4-83</td>
</tr>
<tr>
<td></td>
<td>Air Products and Chemicals Inc.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Kentucky Energy Cabinet</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Wheelabrator-Frye Inc.</td>
<td></td>
</tr>
<tr>
<td>Steam-Iron Project</td>
<td>Gas Research Institute</td>
<td>December 1978; page B-35</td>
</tr>
<tr>
<td></td>
<td>Institute of Gas Technology</td>
<td></td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Synthane Project</td>
<td>United States Department of Energy</td>
<td>December 1978; page B-35</td>
</tr>
<tr>
<td>Synthoil Project</td>
<td>Foster Wheeler Energy Corporation</td>
<td>December 1978; page B-36</td>
</tr>
<tr>
<td></td>
<td>United States Department of Energy</td>
<td></td>
</tr>
<tr>
<td>Project</td>
<td>Sponsors</td>
<td>Last Appearance in SFR</td>
</tr>
<tr>
<td>----------------------------------------</td>
<td>--------------------------------------------------------------------------</td>
<td>----------------------------------------------</td>
</tr>
<tr>
<td>Sweeny Coal-to-Fuel Gas Project</td>
<td>The Signal Companies, Inc.</td>
<td>March 1985; page 4-94</td>
</tr>
<tr>
<td>Tenneco SNG From Coal</td>
<td>Tenneco Coal Company</td>
<td>March 1987; page 4-85</td>
</tr>
<tr>
<td>Mobil-M Plant</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Toscoal Process Development</td>
<td>TOSCO Corporation</td>
<td>September 1988; page 4-72</td>
</tr>
<tr>
<td>Transco Coal Gas Plant</td>
<td>Transco Energy Company</td>
<td>December 1983; page 4-113</td>
</tr>
<tr>
<td>Tri-State Project</td>
<td>Kentucky Department of Energy, Texas Eastern Corporation, Texas Gas Transmission Corporation, United States Department of Energy</td>
<td>December 1983; page 4-113</td>
</tr>
<tr>
<td>TRW Coal Gasification Process</td>
<td>TRW, Inc.</td>
<td>December 1983; page 4-114</td>
</tr>
<tr>
<td>TVA Ammonia From Coal Project</td>
<td>Tennessee Valley Authority</td>
<td>September 1989; page 4-77</td>
</tr>
<tr>
<td>Two-Stage Entrained Gasification System</td>
<td>Combustion Engineering Inc., Electric Power Research Institute, United States Department of Energy</td>
<td>June 1984; page 4-91</td>
</tr>
<tr>
<td>Underground Bituminous Coal Gasification</td>
<td>Morgantown Energy Technology Center</td>
<td>March 1987; page 4-93</td>
</tr>
<tr>
<td>Underground Coal Gasification</td>
<td>United States Department of Energy, University of Texas</td>
<td>June 1985; page 4-75</td>
</tr>
<tr>
<td>Underground Coal Gasification, Ammonia/Urea Project</td>
<td>Energy International</td>
<td>March 1990; page 4-76</td>
</tr>
<tr>
<td>Underground Gasification of Anthracite, Spruce Creek</td>
<td>Spruce Creek Energy Company</td>
<td>March 1990; page 4-76</td>
</tr>
<tr>
<td>Underground Coal Gasification, Joint Belgo-German Project</td>
<td>Government of Belgium</td>
<td>March 1990; page 4-74</td>
</tr>
<tr>
<td>UCG Brazil</td>
<td>Companhia Auxiliar de Empresas Electricas Brasileiras</td>
<td>September 1988; Page 4-75</td>
</tr>
<tr>
<td>UCG Brazil</td>
<td>Companhia Auxiliar de Empresas Electricas Brasileiras, U.S. DOE</td>
<td>December 1988; page 4-25</td>
</tr>
<tr>
<td>Underground Coal Gasification, Canada</td>
<td>Alberta Research Council</td>
<td>September 1984; page C-37</td>
</tr>
<tr>
<td>Underground Coal Gasification, English Midlands Pilot Project</td>
<td>British Coal</td>
<td>September 1987; page 4-76</td>
</tr>
<tr>
<td>Underground Coal Gasification, Hanna Project</td>
<td>Rocky Mountain Energy Company, United States Department of Energy</td>
<td>June 1985; page 4-75</td>
</tr>
<tr>
<td>Underground Coal Gasification, Leigh Creek</td>
<td>Government of South Australia</td>
<td>September 1989; page 4-81</td>
</tr>
</tbody>
</table>
### STATUS OF COAL PROJECTS

#### COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SFR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Underground Coal Gasification Hoe Creek Project</td>
<td>Lawrence Livermore National Laboratory United States Department of Energy</td>
<td>December 1983; page 4-119</td>
</tr>
<tr>
<td>Underground Coal Gasification LLNL Studies</td>
<td>Lawrence Livermore National Laboratory</td>
<td>December 1990; page 4-84</td>
</tr>
<tr>
<td>Underground Coal Gasification</td>
<td>Mitchell Energy Republic of Texas Coal Company</td>
<td>March 1985; page 4-98</td>
</tr>
<tr>
<td>Underground Coal Gasification Rocky Hill Project</td>
<td>ARCO</td>
<td>December 1983; page 4-120</td>
</tr>
<tr>
<td>Underground Coal Gasification, Rocky Mountain I Test</td>
<td>Amoco Production Company</td>
<td>March 1990; page 4-76</td>
</tr>
<tr>
<td>Underground Gasification of Deep Seams</td>
<td>Groupe d'Etudes de la Gazéification Souterraine Charbonnages de France Gaz de France Institut Français du Petrole</td>
<td>December 1987; page 4-86</td>
</tr>
<tr>
<td>Underground Gasification of Texas Lignite, Tennessee Colony Project</td>
<td>Basic Resources, Inc.</td>
<td>December 1983; page 4-121</td>
</tr>
<tr>
<td>Underground Gasification of Texas Lignite</td>
<td>Texas A &amp; M University</td>
<td>December 1983; page 4-121</td>
</tr>
<tr>
<td>Underground Coal Gasification, India</td>
<td>Oil and Natural Gas Commission</td>
<td>March 1991; page 4-104</td>
</tr>
<tr>
<td>Underground Coal Gasification, Thunderbird II Project</td>
<td>In Situ Technology Wold-Jenkins</td>
<td>March 1985; page 4-102</td>
</tr>
<tr>
<td>Underground Coal Gasification, Washington State</td>
<td>Sandia National Laboratories</td>
<td>March 1983; page 4-124</td>
</tr>
<tr>
<td>Underground Gasification of Texas Lignite, Lee County Project</td>
<td>Basic Resources, Inc.</td>
<td>March 1985; page 4-101</td>
</tr>
<tr>
<td>Union Carbide Coal Conversion Project</td>
<td>Union Carbide/Linde Division United States Department of Energy</td>
<td>June 1984; page 4-92</td>
</tr>
<tr>
<td>University of Minnesota Low-BTU Gasifier for Commercial Use</td>
<td>University of Minnesota United States Department of Energy</td>
<td>March 1983; page 4-119</td>
</tr>
<tr>
<td>Utah Methanol Project</td>
<td>Questar Synfuels Corporation</td>
<td>December 1985; page 4-90</td>
</tr>
<tr>
<td>Verdigris</td>
<td>Agrico Chemical Company</td>
<td>September 1984; page C-35</td>
</tr>
<tr>
<td>Virginia Iron Corex Project</td>
<td>Virginia Iron Industries Corp.</td>
<td>March 1992; page 4-78</td>
</tr>
<tr>
<td>Watkins Project</td>
<td>Cameron Engineers, Inc.</td>
<td>March 1978; page B-22</td>
</tr>
</tbody>
</table>
STATUS OF COAL PROJECTS

COMPLETED AND SUSPENDED PROJECTS (Continued)

<table>
<thead>
<tr>
<th>Project</th>
<th>Sponsors</th>
<th>Last Appearance in SPR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Whitethorne Coal Gasification</td>
<td>United Synfuels Inc.</td>
<td>September 1984; page C-36</td>
</tr>
<tr>
<td>Wyoming Coal Conversion Project</td>
<td>WyCoalGas, Inc. (a Panhandle Eastern Company)</td>
<td>December 1982; page 4-112</td>
</tr>
<tr>
<td>Zinc Halide Hydrocracking Process Development</td>
<td>Conoco Coal Development Company Shell Development Company</td>
<td>June 1981; page 4-86</td>
</tr>
<tr>
<td>Company or Organization</td>
<td>Project Name</td>
<td>Page</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>------------------------------------------------------------------------------</td>
<td>------</td>
</tr>
<tr>
<td>ACME Power Company</td>
<td>ACME Coal Gasification Desulfurizing Process</td>
<td>4-46</td>
</tr>
<tr>
<td>AECL Ltd.</td>
<td>AECL Ammonia/Methanol Operations</td>
<td>4-47</td>
</tr>
<tr>
<td></td>
<td>Coalplex Project</td>
<td>4-53</td>
</tr>
<tr>
<td>Air Products and Chemicals, Inc.</td>
<td>Laporte Alternative Fuels Development Program</td>
<td>4-63</td>
</tr>
<tr>
<td></td>
<td>Texaco Cool Water Project</td>
<td>4-75</td>
</tr>
<tr>
<td>Alastair Gillespie &amp; Associates Ltd.</td>
<td>Scotia Synfuels Project</td>
<td>4-72</td>
</tr>
<tr>
<td>AMAX</td>
<td>AMAX/EMRC Mild Gasification Demonstration</td>
<td>4-48</td>
</tr>
<tr>
<td></td>
<td>Mild Gasification of Western Coal Demonstration</td>
<td>4-65</td>
</tr>
<tr>
<td>Amoco</td>
<td>British Solvent Liquid Extraction Project</td>
<td>4-49</td>
</tr>
<tr>
<td>Beijing Research Institute of Coal Chemistry</td>
<td>China Ash Agglomerating Gasifier Project</td>
<td>4-52</td>
</tr>
<tr>
<td>BEWAG AG</td>
<td>BEWAG GCC Project</td>
<td>4-48</td>
</tr>
<tr>
<td>Bharat Heavy Electricals Ltd.</td>
<td>BHEL Coal Gasification Project</td>
<td>4-48</td>
</tr>
<tr>
<td></td>
<td>BHEL Combined Cycle Demonstration</td>
<td>4-49</td>
</tr>
<tr>
<td>BP United Kingdom, Ltd.</td>
<td>Monash Hydroliquefaction Project</td>
<td>4-65</td>
</tr>
<tr>
<td>British Coal Corporation</td>
<td>Advanced Power Generation System</td>
<td>4-47</td>
</tr>
<tr>
<td></td>
<td>British Coal Liquid Solvent Extraction Project</td>
<td>4-49</td>
</tr>
<tr>
<td></td>
<td>CRE Spouted Bed Gasifier</td>
<td>4-54</td>
</tr>
<tr>
<td>British Department of Energy</td>
<td>British Coal Liquid Solvent Extraction Project</td>
<td>4-49</td>
</tr>
<tr>
<td>British Gas Corporation</td>
<td>MRS Coal Hydrogenator Process Project</td>
<td>4-66</td>
</tr>
<tr>
<td></td>
<td>Slagging Gasifier Project</td>
<td>4-73</td>
</tr>
<tr>
<td>Broken Hill Pty. Co. Ltd.</td>
<td>Broken Hill Project</td>
<td>4-50</td>
</tr>
<tr>
<td>Brookhaven National Laboratory</td>
<td>Brookhaven Mild Gasification of Coal</td>
<td>4-50</td>
</tr>
<tr>
<td>Brown Coal Liquefaction Pty. Ltd.</td>
<td>Victorian Brown Coal Liquefaction Project</td>
<td>4-77</td>
</tr>
<tr>
<td>Calderon Energy Company</td>
<td>Calderon Energy Gasification Project</td>
<td>4-50</td>
</tr>
<tr>
<td>Canadian Energy Developments</td>
<td>Frontier Energy Coprocessing Project</td>
<td>4-57</td>
</tr>
<tr>
<td>Canadian Federal Government</td>
<td>Western Canada IGCC Demonstration Plant</td>
<td>4-77</td>
</tr>
<tr>
<td>Carbofel</td>
<td>Colombia Gasification Project</td>
<td>4-53</td>
</tr>
<tr>
<td>Carbon Fuels Corp.</td>
<td>Char Fuels Project</td>
<td>4-51</td>
</tr>
<tr>
<td>Central Research Institute of Electric Power</td>
<td>CRIEPI Entrained Flow Gasifier</td>
<td>4-54</td>
</tr>
<tr>
<td>Industry</td>
<td>Char Fuels Project</td>
<td>4-51</td>
</tr>
<tr>
<td>China National Technical Import Corporation</td>
<td>Lu Nan Ammonia-from-Coal Project</td>
<td>4-64</td>
</tr>
<tr>
<td>Coal Association of Canada</td>
<td>Western Canada IGCC Demonstration Plant</td>
<td>4-77</td>
</tr>
<tr>
<td>Coal Conversion Institute, Poland</td>
<td>Polish Direct Liquefaction Process</td>
<td>4-68</td>
</tr>
<tr>
<td>Coal Corporation of Victoria</td>
<td>Monash Hydroliquefaction Project</td>
<td>4-65</td>
</tr>
<tr>
<td>Coal Gasification, Inc.</td>
<td>COGA-1 Project</td>
<td>4-53</td>
</tr>
</tbody>
</table>
## STATUS OF COAL PROJECTS

### INDEX OF COMPANY INTERESTS (Continued)

<table>
<thead>
<tr>
<th>Company or Organization</th>
<th>Project Name</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Technology Corporation</td>
<td>Mild Gasification Process Demonstration Unit</td>
<td>4-65</td>
</tr>
<tr>
<td>Combustion Engineering</td>
<td>Lakeside Repowering Gasification Project</td>
<td>4-63</td>
</tr>
<tr>
<td>Common Energy</td>
<td>IMHEX Molten Carbonate Fuel Cell Demonstration</td>
<td>4-61</td>
</tr>
<tr>
<td>Commonwealth Energy</td>
<td>Freetown IGCC Project</td>
<td>4-57</td>
</tr>
<tr>
<td>Continental Energy Associates</td>
<td>Humboldt Energy Center</td>
<td>4-60</td>
</tr>
<tr>
<td>Cordero Mining Company</td>
<td>Cordero Coal Upgrading Demonstration Project</td>
<td>4-53</td>
</tr>
<tr>
<td>Dakota Gasification Company</td>
<td>Great Plains Synfuels Plant</td>
<td>4-58</td>
</tr>
<tr>
<td>Delmarva Power &amp; Light</td>
<td>Delaware Clean Energy Project</td>
<td>4-55</td>
</tr>
<tr>
<td>Demkolec B.V.</td>
<td>SEP IGCC Power Plant</td>
<td>4-72</td>
</tr>
<tr>
<td>Destec Energy, Inc.</td>
<td>Dow Syngas Project</td>
<td>4-55</td>
</tr>
<tr>
<td></td>
<td>Wabash River Coal Gasification Repowering Project</td>
<td>4-77</td>
</tr>
<tr>
<td>DEVCO</td>
<td>Scotia Coal Synfuels Project</td>
<td>4-72</td>
</tr>
<tr>
<td>EAB Energie-Anlagen Berlin GmbH</td>
<td>BEWAG GCC Project</td>
<td>4-48</td>
</tr>
<tr>
<td>Electric Power Research Institute</td>
<td>Advanced Coal Liquefaction Pilot Plant</td>
<td>4-46</td>
</tr>
<tr>
<td></td>
<td>Laporte Alternative Fuels Development Program</td>
<td>4-63</td>
</tr>
<tr>
<td>Elsam</td>
<td>Elsam Gasification Combined Cycle Project</td>
<td>4-56</td>
</tr>
<tr>
<td>Encoal Corporation</td>
<td>Encoal LFC Demonstration Plant</td>
<td>4-56</td>
</tr>
<tr>
<td>ENDESA</td>
<td>Puertollano IGCC Demonstration Plant</td>
<td>4-69</td>
</tr>
<tr>
<td>European Economic Community</td>
<td>British Coal Liquid Solvent Extraction Project</td>
<td>4-49</td>
</tr>
<tr>
<td>Fundacao de Ciencia e Tecnologia (CIENTEC)</td>
<td>CIGAS Gasification Process Project</td>
<td>4-52</td>
</tr>
<tr>
<td></td>
<td>CIVOGAS Atmospheric Gasification Pilot Plant</td>
<td>4-52</td>
</tr>
<tr>
<td>GE Environmental Services, Inc.</td>
<td>GE Hot Gas Desulfurization</td>
<td>4-57</td>
</tr>
<tr>
<td>GEC/Alsthom</td>
<td>Advanced Power Generation System</td>
<td>4-47</td>
</tr>
<tr>
<td>General Electric Company</td>
<td>Freetown IGCC Project</td>
<td>4-57</td>
</tr>
<tr>
<td>German Federal Ministry of Research &amp; Technology</td>
<td>Bottrop Direct Coal Liquefaction Pilot Project</td>
<td>4-49</td>
</tr>
<tr>
<td></td>
<td>GFK Direct Liquefaction Project</td>
<td>4-58</td>
</tr>
<tr>
<td></td>
<td>Rheinbraun High Temperature Winkler Project</td>
<td>4-70</td>
</tr>
<tr>
<td>GFK Gesellschaft fur Kohleverflussigung</td>
<td>GFK Direct Liquefaction Project</td>
<td>4-58</td>
</tr>
<tr>
<td>Gulf Canada Products Company</td>
<td>Scotia Coal Synfuels Project</td>
<td>4-72</td>
</tr>
<tr>
<td>HOECHST AG</td>
<td>Synthesegasalanlage Rurh</td>
<td>4-73</td>
</tr>
<tr>
<td>Institute of Gas Technology</td>
<td>IGT Mild Gasification Project</td>
<td>4-61</td>
</tr>
<tr>
<td></td>
<td>IMHEX Molten Carbonate Fuel Cell Demonstration</td>
<td>4-61</td>
</tr>
<tr>
<td>Interprojekt Service AB</td>
<td>P-CIG Process</td>
<td>4-67</td>
</tr>
<tr>
<td>ISCOR</td>
<td>ISCOR Melter-Gasifier Process</td>
<td>4-62</td>
</tr>
</tbody>
</table>
## STATUS OF COAL PROJECTS

### INDEX OF COMPANY INTERESTS (Continued)

<table>
<thead>
<tr>
<th>Company or Organization</th>
<th>Project Name</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>K-Fuel Partners</td>
<td>K-Fuel Commercial Facility</td>
<td>4-62</td>
</tr>
<tr>
<td>The M.W. Kellogg Company</td>
<td>PETC Generic Coal Liquefaction Plants</td>
<td>4-67</td>
</tr>
<tr>
<td></td>
<td>Pressurized Fluid Bed Combustion Advanced Concepts</td>
<td>4-69</td>
</tr>
<tr>
<td>Kilborn International</td>
<td>Frontier Energy Coprocessing Project</td>
<td>4-57</td>
</tr>
<tr>
<td>Krupp Koppers GmbH</td>
<td>PRENFO Gasification Pilot Plant</td>
<td>4-68</td>
</tr>
<tr>
<td>Louisiana Gasification Technology, Inc.</td>
<td>Destec Syngas Project</td>
<td>4-55</td>
</tr>
<tr>
<td>Lurgi GmbH</td>
<td>BEWAG GCC Project</td>
<td>4-48</td>
</tr>
<tr>
<td></td>
<td>Rheinbraun High-Temperature Winkler Project</td>
<td>4-70</td>
</tr>
<tr>
<td>M-C Power Corporation</td>
<td>IMHEX Molten Carbonate Fuel Cell Demonstration</td>
<td>4-61</td>
</tr>
<tr>
<td>Minister of Economics, Small Business and Technology of the State of North-Rhine, Westphalia</td>
<td>Bottrop Direct Coal Liquefaction Pilot Plant</td>
<td>4-49</td>
</tr>
<tr>
<td></td>
<td>Synthesegasanlage Ruhr (SAR)</td>
<td>4-73</td>
</tr>
<tr>
<td>Mission Energy</td>
<td>Delaware Clean Energy Project</td>
<td>4-55</td>
</tr>
<tr>
<td>Monash University</td>
<td>Monash Hydroliquefaction Project</td>
<td>4-65</td>
</tr>
<tr>
<td>Morgantown Energy Technology Center</td>
<td>GE Hot Gas Desulfurization</td>
<td>4-57</td>
</tr>
<tr>
<td>New Energy and Industrial Technology Development Organization</td>
<td>CRIEPI IGCC Demonstration Project</td>
<td>4-54</td>
</tr>
<tr>
<td></td>
<td>Nedol Bituminous Coal Liquefaction Project</td>
<td>4-67</td>
</tr>
<tr>
<td>Nippon Steel Corporation</td>
<td>P-CIG Process</td>
<td>4-67</td>
</tr>
<tr>
<td>Nokota Company</td>
<td>Dunn Nokota Methanol Project</td>
<td>4-55</td>
</tr>
<tr>
<td>NOVA</td>
<td>Scotia Coal Synfuels Project</td>
<td>4-72</td>
</tr>
<tr>
<td>Nova Scotia Resources Limited</td>
<td>Scotia Coal Synfuels Project</td>
<td>4-72</td>
</tr>
<tr>
<td>Osaka Gas Company</td>
<td>MRS Coal Hydrogenator Process Project</td>
<td>4-66</td>
</tr>
<tr>
<td>Otto-Simon Carves</td>
<td>CRE Spouted Bed Gasifier</td>
<td>4-54</td>
</tr>
<tr>
<td>People's Republic of China</td>
<td>Mongolian Energy Center</td>
<td>4-66</td>
</tr>
<tr>
<td></td>
<td>Shanghai Chemicals from Coal Plant</td>
<td>4-73</td>
</tr>
<tr>
<td></td>
<td>Shougang Coal Gasification Project</td>
<td>4-73</td>
</tr>
<tr>
<td></td>
<td>Yunnan Province Coal Gasification Plant</td>
<td>4-79</td>
</tr>
<tr>
<td>Petro-Canada</td>
<td>Scotia Coal Synfuels Project</td>
<td>4-72</td>
</tr>
<tr>
<td>PowerGen</td>
<td>Advanced Power Generation System</td>
<td>4-47</td>
</tr>
<tr>
<td>PSI Energy Inc.</td>
<td>Wabash River Coal Gasification Repowering Project</td>
<td>4-77</td>
</tr>
<tr>
<td>Research Ass'n For Hydrogen From Coal Process Development, Japan</td>
<td>Hyco1 Hydrogen From Coal Pilot Plant</td>
<td>4-60</td>
</tr>
<tr>
<td>Rheinische Braunkohlwerke AG</td>
<td>Rheinbraun High-Temperature Winkler Project</td>
<td>4-70</td>
</tr>
<tr>
<td>Rosebud SynCoal Partnership</td>
<td>Western Energy Advanced Coal Conversion Process Demonstration</td>
<td>4-78</td>
</tr>
<tr>
<td>Ruhrkohle AG</td>
<td>Bottrop Direct Coal Liquefaction Pilot Plant Project</td>
<td>4-49</td>
</tr>
<tr>
<td></td>
<td>British Coal Liquid Solvent Extraction Project</td>
<td>4-49</td>
</tr>
<tr>
<td></td>
<td>Synthesegasanlage Ruhr (SAR)</td>
<td>4-73</td>
</tr>
</tbody>
</table>
### STATUS OF COAL PROJECTS

#### INDEX OF COMPANY INTERESTS (Continued)

<table>
<thead>
<tr>
<th>Company or Organization</th>
<th>Project Name</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ruhrkohle Oel und Gas GmbH</td>
<td>BEWAG GCC Project</td>
<td>4-48</td>
</tr>
<tr>
<td>RWE Energie AG</td>
<td>KoBra High-Temperature Winkler IGCC Demonstration Plant</td>
<td>4-63</td>
</tr>
<tr>
<td>Saabergwerke AG</td>
<td>GFK Direct Liquefaction Project</td>
<td>4-58</td>
</tr>
<tr>
<td>Sasol Limited</td>
<td>Sasol</td>
<td>4-71</td>
</tr>
<tr>
<td>SEP</td>
<td>SEP IGCC Power Plant</td>
<td>4-72</td>
</tr>
<tr>
<td>Shanghai Coking &amp; Chemical Corporation</td>
<td>Wujing Trigeneration Project</td>
<td>4-78</td>
</tr>
<tr>
<td>Sierra Pacific Power Company</td>
<td>Pinon Pine IGCC Power Plant</td>
<td>4-68</td>
</tr>
<tr>
<td>South Australia, Government of</td>
<td>South Australian Coal Gasification Project</td>
<td>4-73</td>
</tr>
<tr>
<td>Southern Company Services, Inc.</td>
<td>Hot Gas Cleanup Process</td>
<td>4-59</td>
</tr>
<tr>
<td>Stadtwerke Duisburg</td>
<td>German IGCC Power Plant</td>
<td>4-58</td>
</tr>
<tr>
<td>Star Enterprise</td>
<td>Delaware Clean Energy Project</td>
<td>4-55</td>
</tr>
<tr>
<td>TAMCO Power Partners</td>
<td>Tom's Creek IGCC Demonstration Project</td>
<td>4-76</td>
</tr>
<tr>
<td>Tampella Power</td>
<td>Tampella IGCC Process Demonstration</td>
<td>4-74</td>
</tr>
<tr>
<td>TECO Power Services</td>
<td>TECO IGCC Plant</td>
<td>4-74</td>
</tr>
<tr>
<td>Tennessee Eastman Company</td>
<td>Chemicals From Coal</td>
<td>4-51</td>
</tr>
<tr>
<td>Texaco Inc.</td>
<td>Delaware Clean Energy Project</td>
<td>4-55</td>
</tr>
<tr>
<td></td>
<td>Texaco Montebello Research Laboratory Studies</td>
<td>4-75</td>
</tr>
<tr>
<td>Texaco Syngas Inc.</td>
<td>Delaware Clean Energy Project</td>
<td>4-55</td>
</tr>
<tr>
<td></td>
<td>Freetown IGCC Project</td>
<td>4-57</td>
</tr>
<tr>
<td></td>
<td>Texaco Cool Water Project</td>
<td>4-75</td>
</tr>
<tr>
<td>ThermoChem, Inc.</td>
<td>ThermoChem Pulse Combustion Demonstration</td>
<td>4-75</td>
</tr>
<tr>
<td>TAMCO Power Partners</td>
<td>Tom's Creek IGCC Demonstration Project</td>
<td>4-76</td>
</tr>
<tr>
<td>Ube Industries, Ltd.</td>
<td>Ube Ammonia-From-Coal Plant</td>
<td>4-76</td>
</tr>
<tr>
<td>Uhde GmbH</td>
<td>Rheinbraun High-Temperature Winkler Project</td>
<td>4-70</td>
</tr>
<tr>
<td>United Kingdom Department of Energy</td>
<td>Advanced Power Generation System</td>
<td>4-47</td>
</tr>
<tr>
<td>United States Department of Energy</td>
<td>Advanced Coal Liquefaction Pilot Plant</td>
<td>4-46</td>
</tr>
<tr>
<td></td>
<td>Brookhaven Mild Gasification of Coal</td>
<td>4-50</td>
</tr>
<tr>
<td></td>
<td>Calderon Energy Gasification Project</td>
<td>4-50</td>
</tr>
<tr>
<td></td>
<td>Encoal LFC Demonstration Plant</td>
<td>4-56</td>
</tr>
<tr>
<td></td>
<td>Frontier Energy Coprocessing Project</td>
<td>4-57</td>
</tr>
<tr>
<td></td>
<td>Hot Gas Clean Up Process</td>
<td>4-59</td>
</tr>
<tr>
<td></td>
<td>Lakeside Repowering Gasification Project</td>
<td>4-63</td>
</tr>
<tr>
<td></td>
<td>Laporte Alternative Fuels Development Program</td>
<td>4-63</td>
</tr>
<tr>
<td></td>
<td>Mild Gasification Process Demonstration Unit</td>
<td>4-64</td>
</tr>
<tr>
<td></td>
<td>PETC Generic Coal Liquefaction Plants</td>
<td>4-67</td>
</tr>
<tr>
<td></td>
<td>Pinon Pine IGCC Power Plant</td>
<td>4-68</td>
</tr>
<tr>
<td></td>
<td>TECO IGCC Plant</td>
<td>4-74</td>
</tr>
<tr>
<td></td>
<td>ThermoChem Pulse Combustion Demonstration</td>
<td>4-75</td>
</tr>
<tr>
<td></td>
<td>Tom's Creek IGCC Demonstration Plant</td>
<td>4-76</td>
</tr>
</tbody>
</table>
### Status of Coal Projects

#### Index of Company Interests (Continued)

<table>
<thead>
<tr>
<th>Company or Organization</th>
<th>Project Name</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>University of North Dakota Energy and Environmental Research Center</td>
<td>Western Energy Advanced Coal Conversion Process Demonstration 4-78</td>
<td></td>
</tr>
<tr>
<td>Vebe Oel GmbH</td>
<td>AMAX/EMRC Mild Gasification Demonstration 4-48</td>
<td></td>
</tr>
<tr>
<td>Vereinigte Elektrizitswerke Westfalen AG</td>
<td>Bottrop Direct Coal Liquefaction Pilot Plant Project 4-49</td>
<td></td>
</tr>
<tr>
<td>Victoria, State Government of</td>
<td>VEW Gasification Process 4-76</td>
<td></td>
</tr>
<tr>
<td>Voest-Alpine Industrieanlagenbau</td>
<td>Victorian Brown Coal Liquefaction Project 4-77</td>
<td></td>
</tr>
<tr>
<td>Western Energy Company</td>
<td>ISCOR Melter Gasifier Process 4-62</td>
<td></td>
</tr>
<tr>
<td>Western Research Institute</td>
<td>Western Energy Advanced Coal Conversion Process Demonstration 4-78</td>
<td></td>
</tr>
<tr>
<td>Weyerhauser</td>
<td>Mild Gasification of Western Coal Demonstration 4-64</td>
<td></td>
</tr>
<tr>
<td>Wyoming Coal Refining Systems, Inc.</td>
<td>ThermoChem Pulse Combustion Demonstration 4-75</td>
<td></td>
</tr>
<tr>
<td>Yunnan Province, China</td>
<td>CharFuel Project 4-51</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Yunnan Lurgi Chemical Fertilizer Plant 4-79</td>
<td></td>
</tr>
</tbody>
</table>
MOSSGAS EXPECTS TO PRODUCE FIRST SYNTHESIS GAS IN JUNE

Mossgas, Ltd. now says it expects to produce its first synthesis gas in June 1992, about 9 months later than originally intended. This schedule change has also affected the project cost. At first the project was expected to be completed at a cost of $3.1 billion, but that estimate has now escalated to $4.2 billion.

An updated status of the Mossgas project was presented by T. Van Der Pas at the Alternate Energy '92 conference held in Charleston, South Carolina at the end of April.

The Sasol Synthol technology was selected for the Mossgas project, which is funded by the Government of South Africa. Economic justification for the project was based on an expected crude oil price of $32 per barrel during the early 1990s.

Government funding was provided with the condition that 85 percent local content be involved in the project and that maximum use be made of South African engineering companies and manufacturing workshops. Gencor, the second largest mining company in South Africa, agreed to manage the project and subsequently operate the complex in exchange for a 30 percent option in Mossgas.

Achieving 85 percent local content led to a number of joint ventures between South African and foreign engineering companies, which in turn resulted in a complex project organization. Maximizing local manufacturing led to quality and schedule problems. According to Van Der Pas, the consequences of maximizing South African content were underestimated, both in terms of time and money.

The complex is currently being commissioned. Gas reached the shore in March 1992 and all utilities are in operation. The first marketable product is expected during the early part of the fourth quarter of 1992. Full production is expected within 1 year thereafter.

Gas reserves, located in 350 feet of water, 55 miles off the southeast coast of South Africa, are sufficient to operate the synthesis facility for 30 years at design rate.

The onshore facility is situated on a 410 hectare site close to the shore and the town of Mossel Bay.

The process configuration of the facility is shown in a simplified blockflow diagram in Figure 1. Following is a brief description of the main processes involved.

Synthesis Gas Production

Gas and condensate arrive onshore in separate pipelines. In the Natural Gas Liquid Recovery plant any hydrocarbons heavier than propane are removed from the gas stream yielding lean natural gas.

The lean gas is fed to a two-stage methane reforming plant. The first stage consists of a tubular reforming plant which is followed by a secondary partial oxidation plant. The capacity of the three-train reforming plant would be sufficient for the production of some 7,000 tons per day of methanol.

Hydrogen, for the production of synthesis catalyst and for various hydrogenation steps in the refinery, is extracted from the reformer product gas by means of a pressure swing adsorption plant.

Synthesis Gas Conversion

Catalyst for the Synthol process is produced in the Catalyst Preparation and Reduction plants. The resulting product is then reduced with hydrogen to yield the iron-based catalyst.

The synthesis gas from the natural gas reforming plant is catalytically converted to predominantly light olefinic hydrocarbons in the Sasol Synthol process. The tailgas from Synthol is sent to the Tailgas Treatment plant where products (propylene, butylene and C5+ condensate) are cryogenically removed before the gas is recycled back to a natural gas reforming plant.

Synthol Product Refining

Synthetic crude from the Synthol process is fractionated in an atmospheric and vacuum distillation unit. The resulting products are highly olefinic and are kept separate from the natural gas condensate.

The light hydrocarbons, consisting predominantly of propylene and butylene are oligomerized over a synthetic zeolite catalyst. Whereas a conventional polymerization unit produces predominantly gasoline, the conversion process employed in the Mossgas refinery produces a large percentage of high quality diesel fuel.

Butane from natural gas liquid recovery and butylene from the tailgas treating unit are converted to high octane gasoline.

Naphtha from the Synthol oil fractionator is hydrotreated and isomerized to yield a high octane gasoline blendstock.
During 1995, lead free gasoline will be introduced in South Africa and the Mossgas complex will be able to produce approximately 50 percent of its gasoline lead free, according to Van Der Pas.

**Project Economics**

Based on the increased plant cost and the latest expected operating cost, the project now requires an equivalent crude oil price of around $35 per barrel to provide a 15 percent nominal return on funds invested.

For a neutral cash flow at full plant load, a crude oil price of $15 per barrel is required. Van Der Pas says the Mossgas project is not viable in the conventional sense of the word. Major reasons are the cost of the gas, the size of the operation and the inherent high capital cost of a synfuels plant. The cost of gas is in excess of $3.00 per million BTU.

Capital employed in the onshore facility amounts to $100,000 per barrel, compared with the cost of a normal refinery of some $30,000 per barrel.

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SYNTHETIC FUELS REPORT, JUNE 1992
DOE RELEASES DRAFT OF NATURAL GAS STRATEGY

Secretary of Energy J.D. Watkins asked the natural gas industry to review and comment on a "working draft" of the United States Department of Energy's (DOE) proposed strategy for future, federally-supported, gas-related programs.

Speaking to the National Petroleum Council in Washington, D.C. in April, Watkins said the strategy describes a new "borehole to burnertip" approach for federal natural gas research and development (R&D) and regulatory reform.

"We are presenting to the industry a new, systems-oriented approach for federal natural gas programs. It is an approach that has grown out of the efforts called for in the National Energy Strategy," Watkins said. "The strategy emphasizes programs to improve the utilization, delivery and storage of natural gas, and it refocuses ongoing supply-related R&D to better reflect near- and mid-term needs."

Delivery and storage R&D are new components of DOE's gas program, reflected for the first time in the agency's fiscal year 1993 budget request.

The strategy's resource and extraction programs include technologies for conventional gas formations as well as unconventional formations such as tight sands and gas-bearing shales.

Previous federal efforts concentrated almost solely on unconventional gas deposits.

The gas utilization area describes activities ranging from fundamental chemical research carried out by DOE's Office of Energy Research, to natural gas heating and cooling R&D and vehicle research conducted by the Office of Conservation, to high efficiency gas turbine technology and gas-to-liquids conversion projects overseen by the Office of Fossil Energy.

The proposed strategy also calls for continued efforts to reform federal and state statutes and regulations that restrict market opportunities for natural gas. It outlines new efforts to provide industry with the technologies to comply with environmental requirements without a decrease in economic natural gas production.

According to Watkins, the strategy is intended to mesh closely with efforts funded by the Gas Research Institute. A key element of the gas plan is the attention it gives to technology transfer to consumers and industry. Where appropriate, the strategy calls for future projects to be carried out by consortia of companies, industry organizations, universities, and state and federal agencies, with technology transfer an inherent part of each effort.
NERA LOWERS GAS PRICE FORECAST

National Economic Research Associates, Inc. (NERA) recently released its United States natural gas outlook. Due to January's price collapse and a bleak near-term economic outlook, NERA forecasts wellhead prices to average $1.50 per thousand cubic feet for natural gas in 1992. This is a significant drop in NERA's earlier forecast of $1.70. Comparatively, the 1993-1995 price projection is also lower. NERA's long-term gas price forecast, however, remains essentially unchanged at $2.50 per thousand cubic feet by the year 2000. Figure 1 illustrates the range of forecasts from different organizations. NERA interprets the past year of volatile natural gas prices as being the result of a deregulated natural gas market making the industry susceptible to the same boom-bust swings in the business cycle historically associated with metals and other natural resources. Being at the end of the current recession, NERA postulates, the natural gas market could once again take a sharp upswing.

Nonetheless, with natural gas prices at a 12-year low, many companies have halted exploration activities. Natural gas well completions totaled 8,700 in 1991, down from 9,900 in 1990. NERA forecasts that the 48-state gas reserve will fall in 1992 due to the reduction in drilling and well completions.

NERA's natural gas demand forecast sees consumption in the United States rising from last year's estimated 19.07 trillion cubic feet to about 19.7 trillion cubic feet this year, with electric utilities and industrial users accounting for most of the increased demand. Based on the projections, the deliverability surplus will average about 700 billion cubic feet in 1992, enough to keep gas prices from rising much from current depressed levels.

By 1993, however, a combination of increased demand (projected United States consumption of 20.3 trillion cubic feet) and another year of depressed drilling activity seems likely to lead to a considerably tighter gas market and the beginning of sustained upward pressure on gas prices. Prices could begin to escalate rapidly to a wellhead price (1991 dollars) of $1.81 per thousand cubic feet in 1994 and $1.96 in 1995.

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SYNTHETIC FUELS REPORT, JUNE 1992
COMBINED REFORMING AND PARTIAL OXIDATION GIVES IMPROVED ROUTE TO METHANOL

In a recent article in Hydrocarbon Processing, G.L. Farina of Foster Wheeler International Corporation in Milan, Italy and E. Supp of Lurgi AG in Frankfurt, Germany compare combined reforming technology with conventional processing to produce syngas from methanol. Energy consumption is reduced using the combined reforming process. Up to a 10 percent reduction in natural gas consumption per ton of methanol is achieved. In addition, less steam is consumed, and a syngas with the required stoichiometric composition for methanol synthesis is produced.

In order to achieve high flexibility of product gas composition and operating conditions, the authors selected a production method for synthesis gas that included steam reforming for hydrogen and autothermal reforming for carbon monoxide. The synthesis gases are produced in the desired stoichiometry required for the methanol synthesis.

Combined Reforming Versus Conventional Steam Reforming

A drastic reduction in energy consumption becomes possible when the two processes, conventional steam reforming plus autothermal reforming, are combined. The combination lowers the energy required per ton of methanol to 29 gigajoules. Figure 1 shows a block flow diagram illustrating combined reforming.

The two processes can be combined in such a way as to generate a synthesis gas with a stoichiometry of 2.05. The reformed gas can leave the steam reformer with a high methane slip. It is further reformed with oxygen in the autothermal reactor where the rest of the natural gas remains after bypassing the reformer.

The autothermic reactor is operated at a higher temperature in order to keep the residual content of methane in the syngas low.

In terms of economics, the energy required for the air and oxygen compression is offset by the energy saving in syngas and recycle gas compression. Energy savings by combined reforming results in 8 to 10 percent less natural gas required per ton of methanol.

Figure 2 (next page) compares the conventional and combined reforming plant costs. The two are comparable at around 1,300 to 1,500 tons per day of methanol. Above that capacity, it is most economical for plants to use combined reforming. This process also reduces CO₂ emissions by 35 percent and NOₓ emissions by 75 percent compared to conventional processing.

ACS MEETING HEARS PROGRESS ON DIRECT CONVERSION OF METHANE TO LIQUIDS

Recent progress in achieving direct conversion of methane to liquids was discussed by a number of researchers at the American Chemical Society's Division of Petroleum Chemistry symposium held in San Francisco, California in April. With natural gas still being flared in some locations because of high transportation costs, the focus of current work is on the direct catalytic conversion of methane to liquid fuels and chemicals. The eventual goal of these efforts is to make methane competitive with petroleum refining on a large scale. The rising demand for ethylene and higher olefins is another incentive to develop a direct methane conversion process.
Direct Oxidative Methane Conversion

D.E. Walsh, et al., of Mobil Research and Development Corporation, have been pursuing direct oxidative methane conversion at elevated pressures and moderate temperatures. Walsh pointed out that direct oxidative conversion of methane has typically involved its partial oxidation to methanol or its conversion to $C_2+$ hydrocarbons. Oxidative coupling to $C_2+$ is normally carried out below 5 atmospheres of pressure and above 700°C, while partial oxidation to methanol is usually performed at pressures above 50 atmospheres and at temperatures below 475°C.

Walsh reported on catalytic and noncatalytic oxidative methane conversion results observed at 900 psig and 550 to 600°C.

Walsh and his associates found that methanol formation is favored at elevated pressure and 450 to 475°C, and its selectivity declines with increasing conversion. At comparably low conversion and short residence time conditions, increasing temperature from 465 to 550°C alters the selectivity pattern from one which completely favors methanol to one in which a significant amount of ethane appears. Raising the partial oxygen pressure results in the dominance of $C_2+$ products. Thus, substantial reductions in the temperature for $C_2+$ formation may be realized, even in the absence of a catalyst, by increasing operating pressure.

Walsh concluded that the paths for the formation of methanol or $C_2+$ from methane are not linked. In addition, the importance of the catalyst appears to diminish with increased pressure. At high enough pressures, the methyl radical formation in noncatalytic systems can dominate any surface catalyzed contribution to radical formation.

Walsh thus suggests that the best catalysts may simply be those which are effective free radical generators and which minimally catalyze the over-oxidation of hydrocarbon products formed in the gas phase.

Mechanistic inferences based on these findings suggest that the challenge for improving $C_2+$ yields in direct methane conversion may be the discovery of catalytic materials which function by a dominantly heterogeneous mechanism at low temperatures and low to moderate pressures.

Gas Phase Partial Oxidation

G.A. Foulds, et al., of the CSIRO Division of Coal and Energy Technology, said that because the synthesis gas production step can account for up to 70 percent of the total cost for all gas conversion processes, this is the area that should be targeted for research. A logical alternative is the direct conversion of methane to methanol by partial oxidation.

To date, the most promising results have been obtained by the homogeneous gas phase reaction. However, different experimental approaches to the work have led to varying results, with methanol selectivities ranging from less than 10 percent to over 80 percent. In addition, there have been conflicting reports on the effect of process conditions such as oxygen concentration in feed gas and pressure on methanol selectivity. Another area of concern is the inconsistent measurement of reaction temperature.

Thus, the CSIRO researchers decided to reinvestigate the gas phase partial oxidation of methane in a tubular flow reactor. The work systematically investigated reaction temperature, pressure, feed oxygen concentration, and total gas flow rate on conversion and methanol yield and selectivity.

Under the conditions employed in their study, the major products of reaction are methanol, CO, and $CO_2$. The reactions which yield these products are all highly exothermic and generate temperature excursions, making isothermal operation extremely difficult.

The experiments resulted in oxygen conversions of over 95 mole percent, with the relative quantities of the product spectrum varying depending on the process conditions employed. The reaction is most sensitive to reaction temperature, but there is considerable interaction between the process parameters.
A discontinuity was observed in both methane and oxygen conversion as a function of reaction temperature, with oxygen conversion jumping from less than 10 mole percent to above 90 mole percent over a small increase in temperature. At higher feed oxygen concentrations, this discontinuity has been shown to exhibit hysteresis and the system is bistable. This phenomenon together with kinetic modeling strongly supports the occurrence of a "cool-flame" mode which is oscillatory at these concentrations.

Methanol forms at the start of the discontinuity and both selectivity and yield pass through a maximum as the reaction temperature is increased. Further increase in temperature results in a decrease in methanol selectivity and yield.

Increasing the pressure results in the discontinuity, and hence high conversion, occurring at a lower temperature. Increasing the pressure from 1.5 MPa to 3.0 MPa results in enhanced methanol yield.

An increase in the oxygen concentration in the feed diminishes the methanol selectivity, but increases the methane conversion considerably. As a result, methanol yield, which is a function of both conversion and selectivity, increases as the feed oxygen concentration is increased. However, the magnitude of the increase diminishes at higher oxygen concentrations as the decrease in selectivity becomes more pronounced.

Noncatalytic Partial Oxidation

M.J. Foral, of Amoco Oil Company's Research and Development Department, has been investigating noncatalytic partial oxidation of natural gas. He says that the direct conversion of methane to methanol via partial oxidation could substantially reduce capital and energy requirements for methanol production. Foral studied the effects of hydrocarbon feed composition, oxygen concentration, temperature, pressure, and reactor diameter.

The experiments were carried out in a small pilot plant designed for studying the direct conversion of light hydrocarbon gases to products such as methanol, gasoline, ethylene, and synthesis gas. A schematic diagram of the plant is shown in Figure 1.

Foral concluded that higher \( (C_2^+ \) hydrocarbons in the feed significantly affect both methane conversion and total hydrocarbon conversion. Methane conversion decreases and total hydrocarbon conversion increases in the presence of \( C_2^+ \) hydrocarbons.

Lower oxygen concentrations improve methanol selectivity, but reduce per-pass methane conversion. Methanol yield is maximized at oxygen concentrations above 8 volume percent.

Lower temperatures and higher pressures are desirable for maximizing both methanol yield and methane conversion.

Average reactor temperatures of 700 to 900°F and a pressure of 1,300 psig appear to be optimal within the ranges studied.

Reactor diameter (surface-to-volume ratio) can be an important parameter in this system, he says. This is particularly true at low oxygen concentrations, where smaller diameter reactors give the best results. In addition, packing the large diameter reactor with quartz beads improves methanol selectivity at low oxygen concentrations (below 5 volume percent \( O_2 \)), but has little effect at higher oxygen levels.

Approaches to Higher Yield

J.G. McCarty of SRI International reported on his research on approaches to higher yield in methane conversion processes. Despite intensive research on the catalytic coupling process, said McCarty, the single-pass yields of hydrocarbons from a variety of approaches have generally not exceeded 25 percent.

McCarty said the selective oxidation of methane and ethane into desirable products such as methanol and ethylene, is limited by two types of side reactions: direct oxidation of reactive intermediates, and the parallel conversion of the desired metastable products into deep oxidation byproducts.

New approaches for higher yield processes, including low temperature catalytic selective oxidation, co-ox coupling using free radical promoters (Cl), redox coupling, co-ox coupling using free radical scavengers, etc., were evaluated in light of realistic selectivities.

According to McCarty, the selectivity of the gas phase kinetics could be influenced by the addition of highly selective free radicals promoters, or by the introduction of compounds that selectively remove the least selective radicals already present during oxidative methane conversion.
The addition of halogens in a high temperature partial oxidation process is, however, undesirable because it complicates an already difficult materials selection problem and because halogenated hydrocarbon byproducts would be created.

A strategy related to use of gas phase suppression additives would be to use the catalyst itself to adsorb and consume destructive radicals while preserving desirable radicals.

Another approach suggests that the undesirable consequences of gas phase kinetics could be avoided at lower temperatures. Ideally, the pool of gas phase radicals would decrease to a point where they were always less significant than the heterogeneous components.

McCarty also said that redox reactions offer a more clearly visualized way of avoiding deleterious oxidation reactions caused by gas phase kinetics because the oxygen is introduced in a separate stage of the overall process.

Use of complex oxides or composite catalysts that include a selective catalyst with poor oxygen retention to enhance the selectivity of a redox oxide appear to have some potential to pass the barriers imposed by gas phase kinetics. However, these redox materials still must pass the test required of all co-feed selective catalysts, the rapid activation of methane with minimal conversion of desired products.

Partial Oxidation Over ZSM 5 Catalyst

S. Han, et al., from Mobil Research and Development Corporation, discussed direct partial oxidation of methane to liquid hydrocarbons over ZSM 5 catalyst. The researchers reported the formation of aromatic-rich liquid hydrocarbons from the direct partial oxidation of methane with oxygen over ZSM 5 zeolite in the presence of small amounts of a higher hydrocarbon additive such as propane or propene in the feed. The additive was believed to initiate the methanol-to-gasoline reaction and may be effective at eliminating the slow initiation phase observed with pure methanol feeds.

A methane and oxygen feed processed over ZSM 5 produced exclusively carbon monoxide and methanol. However, with C₃ additive in the feed over ZSM 5, product selectivities shifted significantly towards the formation of liquid hydrocarbons, which are rich in aromatics. Methanol selectivities for these systems were extremely low indicating conversion to gasoline over the zeolite.

Because the C₃ component alone cannot account for the yield of higher hydrocarbons, methane participation is evident. Calculations at the limiting cases of additive utilization suggest the selectivity to useful products for the methane conversion is in the range of 7 to 19 percent.

This is the first instance in which significant quantities of C₂+ liquid hydrocarbons were produced directly from methane by direct partial oxidation with oxygen.

Activation of Reactants by Metal Oxide Catalysts

J.A. Lapszewicz, et al., of the CSIRO Division of Coal and Energy Technology, have focused their investigations on the activation of reactants by metal oxide catalysts. While some mechanistic aspects of oxidative coupling of methane are now well understood, they say, the factors which govern catalysts performance remain unclear. The researchers studied the relationship between the ability of a series of catalysts to activate both methane and oxygen, and their activity and selectivity for the oxidative coupling reaction.

The following conclusions were drawn from their study:

- The methane conversion rate in an oxidative coupling reaction does not correlate with the ability of the catalyst surface to dissociate either methane or oxygen or both.

- Formation of the methyl radicals cannot be explained by a simplistic mechanism involving either heterolytic dissociation of methane on the catalyst surface or its interaction with oxygen. It is more likely that a multi-step mechanism or specific characteristics of the active site is involved.

- Selectivity to C₂ hydrocarbons can be explained by the relative activation of methane and oxygen on the catalyst surface. As methane is weakly acidic and oxygen weakly basic, the ratio of the activation rates is high over basic catalysts.

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BOLIVIA SET TO BECOME GAS EXPORTER

Bolivia's state-owned oil and gas company, Yacimientos Petrolíferos Fiscales Bolivianos (YPFB), is negotiating contracts for natural gas with Argentina and Brazil. Present production of natural gas in Bolivia is 530 million standard cubic feet per day. Of that, 215 million standard cubic feet per day are exported to Argentina and the remaining natural gas is used domestically, stockpiled, or converted to liquid petroleum gas. YPFB foresees expanding the industry to 4.4 trillion standard cubic feet. At the "Latin America's Plans for the Natural Gas Sector" conference in La Jolla, California in March, G. Jimenez discussed the "Natural Gas Strategy in Bolivia."

Bolivia's economy currently uses little natural gas. YPFB anticipates the market to expand over the next 5 years. The government has introduced incentives to switch from liquid hydrocarbons to natural gas. The use of natural gas to make fertilizer and methanol will be encouraged.

Foreign export may be an increasing area of interest. Chile, Paraguay, Peru and Uruguay are interested in negotiating contracts. Presently, Argentina is renegotiating their contract which expired in April 1992. The new contract is expected to include 300 million standard cubic feet per day of natural gas in 1995, and then increasing to 600 million standard cubic feet per day in the year 2000. In addition, 100 million standard cubic feet will be made available for powerplants.

Paraguay is considering constructing a pipeline that would run through Paraguay to Brazil to carry up to 150 million standard cubic feet per day. Chile may sign an agreement for 150 million standard cubic feet per day to supply their North territory, while a joint venture between Argentina and Bolivia may be signed for exports to Japan. The natural gas would first be converted to liquid natural gas in Chile's port of Tocopilla.

To facilitate the expanding natural gas industry, Bolivia is preparing guidelines in a "Gas Code for Bolivia." In addition, loans from financial institutions such as the World Bank and Interamerican Development Bank have aided the industry's expansion.
CANADIAN EXCESS GAS DELIVERABILITY TO REMAIN FOR 2 YEARS

In late 1991, the Canadian Energy Research Institute (CERI) commenced a study to determine Canada's excess natural gas deliverability over the 1990 to 1995 period. To accomplish this, CERI staff surveyed 29 of the largest 30 natural gas producers in Canada and received information regarding each company's historical and future annual productive capacity and production, by province and territory. These 29 companies represent 76 percent of total Canadian 1990 natural gas production. The majority of the survey participants also provided the corporate average natural gas price forecast upon which their projections of deliverability and production are based. In March the "Survey of Canadian Excess Natural Gas Deliverability 1990-95" was released.

Regarding deliverability, the survey results indicate that, except for an insignificant amount, all participants' deliverability will continue to come from the three Western Canadian provinces of British Columbia, Alberta, and Saskatchewan. Alberta's share of the total is expected to remain above 80 percent throughout the study period.

According to the aggregated data, the participants' total annual deliverability is projected to remain stable near the 3.5 to 3.6 trillion cubic foot level as the declines in deliverability from currently connected gas are expected to be offset from gas that will be connected from proved reserves and from reserve additions.

Natural gas production by the survey participants, in total, is projected to rise steadily from 2.6 trillion cubic feet in 1990 to 3.1 trillion cubic feet in 1995 (3.9 percent annually).

Combining the 1990 to 1995 deliverability and production levels determines the group's average annual surplus productive capacity, as shown in Figure 1. For 1990, this surplus is estimated to have been 875 billion cubic feet, or 25 percent

FIGURE 1

SURVEY PARTICIPANTS' GAS PRODUCTION VERSUS DELIVERABILITY

<table>
<thead>
<tr>
<th>Year</th>
<th>Deliverability Tcf</th>
<th>Production Tcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>1990</td>
<td>3.488</td>
<td>2.614</td>
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<td>3.563</td>
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<td>1993</td>
<td>3.613</td>
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<td>1994</td>
<td>3.516</td>
<td>2.993</td>
</tr>
<tr>
<td>1995</td>
<td>3.521</td>
<td>3.095</td>
</tr>
</tbody>
</table>

SOURCE: CERI

SYNTHETIC FUELS REPORT, JUNE 1992
of the 29 companies' total deliverability. By 1993, the surplus capacity falls to 640 billion cubic feet (18 percent of deliverability) and to 425 billion cubic feet (12 percent of deliverability) by 1995.

Most of the survey participants (23 of the 29) also provided their average annual plant gate natural gas price projections through 1995. Prices are expected to remain fairly soft, with the 1995 average price of $1.69 per thousand cubic feet virtually the same as the 1990 price of $1.64 per thousand cubic feet.

It is evident from the aggregate survey data that excess gas deliverability will remain for at least the next several years, despite the participants' plans to add relatively little new deliverability capacity.

According to CERI, the clear implications of this study are that Canadian natural gas prices will likely remain soft for at least the next several years, to the benefit of gas consumers both in Canada and the United States.

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NATURAL GAS PUBLICATIONS/PATENTS

RECENT PUBLICATIONS

The following papers were presented at the American Chemical Society Symposium on "Natural Gas Upgrading II," held in San Francisco, California, April 5-10:

Noble, R.D., "Overview—Catalytic Membrane Reactors"

Frese, K.W., Jr., et al., "Partial Oxidation of Methane in Aqueous Electrochemical Systems"

Foulds, G.A., et al., "Gas Phase Partial Oxidation of Methane"

Foral, M.J., "The Noncatalytic Partial Oxidation of Natural Gas to Methanol"

Koranne, M.M., et al., "Primary and Secondary Reactions During the Partial Oxidation of Methane to Formaldehyde"

Weng, T., et al., "Catalytic Partial Oxidation of Methane to Formaldehyde"


Han, S., et al., "Partial Oxidation of Methane to Liquid Hydrocarbons Over ZSM-5 Catalyst"

Mauti, R., et al., "Dynamic Isotope Tracing of Methane: Selective Oxidation Over Silica Supported MoO₃"

Goodman, D.W., "The Activation of Small Alkanes: A Surface Science Perspective"

Sinev, M.Y., et al., "Structural Aspects of MgO/Nd₂O₃ Catalysts for the Oxidative Coupling of Methane"

Dubois, J.-L., et al., "Surface Carbonate on Methane Coupling Catalysts: A Poison or A Catalyst Itself?"

Kaminsky, M.P., et al., "Deactivation of Li-Based Catalysts for Methane Oxidative Coupling"

Dooley, K.M., et al., "Potassium/Calcium/Nickel Catalysts for Oxidative Coupling of Methane"

Erekson, E.J., et al., "Conversion of Methane to Ethylene"

Lapszewicz, J.A., et al., "Activation of Reactants by Metal Oxide Catalysts—A Key to Selectivity of Oxidative Methane Coupling?"

Borchert, H., et al., "The Effect of Oxygen Ion Conductivity of Catalysts for their Performance in the Oxidative Coupling of Methane"

Kalenik, Z., et al., "Isotopic Studies of the Effect of Promotion on the Activity of La₂O₃, ThO₂ and ZrO₂ Catalysts During Oxidative Dimerization of Methane"

Alcock, C.B., et al., "Coupling Reactions on Oxide Solid Solution Catalysts"

White, J.H., et al., "Heterogeneous Methane Oxidative Dimerization Using Perovskite Catalysts"

Mazanec, T.J., et al., "Electrocatalytic Cells for Chemical Reaction"

Walsh, D.E., et al., "Direct Oxidative Methane Conversion at Elevated Pressure and Moderate Temperatures"

McCarty, J.G., "Approaches to Higher Yield in Methane Conversion Processes"

Feng, Y., et al., "Fundamental Studies of Gas/Surface Processes Occurring During Methane Coupling on 1% Sr/La₂O₃"

SYNTHETIC FUELS REPORT, JUNE 1992
Zanthoff, H.W., et al., "Combined Kinetics of Catalytic and Non-Catalytic Reactions in the Oxidative Coupling of Methane"

Machin, I., et al., "Modeling of the Catalytic Oxidative Coupling of Methane"

Olsbye, U., et al., "A Kinetic Study of the Oxidative Coupling of Methane Over a BaCO_3/La_2O_3 (CO_3)_3-n Catalyst"

Hair, I.M., et al., "Modeling of the Catalytic Oxidative Coupling of Methane"

Pereira, P.R., et al., "Reactivity Studies of C_1 and C_2 Hydrocarbons with Oxygen Over an Alkali-Based Mn Oxide Catalyst"

Tjatjopoulos, G.J., et al., "Simulation of High-Velocity Fluidized Bed Reactors for the Oxidative Coupling of Methane"

Smith, K.J., et al., "An Overview of the Higher Alcohol Synthesis"

Roberts, G.W., et al., "The Thermodynamics of Higher Alcohol Synthesis"

Kazi, A.M., et al., "CO Hydrogenation Over Lanthana Promoted Cobalt Catalysts"

Karles, G.D., et al., "CO Hydrogenation Catalysis-Selective Formation of Isobutene"

Minet, R.G., et al., "Experimental Studies of a Ceramic Membrane Reactor for the Steam/Methane Reaction at Moderate Temperatures (400-700°C)"


Stoukides, M., et al., "Nonoxidative Methane Coupling and Synthesis Gas Production in Solid Electrolyte Cells"


Dufaux, M., et al., "Stable Zeolite Catalysts for the Selective Oxyhydrochlorination of Methane"

Noceti, R.P., et al., "Advances in Methane Oxyhydrochlorination Catalysts"

Sen, A., et al., "Organometallic Approaches to Methane Activation"

Labinger, J.A., "Overcoming the Problem of Selectivity in Methane Activation via Homogeneous Catalysis"

Bergman, R.G., "Activation of Carbon-Hydrogen Bonds in Alkanes and Other Organic Molecules using Organotransition Metal Complexes"

Lyons, J.E., et al., "Air-Oxidation of Light Alkanes by First-Row Transition Metals in Macroyclic Ligand Environments"


Belgued, M., et al., "Homologation of Methane on Metallic Surfaces—Consideration of Reaction Pathways"

Koerts, T., et al., "A Low Temperature Reaction Sequence for Methane Conversion"

Khouw, C.B., et al., "Alkane Activation with Aqueous H_2O_2 by Titanium, Copper and Iron Containing Zeolites"

Zerger, R.P., et al., "Preparation of Oxygenates with Methane/Oxygen Microwave Plasmas"

STATUS OF NATURAL GAS Projects
COMMERCIAL PROJECTS (Underline denotes changes since March 1992)

FUELCO SYNHYTECH PLANT — Fuel Resources Development Company (G-10)

Fuel Resources Development Company (FuelCo) held ground breaking ceremonies in May 1990 for their Synhytech Plant at the Pueblo, Colorado landfill. The Synhytech Plant, short for synthetic hydrocarbon technology, will convert the landfills' methane and carbon dioxide gas into clean burning diesel fuel as well as naphtha and a high grade industrial wax.

The technology is said to be the world's first to convert landfill gases into diesel motor fuel. It was developed by FuelCo, a wholly owned subsidiary of Public Service Company of Colorado, and Rentech Inc. of Denver, Colorado. Fuelco is planning to invest up to $16 million in the project with Rentech having the option to purchase 15 percent of the plant. Ultrasystems Engineers and Constructors is designing and building the project.

The plant is expected to produce 100 barrels of diesel, plus 50 barrels of naphtha and 80 barrels of high grade wax per day. It is estimated that the Pueblo site will sustain a 235 barrel per day production rate for about 20 years. FuelCo estimates that diesel fuel can be produced for about $18 per barrel.

The process takes the landfill gas—which is about 52 percent methane and 40 percent carbon dioxide—breaks it down and passes it through an iron-based slurry-phase catalyst, and extracts diesel fuel, naphtha and wax.

According to vehicle test results at high altitude, the Synhytech diesel was 35 percent lower in particulate emissions and produced 53 percent fewer hydrocarbons and 41 percent less carbon monoxide in the vehicle exhaust. It contains no sulfur and only low levels of aromatics, and no engine modifications are required. Plant construction was complete in December 1991 and the first crude product was produced in January 1992.

Project Cost: $16 million

MOSSGAS SYNFAELs PLANT — South African Central Energy Fund (70%), Engen Ltd. (30% optional) (G-20)

In 1988 the South African government approved a plan for a synthetic fuels from offshore natural gas plant to be located near the town of Mossel Bay off the southeast coast. Gas for the synthesis plant will be taken from an offshore platform which was completed in 1991. The SASOL Synthol technology has been selected for the project.

Construction of the onshore plant is scheduled for completion in mid-1992. The complex is expected to produce its first products by the third quarter of 1992 and to be in full production by the third quarter of 1993. The product slate will be liquefied petroleum gas, 93 and 97 octane gasoline, kerosene and diesel.

The break-even point for the project will be reached with crude oil prices of $35 per barrel. Engen is the project manager and will be the operator of the facility. The project was financed 80 percent by the Central Energy Fund and 20 percent by commercial loans.

Gas reserves, located in 350 feet of water, 55 miles off the Southeast coast of South Africa, are sufficient to operate the synthesis facility for 30 years at design rate.

Gas and condensate arrive onshore in separate pipelines. In the Natural Gas Liquid Recovery plant any hydrocarbons heavier than propane are removed from the gas stream yielding lean natural gas. The lean gas is fed to a two-stage methane reforming plant. The first stage consists of a tubular reforming plant which is followed by a secondary partial oxidation plant. The capacity of the three-train reforming plant would be sufficient for the production of 7,000 tons per day of methanol.

Using an iron-based catalyst, the synthesis gas from the natural gas reforming plant is catalytically converted to predominantly light olefinic hydrocarbons. The tailgas from Synthol is sent to the Tailgas Treatment plant where products (propylene, butylene and C₃+ condensate) are cryogenically removed before the gas is recycled back to a natural gas reforming plant.

Project Cost: $4.2 billion

NEW ZEALAND SYNFUELS PLANT — Fletcher Challenge, Ltd. (75%), Mobil Oil of New Zealand Ltd., (25%) (G-30)

The New Zealand Synthetic Fuels Corporation Limited (Synfuel) Motunui plant was the first in the world to convert natural gas to gasoline using Mobil's methanol-to-gasoline (MTG) process. Construction began in early 1982 and the first gallon of gasoline was produced in October 1985. In the first 8 months of commercial production the plant produced 448,000 tonnes of gasoline or about 35 percent of New Zealand's total demand for that period.
STATUT OF NATURAL GAS PROJECTS (Underline denotes changes since March 1992)

COMMERCIAL PROJECTS (Continued)

During the first two years of operation, the Synfuel plant suffered several shutdowns in the methanol units thus causing production shortfalls despite reaching the one million tons of gasoline mark in 1988. A successful maintenance turnaround and several improvements to the MTG waste water plant have improved efficiency considerably. In 1990 the plant produced about 12,000 barrels of gasoline per day. This is about 34 percent of New Zealand's gasoline needs.

The plant is located on the west coast of New Zealand's North Island in Taranaki. It is supplied by the offshore Maui and Kapuni gas fields. The synthetic gasoline produced at the plant is blended at the Marsden Point refinery in Whangarei. The plant is a tolling operation, processing natural gas owned by the government into gasoline for a fee. Synfuels, thus does not own the refined product.

Synfuel was owned 75 percent by the New Zealand government and 25 percent by Mobil Oil of New Zealand Ltd. However, the Petroleum Corporation of New Zealand (Petrocorp) entered an agreement with the New Zealand government to assume its 75 percent interest in the corporation. The New Zealand government had been carrying a debt of approximately $700 million on the plant up to that point. Petrocorp is owned by Fletcher Challenge, Ltd.

The synfuel plant produced a record 562,000 tonnes of gasoline in the first 6 months of 1991. A percentage of crude methanol was pipelined to Fletcher's Petralgas plant to produce 186,000 tonnes of chemical grade methanol.

Fletcher Challenge will exercise its option to require the government to buy NZ$400 million (US$222 million) of new shares from the company.

SHELL MALAYSIA MIDDLE DISTILLATES SYNTHESIS PLANT - Shell MDS (60%), Mitsubishi (20%), Petronas (10%), Sarawak State Government (G-50)

The Royal Dutch/Shell Group is building the world's first commercial plant to produce middle distillates from natural gas in Malaysia. The $660 million unit is being built next to the Bintulu LNG plant in the state of Sarawak. The plant will produce approximately 500,000 metric tons of products per year from 100 million cubic feet per day of natural gas feedstock.

The operator for the project will be Shell MDS. The main construction contract was let to JGC Corporation of Japan. Site preparations began in late 1989, with completion scheduled for late 1992.

The Shell middle distillates synthesis process (SMDS) is based on modernized Fischer-Tropsch technology which reacts an intermediate synthesis gas with a highly active and selective catalyst. The Shell catalyst minimizes coproduction of light hydrocarbons unlike classical Fischer-Tropsch catalysts. Middle distillates will be the main product, but the plant will have operating flexibility so that while maintaining maximum output, the composition of the product package, which will contain low molecular weight paraffin waxes, can be varied to match market demand. Shell will use its own gasification technology to produce the synthesis gas.

Four reactors for the heavy paraffin synthesis unit, said to be the largest in the world, have been delivered to the plant site. These vessels were built in Italy, but overall construction is being handled by JGC Corporation of Japan.

Project Cost: $660 million