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CSIRO Continues Strong Liquid Fuels Program

The annual report from CSIRO says that it is necessary to develop economic processes to produce synthetic fuels. CSIRO's Coal and Energy Technology Division has established a program to improve the processes and equipment used to produce liquid and gaseous fuels from sources other than crude oil. See page 1-1 for a brief summary and progress report on this program.

DOE Fossil Energy Budget Holds Its Ground

The United States Department of Energy's (DOE) budget for fossil energy research and development for fiscal year 1992 amounts to $449.6 million, only a slight decrease from the previous year's budget amount. As detailed on page 1-3, the budget for petroleum research and development was increased, while the agency's budget for oil shale research and development was significantly reduced. The overall budget for coal research and development was slightly reduced.

New SBIR Solicitation Covers Alternative Fuels

The United States Department of Energy's tenth annual solicitation for the Small Business Innovation Research program (SBIR) lists a large number of technical topics that involve processes for producing, improving and enhancing utilization of alternative fuels. A selected number of these topics are discussed in the article beginning on page 1-3. DOE anticipates making approximately 150 grant awards in amounts up to $50,000 for projects of about 6 months duration.

Politics More Important Than Economics in Projecting Oil Market

C.H. Tahmassebi of Ashland Oil, Inc. says oil market projections will require a good deal of political knowledge in addition to the usual economic background and trends. In addition to Ashland Oil's crude oil supply/demand outlook to the year 2000, the article on page 1-10 summarizes the role that political events will play in attempting to accurately project worldwide crude oil market conditions.

Study by Environmental Groups Suggests Energy Use Could be Cut in Half

A 2-year study conducted by scientists, engineers and economists from four environmental groups says that the United States could cut its projected energy consumption nearly in half, quadruple its renewable energy use, and save consumers $2.3 trillion by the year 2030. The analysts evaluated more than 100 energy technologies and mapped out four possible future energy scenarios. A summary of this work is presented on page 1-10.

OTA Reports on U.S. Oil Import Vulnerability

The congressional Office of Technology Assessment (OTA) has released its revised estimates on oil replacement capability in the United States. The study analyzed an oil disruption scenario involving the loss of 5 million barrels of oil per day of United States oil imports for at least a 5-year period, an amount roughly equivalent to the loss of Persian Gulf production. As discussed on page 1-14, OTA concludes that the United States could effectively replace from 1.7 to 2.8 million barrels per day, leaving a shortfall of 2.2 to 3.3 million barrels of oil per day.
Flexible Fuel Conversion Plants Proposed

A novel concept to develop flexible fuel conversion plants, which could use any and all domestically available alternative fuels, is discussed on page 1-21. Such fuel conversion plants would allow the transportation system in the United States to be based on domestic resources. Furthermore, transportation fuels made from domestic resources would become cost competitive at an imported crude oil price of about $30 per barrel.

Continuation of Australian Energy Exports Recommended

An energy policy statement from Australia's Minister for Resources says that Australia can best achieve its national objectives by being an efficient producer and exporter of energy. As outlined on page 1-23, the statement says that Australia's role as a producer and trader of energy resources will increase over the next decade and the country should maximize its role in meeting international needs for the traditional fossil fuels.

Northlake Industries Demonstrates Shale Extraction Process

In November, Northlake Industries conducted a demonstration of its HDR extractor using ore from the White River Oil Shale Mine in Utah. As discussed on page 2-1, Northlake officials plan to have a 1,000 barrel per day commercial unit in operation by July 1992. Officials say that the results from the demonstration indicate an extraction cost of under $8 per barrel with an oil recovery rate of 66 gallons per ton of oil shale.

MTCI Wins SBIR Grant for Oil Shale Retorting

A $49,993 grant for developing an advanced oil shale retorting technology has been awarded to Manufacturing and Technology Conversion International (MTCI) by the United States Department of Energy under Phase I of its 1991 Small Business Innovation Research program. A brief discussion of the project is presented on page 2-3. The proposed technology uses a compact, indirectly heated fluidized bed system.

Paraho Projects 30 percent Return on Shale Oil Asphalt

Recent figures from New Paraho Corporation show that the company expects a rate of return of around 30 percent on their shale oil modified asphalt, called SOMAT. An economic feasibility study, discussed on page 2-5, was based on a facility designed to produce 2,700 barrels of asphalt modifier (SOM) per day from 3,380 barrels of crude oil per day. The plant will also produce 680 barrels of light oil per day, to be marketed as a byproduct.

Use of Spent Shale in Cement Manufacture Offers Economic Benefits

Using spent shale in cement production can have economic benefits for both the oil producer and the cement manufacturer. The economic potential represented by the use of spent shale in cement making, estimated to be in the range of $6 to $10 per ton, can be realized where mineable shale exists in close proximity to a cement plant. A discussion of this potential market for spent shale is presented on page 2-6.

Fifty Pound Per Hour Cold Flow Tests Carried Out on Kentort Design

A cold flow model of the Kentort H process has been demonstrated at the 50-pound-per-hour scale using three different particle size distributions. The model was built to verify flow rates and solid
recycle rates in a larger reactor size. The results of the demonstration and a description of the cold flow model are given on page 2-11. Data from the demonstration will be used in the final design and construction of the Kentort II retort.

Creation of Low Permeability Layers Could Retard Leaching from Shale Piles

The presence of one or more low permeability layers within a pile of spent shale influences the rate of water movement in the pile and, thus, retards leaching. A study on hydraulic conductivity within piles of spent shale has shown that the bulk of disposed spent shale will allow subsequent hydration and result in the eventual degradation of groundwater. A discussion on how to create low permeability layers to prevent leaching is presented on page 2-14.

NaTec Resources Producing Nahcolite in Piceance Basin

NaTec Resources Inc. is producing nahcolite, a naturally occurring sodium bicarbonate, by in situ solution mining. NaTec is marketing the nahcolite as part of its proprietary system for injecting dry sodium bicarbonate into the stacks of coal burning power plants. The in situ solution mining operation, located in Colorado's Piceance Basin, is described in the article on page 2-17.

Proposal Made to Lease Naval Oil Shale Reserve for Gas Development

A bill has been introduced in a House of Representatives subcommittee which would allow the United States Bureau of Land Management to begin leasing operations on 55,000 acres set aside in the early part of this century as the Naval Oil Shale Reserve. The bill would open the land up for natural gas development under a system of competitive bidding among private companies. As discussed on page 2-17, the land is currently managed by the United States Department of Energy.

Moratorium Put on Patenting of Oil Shale Lands

As part of the effort to resolve the controversy surrounding the patenting process for oil shale lands in Colorado, Utah and Wyoming, a 1 year moratorium has been placed on such patents. At issue is the patenting of oil shale claims for as little as $2.50 per acre and then transferring ownership at much higher prices. As detailed on page 2-17, the moratorium will allow time for Congress and the United States Interior Department to continue negotiations to resolve the issue.

OSLO Winding Down

After 2 years of study, the six partners in the proposed OSLO oil sands project in northern Alberta, Canada are in the process of winding down their operations. As discussed on page 3-1, the OSLO consortium has decided it can go no further without government support. Construction of the C$4.5 billion project is likely to be delayed until 2000 or 2005. Project startup was originally planned for 1996.

Solv-Ex Still Looking for Financing for Bitumount Project

Solv-Ex Corporation is still seeking funding to develop the Bitumount Lease in Alberta, Canada. Solv-Ex plans to use its bitumen extraction process that combines continuous solvent extraction and hot water treatment of oil sands without air flotation. The process, the company's pilot plant and the proposed modular Lease Evaluation Unit are described in detail on page 3-4. The Lease Evaluation Unit is estimated to cost $12 million and will be used to obtain data for the design of a commercial extraction plant.
Petro-Canada Sells Part of Syncrude Interest to Mitsubishi

Mitsubishi Oil Company has agreed to purchase a 5 percent interest in the Syncrude oil sands project at a cost of $132.5 million. Petro-Canada will sell a 5 percent share of the project to Mitsubishi, but will continue to own a 12 percent share in the project. Details of the purchase agreement are discussed on page 3-6, as are the financial results for Petro-Canada for the first three quarters of 1991. After an initial public offering of common shares in July, Petro-Canada is 19.5 percent publicly owned.

DOE Calls for Advanced Oil Recovery Proposals

In October, the United States Department of Energy issued its first call for proposals for oil field demonstration projects. As discussed on page 3-7, DOE projects that advanced production techniques applied to existing oil fields could add more than 3 million barrels per day of domestic oil production by the year 2010. DOE will share up to half the cost of selected projects, supplying up to $40 million in this first round of competition.

National Energy Board Predicts Increasing Bitumen Production

Canada's National Energy Board has released a new study that contains projections of the supply, demand and price of Canadian energy. Oil price sensitivity tests indicate that the outlook for frontier, synthetic crude oil and bitumen supply is particularly sensitive to the price of crude oil. The Board's projections are summarized in the article which begins on page 3-9.

Clean Coal Technology May Find Use in Heavy Oil Applications

According to the United States Department of Energy, research on clean coal technologies may be applicable to direct combustion of heavy and extra heavy crude oils as fuel for heat or power generation. Some of the clean coal technologies that would apply to heavy oil fuels are summarized in the article beginning on page 3-12. Of the four types of technologies available, combustion cleaning and post-combustion cleaning technologies are particularly applicable to heavy crudes.

Horizontal Wells Becoming Viable for Heavy Oil and Tar Sands

A review of the limited number of horizontal wells that have been drilled for producing heavy oil and tar sands is presented on page 3-14. In general, the application of horizontal wells for non-thermal heavy oil applications appears to be economically viable, whereas the use of steam in conjunction with horizontal wells shows mixed economic results. A number of the parameters that determine the economic success of these wells are outlined.

VCC Technology Ready for Commercialization

After 10 years of intensive development work, the Veba-Combi-Cracking (VCC) technology is ready for commercialization. The basic principles of the VCC process are described on page 3-17. In 1988, the Bottrop Coal Liquefaction Plant was modified into a VCC plant and has since converted some 210,000 tons of vacuum bottoms into 180,000 tons of synthetic crude oil. Waste materials, including PCBs, can also be recycled via the VCC process.

Nigeria Tar Sands May Be Developed

A discussion of the prospects for developing the Agbabu bitumen deposit in southwestern Nigeria begins on page 3-20. Based on existing technology, the total recoverable oil in this deposit is es-
timated at 1,022 million barrels. A committee set up by the Nigerian Government to implement the bitumen project is currently holding discussions with several potential investors who have shown an interest in the commercial exploitation of the resource.

Orimulsion Making Progress in European Markets

BP BITOR, a joint venture formed to market Orimulsion, has lined up long-term contracts to deliver more than 9 million tonnes of the product per year. In Italy, ENEL alone will purchase 1 million tonnes of Orimulsion per year. As detailed on page 3-21, the first major trial of Orimulsion in Western Europe was in a 500-megawatt unit in the United Kingdom in 1989. A discussion of the performance and environmental characteristics of Orimulsion is also presented.

AOSTRA Annual Report Outlines International Efforts in Heavy Oil and Oil Sands

AOSTRA continued an active international program in 1990/991, signing memoranda of understanding with Argentina, China (SINOPEC), Japan, Azerbaijan and Kazakhstan. In addition, negotiations are under way with Nigeria, Brazil, Ecuador, India and Albania. An overview of AOSTRA's international activities in heavy oil and oil sands is presented in the article which begins on page 3-22.

Soviet Production of Natural Bitumen and Bituminous Rocks Covers 20 years

Natural bitumens and bitumen-containing rocks have been the subject of research and development activities in the Soviet Union for at least 20 years. The article on page 3-25 discusses the Soviet resource base for these materials and recent research trends, including in situ recovery techniques, mining techniques and mine-assisted gravity drainage techniques. In the Soviet Union a large portion of excavated bitumen-containing rocks are utilized for road paving, saving an estimated 5,000 rubles per kilometer of roadway.

Taciuk Process Finds New Environmental Applications

A comprehensive pilot program to demonstrate the ability of the AOSTRA Taciuk Process to treat heavy oil production wastes is described in the article beginning on page 3-28. A total of 17 different heavy oil wastes were tested in Phase I of the program. Phase II involved processing four separate bulk samples of oily wastes. A combined total of 380 tonnes were processed during 230 hours of operation in the continuous flow pilot plant. Discussed also are the costs of such treatment and disposal.

Wabash River Project Will Demonstrate Coal Gasification Repowering

Funding under Round 4 of the United States Department of Energy's Clean Coal Technology Program will enable Destec Energy and PSI Energy to demonstrate coal gasification repowering of an existing generating unit affected by the 1990 Clean Air Act Amendments. The project will incorporate a number of novel technologies in repowering the existing Unit 1 steam turbine. As detailed on page 4-1, the coal gasification combined cycle power plant will produce 265 net megawatts of electrical power using high-sulfur coal.

CTC to Test Char in Electric Arc Furnace

Coal Technology Corporation (CTC) is making experimental test runs using char for steel making in a full scale electric arc furnace, as discussed on page 4-3. The char will come from CTC's continuous mild gasification unit, which was completed last February. The char has about the same
fixed carbon, volatile matter and ash content as anthracite, but may be even better in an electric furnace because of its greater reactivity.

**MTCI Indirect Gasifier Yields High Hydrogen Concentration**

Manufacturing and Technology Conversion International (MTCI) has developed an indirect gasification process to provide cost effective hydrogen production from raw coal, mild gasification char, or ash residues. Tests have demonstrated that the MTCI technology has a high hydrogen gas yield. The process, which is discussed on page 4-10, promises to reduce capital and operating costs by 30 to 40 percent over oxygen-blown gasifiers.

**TECO Energy Relocates Round 3 IGCC Project**

TECO Energy's Round 3 Clean Coal Technology project, originally planned for Tallahassee, Florida, has been relocated to a site in Polk County, Florida. With approval from the United States Department of Energy, TECO Energy is proceeding with plans to install an integrated gasification combined cycle into Tampa Electric Company's planned 220 megawatt expansion project. A summary of the project is provided on page 4-13. The site change is not expected to affect the project's schedule.

**Eastman Expands Chemicals from Coal**

Eastman Chemical Company has doubled its production of methyl acetate, acetic acid, and acetic anhydride with the construction of a $200 million expansion of its coal facility in Kingsport, Tennessee. Eastman has worked for 10 years to identify, develop and assemble the numerous technologies necessary for a viable commercial venture. As detailed on page 4-14, Eastman says acetic anhydride is the key product in their new generation of coal-derived chemicals.

**UCG Project Proposed for Pennsylvania Anthracite Region**

Energy International Corporation (EI) is proposing an underground coal gasification (UCG) project in the anthracite coal region of northeastern Pennsylvania. Coal deposited in steeply dipping beds is most suitable for UCG, as demonstrated at a test site near Rawlins, Wyoming. A discussion of UCG technology, the anthracite resource, and the potential for commercialization is provided on page 4-17.

**Joint Research Teams Attack Oil from Coal Challenge**

Five research teams will embark on an intensive 2-year research effort to apply recent technological advances in an attempt to cut the cost of making liquid petroleum substitutes from coal, at the request of the United States Department of Energy. The goal of the effort is to reach the $30 per barrel mark. The five teams will share in about $5 million in federal research funds. The focus of each of the research teams is summarized on page 4-18.

**Nine New Clean Coal Projects Selected**

The United States Department of Energy has selected nine new projects under Round 4 of its Clean Coal Technology Program. The selected projects have a combined value of nearly $1.5 billion. The projects include three large-scale, high efficiency electricity generating projects, four demonstrations of high-performance pollution control devices and two techniques to change coal into new, cleaner burning fuel forms. See page 4-24 for a brief summary of each of the nine projects.
DOE Tells Congress No Additional Work Needed on Coal Refineries

In a recent report prepared for Congress, the United States Department of Energy identifies the research and development needs of coal refineries but concludes that programs already in place are filling those needs. The report identifies and discusses 27 coal refinery concepts in the following four categories: devolatilization, gasification, liquefaction and bioprocessing. A summary of the report appears on page 4-26.

Two SBIR Grants Given for Coal Liquefaction

Under Phase I of its Small Business Innovation Research (SBIR) program, the United States Department of Energy has awarded grants for two coal liquefaction technologies. As discussed on page 4-31, Advanced Fuel Research, Inc. received a $49,954 grant for development of online diagnostic techniques. Engineering Resources, Inc., with a $50,000 grant, will develop a process for the bioconversion of coal syngas to fuel oxygenates.

CERI Sees Big Role for IGCC in Canada

A study for the Canadian Energy Research Institute (CERI) says that integrated gasification combined cycle offers a combination of advantages which no other coal-based system can match. In Canada, IGCC is under active investigation in Nova Scotia, New Brunswick, Ontario, Saskatchewan and Alberta. IGCC applications and Canadian IGCC efforts are outlined in the article on page 4-33.

Mild Gasification to Produce Formcoke in Pennsylvania Shows Promise

An economic evaluation of the production of coke from coal using mild gasification process technology coupled with formcoke production is presented on page 4-36. The study results show that a mild gasification process installed at an existing power station will result in significant capital and operating cost savings as compared to a greenfield installation. The produced formcoke can be sold at competitive prices with significant internal rates of return.

ENCOAL Solid Product Shows Favorable Combustion Properties

ENCOAL's solid process derived fuel (PDF) obtained from the liquids from coal process has desirable handling, storage, combustion and utilization properties. A preliminary evaluation of the combustibility characteristics of PDF was carried out in a 600,000 BTU per hour pilot test facility. As detailed on page 4-41, the key properties examined included PDF flame visual appearance, stability at the burner and completeness of combustion.

Vortex Fluidized Bed Gasifier Under Development

The York-Shipley Division of DONLEE Technologies is developing an advanced substoichiometric precombustor for removing sulfur by sorbent injection and producing a combustible gas. The concept, described on page 4-43, is based on an advanced Vortex fluidized bed combustion technology. The concept was evaluated in a 4 million BTU per hour laboratory unit.

Advantages Seen for COREX Process

After analyzing various means to reduce emissions while increasing productivity, a team of engineers at Geneva Steel determined that the most viable and environmentally acceptable process is the COREX process. Geneva Steel compared eight scenarios, projected over an operating period
of 10 years, and found that the COREX scenarios were the lowest in cost. Additional advantages of the process are described on page 4-45.

Coal Hydrogen Controls Catalyst Deactivation in HRI Coprocessing

According to findings presented on page 4-48, catalyst deactivation in coal/oil coprocessing can be controlled by selecting coals with high hydrogen content. Coprocessing higher hydrogen content feedstocks can reduce the average catalyst deactivation rate by half. Researchers at Hydrocarbon Research Inc. (HRI) also studied the effects of selected operating conditions and catalyst cascading on the catalyst deactivation rate.

IGCC Based on Biomass and Peat Under Study in Finland

Fuel peat and wood wastes currently provide about 19 percent of Finland’s primary energy, the equivalent of about 5 million metric tons of oil per year. In the late 1980s, Finland’s government began funding research on the utilization of these widely available fuels in integrated gasification combined cycle power plants. The article beginning on page 4-51 presents a summary of the various projects undertaken to date in this area.

CIAB Sees Opportunity to Reduce Carbon Dioxide Emissions from Coal

A technical report from the Coal Industry Advisory Board (CIAB) says there are substantial opportunities to reduce emissions of CO₂ through improved efficiency of coal utilization and by applying state-of-the-art technology, particularly in developing countries. The report provides a comparison of the power generation efficiencies of commercially advanced, imminent and developing coal utilization technologies. The report is summarized on page 4-56.

DOE Outlines Proposals to Help Gas Industry

United States Department of Energy Deputy Secretary W.H. Moore outlined a series of proposals to encourage the use of natural gas as an alternative to imported oil. His proposals are outlined on page 5-2. Moore stated that Senate energy bill S.1220 will create more than 300,000 new jobs by the year 2000 and add over $550 billion to real gross national product through 2010. He also announced that all DOE facilities have been switched to natural gas.

Liquid Fuels from Natural Gas Should be Competitive at Oil Prices of $25 to $30

A review of the outlook for liquid fuels from natural gas is given on page 5-4. A number of petrochemical firms are committing substantial amounts of research and development funds to developing technologies to convert gas feedstocks into useful chemicals, including lower olefins, fuels and aromatics. An analysis of Mobil’s process to convert methanol to gasoline shows it is likely to be economic at oil prices of $30 per barrel if operated on a large scale.

Exxon Develops New Process for Synthetic Liquids from Gas

A 10-year, $100 million research and development program at Exxon has resulted in a new process to make synthetic liquid fuels from natural gas. In the process, which is described on page 5-5, natural gas is first converted to a synthesis gas, then to an intermediate hydrocarbon product, and finally to a high-quality liquid. The liquid product is suitable for use as a refinery feedstock, a range of end-use fuel products, petroleum specialty products and petrochemical products.
syn-fuels: general
CSIRO CONTINUES STRONG LIQUID FUELS PROGRAM

Australia's indigenous crude oil currently meets over 90 percent of the country's demand for oil, but CSIRO says this level of self-sufficiency could fall to less than 50 percent within 10 years.

The 1990 Annual Report from CSIRO's Coal and Energy Technology Division says that in the long term, it will be necessary to move to alternative fuels. The report points out the need to develop economic processes to produce synthetic fuels.

The division has, therefore, established a program to improve the processes and equipment used to produce liquid and gaseous fuels from sources other than crude oil.

Compressed Natural Gas

Compressed natural gas (CNG) can be used as a substitute for gasoline and diesel fuels in vehicles without requiring major engine modifications. CSIRO is investigating methods to overcome problems associated with the limited onboard storage capacity of existing cylinders both through the development of high surface-area materials with a high adsorption capacity (activated carbons) and through the use of solvents.

In 1990 CSIRO made significant advances in the preparation of activated carbon using various precursor materials including coal and coconut shell. Storage capacities were improved by a factor of 2.8 for a given volume and pressure.

The report says that in Australia there is a great incentive to develop simple processes, which can be located in remote or offshore locations, to convert natural gas to an easily transportable liquid. Economic conversion processes for natural gas would make it an attractive alternative source for transportation fuels.

Indirect Conversion of Natural Gas

Conventional natural gas conversion technologies involve the intermediate production of synthesis gas (syngas), a mixture of carbon monoxide and hydrogen.

CSIRO's work on this process is directed towards the development of improved reactor systems and catalysts. Past work has shown that three-phase slurry reactors overcome many of the problems arising from poor heat transfer in traditional fixed-bed reactors. The most recent catalyst testing program showed cobalt-based catalysts to be better suited to natural gas-derived syngas than the iron-based catalysts used with coal-derived syngas.

One problem of operating conversion plants in remote natural gas fields is that the simplified processes used in these locations result in the syngas having higher levels of impurities. Current research is therefore directed to developing catalysts which will have performance characteristics suited to these conditions.

New initiatives include the development of low temperature processes for the production of methanol syngas.

Direct Conversion of Natural Gas

The economics of indirect conversion processes are strongly dependent on the cost of the syngas, which may be 60 to 70 percent of the total cost. A recent demonstration has shown that it may be possible to by-pass syngas production, and convert methane directly to either ethylene or methanol.

Routes currently under investigation, which eliminate the reforming step altogether, include oxidative coupling and direct partial oxidation. CSIRO is developing basic oxide catalysts which allow the production of ethane and ethylene by the oxidative coupling process. Recent work has achieved a high proportion of the desired products, e.g., ethane, ethylene, propylene and propane, but, to be economically viable, these selectivities have to be maintained in high pressure reactors. This is the focus of work in 1991.

While direct partial oxidation is potentially a highly efficient route to methanol, the chemistry of the process is poorly understood, says the report. Current work is directed towards investigating this reaction in catalytic and non-catalytic reactor systems.

Oil Shale Conversion

Oil shale represents the other major thrust of the division’s research into conversion technologies. Over the past year engineering studies concentrated on recycled-solids processing. Researchers are testing a range of process variables using the newly-constructed integrated bench-scale facility which allows simulation of conditions which would be encountered in a commercial process. Future research will investigate if recycling the heavier fraction of the oil to the retort will efficiently break it to lighter fractions, which would ultimately reduce the amount of upgrading required.

The division's upgrading project is determining the optimum process conditions to produce acceptable gasoline feedstock, jet and automotive distillate fuels. Work thus far shows that suitable quality fuels can be produced using much less severe conditions, and therefore can be produced more cheaply, than has previously been envisaged.
In addition, CSIRO is applying for a patent for a novel process in which hydrogen-rich gas is produced as a byproduct of oil shale conversion. The process also has the potential to reduce costs involved with the safe, and environmentally acceptable disposal of gaseous, liquid and solid wastes.

The decomposition of clay and siderite minerals within the shale affects the heat requirements and the sulfur gas emissions associated with the retorting and combustion processes. A current project is determining the variations in mineralogy within shale deposits, defining the potential benefits of controlling endothermic reactions caused by decomposition and examining the effects of minerals on oil yield and quality.

Endothermic Fuels

CSIRO is developing processes to produce endothermic (heat absorbing) fuels for advanced high-speed aircraft. This project draws on the division's skills in high pressure reforming catalyst technology and is being carried out under contract to the General Electric Company Ltd.

Multi-Phase Systems

Researchers are using neutron-based techniques to study the flow and distribution of reactants and catalysts within high pressure vessels. Previous studies have been made in pilot-scale coal liquefaction plants and in various petroleum refinery operations, and CSIRO is now generating data under more controlled conditions to establish precise correlations.

###
DOE FOSSIL ENERGY BUDGET HOLDS ITS GROUND

The United States Department of Energy's (DOE) budget for fossil energy research and development (R&D) for fiscal year 1992 totals $449.6 million, a slight decrease from the fiscal year 1991 budget amount of $463.4 million. Table 1 (on the next two pages) gives a breakdown of budget categories for 1992 along with those from 1991 for purposes of comparison.

Coal

The 1992 budget for coal research and development is $276.5 million, a reduction of $12.6 million from the 1991 budget amount. This funding decrease is spread fairly uniformly across all budget categories with some notable exceptions.

The budget for research and development on coal preparation technologies was reduced by nearly $5 million from 1991 funding levels, while flue gas cleanup technology development funding was increased slightly by $0.5 million.

Funding for fuel cell research and development was increased by nearly $8 million over 1991 budget levels to $50.8 million, compared to $42.9 million in 1991. In addition, funding levels for specific research areas shifted dramatically.

In the area of fuel cells, research and development of phosphoric acid systems was de-emphasized while R&D on molten carbonate systems will be greatly accelerated. The budget for phosphoric acid systems was cut to $3.9 million from the 1991 budget amount of $8.9 million, a $5 million decrease. The 1992 budget amount for molten carbonate systems, on the other hand, received a $10.2 million increase to $28.6 million, compared to $18.4 million in 1991.

The overall 1992 budget for surface coal gasification R&D was cut by slightly more than $4 million from 1991 spending levels. The largest budget cuts were in the areas of systems for power production and systems for coproducts production.

Petroleum

The total R&D budget for petroleum was increased over those amounts budgeted in 1991. The area of geological sciences and extraction research received an increase of $3.5 million from funding of $3.8 million in 1991 to $7.3 million in 1992.

The emphasis on enhanced oil recovery (EOR) research and development remains high. Heavy oil EOR R&D funding was increased by $1.2 million while light oil EOR activities received a $3.9 million increase in the 1992 budget.

However, funding for tar sands EOR research was cut by $300,000 from $1 million in 1991 to $700,000 in 1992.

Oil Shale

DOE's budget for oil shale research and development was significantly reduced. The 1992 budget amount of $5.9 million reflects a funding cut of $11.3 million from the 1991 budget amount of $17.2 million.

Fossil Energy Environmental Restoration

DOE's 1992 budget for fossil energy environmental restoration is $11.4 million compared to the 1991 funding amount of $700,000. This $10.7 million increase reflects a growing concern in the United States about environmental stewardship and consequences for environmental irresponsibility.

NEW SBIR SOLICITATION COVERS ALTERNATIVE FUELS

The United States Department of Energy (DOE) has invited small business firms to submit grant applications under its tenth annual solicitation for the Small Business Innovation Research (SBIR) program. Under Phase I, DOE anticipates making approximately 150 grant awards in amounts up to $50,000 for projects of about 6 months duration.

A selected listing of technical topics for this solicitation is described below. A number of these topics include processes for producing, improving and enhancing utilization of alternative fuels.

Magnetohydrodynamics (MHD)

The ultimate commercial application of magnetohydrodynamic power generation could be accelerated by the development of advanced high temperature materials and new instrumentation, and by innovative MHD approaches that could advance the understanding of complex MHD electrodynamic and gasdynamic phenomena.

Grant applications are sought for the development of advanced materials, including novel composites of ceramics, metals, and ceramics/metal materials that would resist corrosion and erosion, e.g., electrodes, insulators, high temperature air heater elements; and innovative MHD systems and the special ancillary equipment needed for the operation of such systems.

SYNTHETIC FUELS REPORT, DECEMBER 1991
<table>
<thead>
<tr>
<th>Category</th>
<th>FY1991</th>
<th>FY1992</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>I. Coal</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A. Control Technology &amp; Coal Preparation</td>
<td></td>
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</tr>
<tr>
<td>1. Advanced Research</td>
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<tr>
<td>2. Coal Preparation</td>
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<td>3. Flue Gas Clean-Up</td>
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<td>5. Waste Management</td>
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<td>$50.6</td>
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<tr>
<td>B. Advanced Research &amp; Technology Development</td>
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</tr>
<tr>
<td>1. Coal Utilization Sciences</td>
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<tr>
<td>2. Materials &amp; Components</td>
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<td>9.2</td>
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<td>3. Technology Crosscut</td>
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<td>10.9</td>
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<td>4. University/National Labs Coal Research</td>
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<td>3. Indirect Liquefaction</td>
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<td>4. Support Studies &amp; Engrg. Evaluations</td>
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<td>Subtotal Coal Liquefaction</td>
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<td>D. Combustion Systems</td>
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<td>2. Atmospheric Fluidized Bed Combustion</td>
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<td>3. Pressurized Fluidized Bed Combustion</td>
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<td>4. Advanced Combustion Technology</td>
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<td>5. Alternative Fuels Utilization</td>
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<td>E. Fuel Cells</td>
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<td>F. Heat Engines</td>
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<td>I. Surface Coal Gasification</td>
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<td>3. Systems for Indus. Fuel Gas Production</td>
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<td>5. Systems for Coproducts Production</td>
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<td>4.4</td>
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<td>6. Great Plains Gasification Project</td>
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<td>Total Coal</td>
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</table>
TABLE I (Continued)

II. Petroleum

A. Advanced Extraction & Process Technology
   1. Arctic/Offshore Research  
   2. Geo Sci./Extract. Research  $5.0  $6.0
   3. SPT Tech./Environ. Research 3.8  7.3
   4. Univ. Geoscience Research 1.3  1.0
   Subtotal Advanced Extraction & Process Technology $10.1  $14.3

B. Enhanced Oil Recovery
   1. Heavy Oil  $4.7  $5.9
   2. Light Oil 26.0  29.9
   3. Tar Sands 1.0  0.7
   Subtotal Enhanced Oil Recovery $31.7  $36.5

C. Oil Shale  $17.2  $5.9

Total Petroleum $59.0  $56.7

III. Gas

A. Unconventional Gas Recovery  $15.9  $12.4

IV. Program Direction & Management Support  68.1  68.4

V. Plant & Capital Equipment  15.8  10.4

VI. Fossil Energy Environmental Restoration 0.7  11.4

VII. Cooperative R&D  11.9  10.7

VIII. Fuels Conversion, Natural Gas & Electricity 2.9  3.1

Total Fossil Energy Research & Development $463.4  $449.6

Source: U.S. Department of Energy

Innovative Coal Utilization Technology for CO₂ Management

Grant applications are sought for innovative system approaches that propose to reduce the CO₂ discharged to the atmosphere per unit of energy produced. Areas of interest include approaches that offer to substantially increase overall system efficiency, and/or provide for conversion, storage, or disposal of CO₂.

Advanced Coal Gasification Systems for Power

Applications are invited for innovative combined cycle power generation systems utilizing full or partial coal gasification. Concepts are sought to improve the net plant efficiency, reduce the cost, and enhance the environmental performance of power systems based on coal gasification. Possible approaches include novel coal gasification catalysts, in situ control of sulfur and nitrogen species, and control of trace contaminants.

Advanced Gas Turbine and Diesel Systems

The heat engines technical area includes both coal-fueled diesel engines and gas turbines. Grant applications are sought for novel integrated approaches for coal-fueled diesels to develop fuel injection techniques, so as to minimize erosion and improve atomization and combustion, and improve engine efficiency through in-cylinder techniques. Applications can address the use of coal-water slurries or micronized dry coal powder as a coal fuel.

Grant applications are also invited on novel approaches for coal-fueled gas turbines to develop innovative pressurized coal-fired combustors with inherent emission control capability, techniques for control of deposition, erosion, and...
corrosion in direct and/or indirect fired systems, or means to feed dry micronized coal to gas turbine combustors.

**High Performance Fuel Cell Systems**

Applications are sought for lowering the cost of fuel cells, improving the systems integration, and improving the resistance of the fuel cell components to gas stream contaminants. All fuel cell technologies will be considered.

Grant applications are invited in molten carbonate fuel cell technology in the following areas:

- Longer operating cell life with lower voltage decay rates
- Higher resistance to contaminants in the gas stream
- Higher power densities
- Unique, more efficient power generating systems from coal, tar sands, and oil shale to electricity

Grant applications are also sought in solid oxide fuel cell (SOFC) technology in the following areas: longer operating SOFC life with lower voltage decays, higher resistance to contaminants in the gas stream, higher power densities, lower operating temperature SOFCs, and unique cell configurations.

**Recovery of Heavy Oil**

According to DOE, two major problem areas in steam injection processes are excessive wellbore heat losses and low reservoir sweep efficiency. Grant applications are sought on novel techniques for steam processes to:

- Reduce wellbore heat losses using an effective, inexpensive insulating fluid in the tubing-casing annulus
- Improve the effective sweep of the reservoir during steam injection by reducing the effects of overriding gravity segregation, insufficient mobility control, and heterogeneities
- Recover the remaining oil left in the lower part of the reservoir after steam injection has been terminated

Research in reducing wellbore heat losses should not include insulated tubing or solid materials in the tubing-casing annulus. Research in improvements in reservoir sweep efficiency should not include conventionally used foams in steam flooding. Multiple injectants, either injected from the surface or created in situ, should be considered for mobility control.

**Conversion of Coal and Syngas to Liquids**

Applications are invited for research on innovative methods and concepts that will contribute to more efficient, effective, economic and environmentally acceptable techniques to produce coal-derived liquid substitutes for traditional petroleum products. Of particular importance are petroleum analogs that can be used for transportation fuels to lessen dependence on imported petroleum. Lacking are novel concepts that offer the possibility of improved coal liquefaction technology.

**Advanced concepts for conversion of coal to liquids are sought in the following areas:**

- Novel catalysts or reaction chemistry to remove oxygen in the initial stages of direct coal liquefaction with minimal or reduced hydrogen consumption
- Preconversion processing to minimize the occurrence of condensation/retrgressive reactions during the initial reaction stages of coal liquefaction
- The use of well dispersed (disposable) catalysts to promote more efficient conversion reactions

Indirect liquefaction of syngas consists of conversion of mixtures of carbon monoxide and hydrogen into liquid fuels. Applications are invited for:

- Novel single step processes for producing gasoline and diesel hydrocarbons
- Simpler routes to higher alcohols and ethers that can be used as octane enhancers
- Novel catalyst systems making use of modern methods of materials science to facilitate the desired reaction sequences
- Process schemes that make more effective use of heat generated in synthesis

Coal-oil coprocessing of heavy oil and coal is a promising new technique, says DOE. The production of liquid fuels by processing coal with heavy crude oil or refining residuum offers potential technical and economic advantages. Applications are sought for better understanding the chemistry of interaction between the residue and the coal, or improvements in demetalization.

**Innovative Technologies for Improved Efficiency**

DOE seeks grant applications for innovative methods and concepts that will allow improved efficiency in the utilization of coal and in coal processing (e.g., coal cleaning, coal con-
version, and coal micronization). Projects are sought that address various aspects of improved processes, process equipment, and materials to support and improve the overall coal fuel cycle from extraction to final new fuel form. These include optimal design of system components to increase capacity or efficiency and the replacement of standard valving and other components with new fluidics-based components and control systems.

Advanced Instrumentation and Computer Control

The operation of neural networks utilizes a computer architecture based on research into how the brain encodes and processes information, allowing it to reach conclusions faster, with fewer memory requirements and incomplete or fragmentary data. Functions important to operation and control systems include automatic extraction of information from large process operation data bases and the control of complex systems in real time.

Grant applications are sought on innovative uses of computer systems for data acquisition, decision making, real-time automation, and control that will be beneficial to operation, life extension, and environmental mitigation of coal fired powerplants and other coal utilization and processing systems. Under the general area of advanced instrumentation, only the following technical areas are to be addressed:

- Instrumentation for diagnostics, data acquisition, and control in the conversion of coal to liquids (liquefaction), advanced combustion systems, and magnetohydrodynamics research
- Flow instrumentation for multi-phase process streams
- Hot reaction zone data acquisition and control systems
- Online analysis of flue gas, as well as product and byproduct streams

Biotechnology Applications

Applications are sought on types of biotechnical resource modification that include conversion of fossil energy resources to liquid fuels, viscosity reduction of high viscosity materials, or release of organic materials bound in inorganic matrices. Applications are invited on microorganisms that have the ability to modify the structure of fossil energy resources and result in a fuel form that is more amenable to utilization, or requires minimum upgrading or processing.

Biocatalysts in nonaqueous systems and immobilized cell systems are also of interest. Projects are sought for research on the biochemical mechanisms by which these conversions occur.

Grant applications are also invited on improved approaches for bioprocessing fossil resources (or their products). Processes, processing systems, and processing equipment are all of interest, including novel and innovative techniques either to increase bioprocess efficiency or to improve bioreactor designs. These improvements could address bioconversion rates, design and characterization of bioreactor systems, optimization of bioprocessing conditions and reactors, or biological cleaning and upgrading of conversion products. Reactor subunits that have the capability of handling finely divided solids, or filamentous microorganisms, and which have an enhanced capability of removing other undesirable organisms are also of interest.

Advanced Concepts for Transportation and Utilization of Natural Gas, and Its Conversion to Liquid Fuels

Grant applications are invited for research on advanced concepts for economic transportation and utilization of natural gas, and its conversion to liquid fuels. The techniques sought for natural gas transportation or utilization include methodologies for recovering, utilizing, and transporting natural gas (including subquality or low-quality natural gas) from remote locations; and systems studies for optimizing natural gas utilization at the wellhead or for reducing the costs to the ultimate user of natural gas acquisition. The techniques sought for natural gas conversion to liquid fuels include catalytic and noncatalytic processes. DOE is interested in simplified processes for producing specialty chemicals or higher value hydrocarbons directly, and new or improved separation techniques to remove desired products from unconverted feedstock.

Coal-Based Mixtures

Coal-based mixtures can be formulated into fuels that have the potential to replace oil and gas in the utility, industrial, commercial, and residential market sectors. Applications are sought for the utilization of such coal-based mixtures.

Areas of interest include achieving a better understanding of coal surface chemistry and mixture rheology and providing for high solids loading, efficient atomization, or a more predictable mixture behavior from the standpoints of stability and controlled viscosity over extended time periods, without the need for constant monitoring and control. Projects are also sought that will improve the high-shear rheology of coal-based mixtures or investigate techniques, equipment, or additives that will improve atomization.

Coal-based solid mixtures can be utilized to meet SOx emissions regulations by blending two or more coals to achieve a specific sulfur content. Applications are sought to identify candidate coal blends that meet SOx requirements with minimal post-combustion emissions control, and characterize the physical, chemical, and combustion properties of selected coal blends to establish a database from which predictions of
system performance can be made when utilizing these blended coals.

Advanced Solids Transport

The goal of research in solids transport is to provide a sound theoretical base that will lead to improvements in the operability and cost effectiveness of emerging fossil energy technologies. Research on multi-phase and bulk solids flow, as related to fossil energy processes, is the main focus.

Innovative grant applications are sought for experimental work to elucidate basic characteristics and mechanisms of dense-phase fine particle flows. Applications are also invited on new diagnostic instrumentation that can measure fundamental parameters characterizing particle dynamics of solids/gas and solids/liquid systems. The proposed effort may include work considered to be applicable to specific kinds of flows found in fossil energy transport processes.

Advanced Fuels Characterization

Alternative coal-based fuels exhibit different behavior than conventional pulverized coal during the fuel utilization cycle. Grant applications are sought on advanced, novel techniques to characterize these alternative fuels, their combustion behavior, and resultant wastes and emission. Areas of interest include physical and chemical properties of ash, including morphology, optical properties, composition, deposition, and corrosion behavior; and fouling and slagging.

Improved Technology for Syncrude from Oil Shales

Shale oil continues to be a leading contender among competing synfuels. Improvements can be made in the entire oil shale process as follows: mining and material handling, retorting/extraction, and upgrading/refining. Applications are sought on methods to reduce the costs of mining, material handling, size reduction, and spent shale utilization or disposal.

The conventional method of converting the kerogen in the raw shale to oil is pyrolysis. Grant applications are invited on alternative cost effective approaches to kerogen conversion that minimize the production of gas and residual organic carbon (char), and maximize the production of oil. Projects are sought on novel methods of removing nitrogen, arsenic, and iron from raw shale oils. Also invited are applications on the removal of shale fines from raw shale oil, methods of minimizing hydrogen consumption in the upgrading/refining of raw shale oil, methods of enhancing the value of raw shale oil, and low cost methods of generating hydrogen for Eastern oil shale hydrotreating.

Improved Recovery Effectiveness in Tar Sands Reservoirs

According to DOE, two of the most difficult problems in the recovery of tar sands bitumen from reservoirs through the use of injected fluids are: low displacement efficiency and low volumetric sweep efficiency (areal and vertical) when a low-miscibility fluid is used. Grant applications are sought on novel techniques to accomplish more effective displacement and recovery of the heated or otherwise mobilized bitumen. These can include novel methods for reservoir heat application, or for establishing and maintaining communication. They can also include new approaches such as a combination of steam flooding, steam flooding with additives, in situ combustion, and other innovative processes. New ideas are also sought for surface extraction processes to recover tar sands bitumen.

Processes, techniques, and methods are being sought that reduce mined material handling and bitumen recovery costs and that embody environmentally acceptable waste disposal practices. Grant applications are invited for innovative approaches to advance resource utilization and cost effective process research and development.

Advanced Concepts for Mild Coal Gasification

Applications are sought for innovative concepts for producing coproducts using mild coal gasification. Such concepts can also include devices for in-process characterization of the products of mild coal gasification or methods to collect and separate the liquids produced in the mild gasification of coal. Concepts can also include processes to upgrade mild gasification char or liquids to commercial products.

Advanced Concepts for Low Cost Hydrogen

Applications are invited to develop advanced concepts for gasification of coal or coal char to produce low cost hydrogen. Concepts are sought that would increase efficiency, lower the amount of CO₂ produced, or improve bulk gas separations. Possible approaches include reducing the gasification temperature, decreasing the oxygen requirement, introduction of novel gasification catalysts, and production of hydrogen by biological techniques. Approaches could also include innovative methods for separation of bulk gases or contaminants such as sulfur species, or novel combinations of process steps into a single reactor, such as combining the catalytic water gas shift reaction with gas separation.

####

USA/USSR WORKSHOP ON FOSSIL ENERGY HELD

In early August, delegations from the United States, led by the Department of Energy (DOE), and the USSR, led by the State Fuel and Energy Commission, held a workshop to discuss the status of fossil energy technology and industry in the respective countries, as well as possible areas of cooperation on energy resources development. The objectives of the seminar were to establish a framework for technology...
cooperation and examine the expanding commercial opportunities between the United States private sector and republic governments and local enterprises in the USSR.

The workshop, which was organized by the United States Department of Energy, was held at the DOE Morgantown and Pittsburgh Energy Technology Centers.

The United States delegation to the workshop consisted of DOE officials and representatives of the technology centers.

The Soviet delegation consisted of representatives of fuel and energy industries from several of the major fuel producing republics.

In their presentations, the leaders of the United States and Soviet delegations expressed the need for further development and expansion of cooperation between the two countries in the area of non-nuclear energy. The leaders of the delegations expressed their satisfaction with the activity of both sides concerning the establishment of initiatives and creation of opportunities for cooperative energy-related research and development, and organization of information exchange on energy-related problems.

It was noted that additional efforts should be undertaken to establish commercial relations between republics and enterprises of the USSR and the private sector of the United States. The delegates expressed a desire to coordinate approaches used in development of national energy strategies, and combine efforts in the review and assessment of world energy problems.

During the workshop, both sides discussed the above issues in accordance with the established agenda, giving particular attention to modern energy technologies for oil and gas drilling and production, and new methods of oil and gas exploration.

The participants in the workshop heard overviews presented by the leaders of the ministries and enterprises of the Soviet Fuel and Energy Complex on the structure and supply and demand outlook for Soviet fuel and energy. Presentations were also given on new, environmentally acceptable technologies for coal burning at electric power plants and advanced methods of oil and gas exploration. Discussions were held on economic and legal considerations for the activities of private companies and joint ventures in the USSR and Soviet republics.

Both sides agreed that the objectives of the workshop had been met and committed themselves to holding periodic bilateral consultations to exchange information on energy policies and directions. Both sides also agreed to hold technology based exchanges between the central and republic government and enterprise levels in the USSR, and the government and private sector in the United States to advance efficient and environmentally safe developments in the areas of coal, oil and gas, and electric power generation.

The sides further agreed to carry out the following specific measures:

- Exchange information on approaches to the development of the respective national energy strategies, and recommend the establishment of a working group to compare energy data, analytical methods, results of research and policy recommendations, and alternative approaches to environmental issues.

- Develop a program of information exchange and assessments of oil and gas technologies, and share scientific studies aimed at their improvement for mutually beneficial utilization. This program may include personnel exchanges.

- A United States/USSR working group on oil and gas equipment sponsored a United States trade mission to the Soviet oil fields in October 1991. During this visit, the Soviet team and the United States equipment and service firms continued the discussion of opportunities for trade and joint ventures.

- Organize a technical working group comprised of government and industry representatives to exchange information and hold a workshop on clean coal technology research, development and demonstration in both countries.

- Establish a technical group to review the status of magnetohydrodynamics technology and develop recommendations for potential cooperation in this field.

- The DOE will explore the possibility of a fact-finding visit to the USSR in connection with mine safety requirements and approaches as practiced in the United States, with a view toward potential bilateral cooperation.

- Investigate the feasibility of a coordination mechanism for identifying and airing difficulties associated with emerging commercial projects where several Soviet entities may be involved or when other significant impediments are encountered.

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SYNTHETIC FUELS REPORT, DECEMBER 1991

1-9
ENERGY POLICY AND FORECASTS

POLITICS MORE IMPORTANT THAN ECONOMICS IN PROJECTING OIL MARKET

Conflicting political interests, manifested in the recent events in Iran, Iraq, Kuwait and the Soviet Union, will have far reaching future consequences for world oil markets. "Decisions by the major players will be heavily influenced by political considerations."

Speaking at the conference on Oil & Money held in London, England in November, C.H. Tahmassebi of Ashland Oil, Inc. said, "Oil market projections will require extensive knowledge of politics, not just economics and econometrics, and will be much more subjective and judgmental."

World oil markets will become more politicized not because of new political surprises, but because of the events that occurred in the period from 1978 to 1991. He said, however, that polarization and new groupings are unlikely to result in major regional or international conflicts.

According to Tahmassebi, the world economy will grow much more slowly due to heavy debt in major industrialized countries, shortage of capital, and smaller growth in labor productivity. The net economic impact of attempts to regionalize markets is not yet clear, but could be negative initially. Thus, some of the oil demand forecasts may prove to be too optimistic.

In addition, he says environmental regulation will inhibit demand growth. The United States 1990 Clean Air Act is estimated to cost industry $45 to $50 billion, and could add $0.15 to $0.20 per gallon ($6.30 to $8.40 per barrel) to gasoline costs. Similar regulations are expected elsewhere.

The result will be an increasingly tight refining capacity that is likely to widen the product-crude oil margins, which could intensify competition among crude oil suppliers.

Because most governments in industrialized countries are facing huge budget deficits, some are planning to raise consumption taxes, including those on oil and energy. Raising taxes on oil could also have political objectives; e.g., to reduce dependency on imported oil and vulnerability to supply disruptions.

On the other hand, says Tahmassebi, growing environmental concern and the continuation of a perceived threat of supply disruption are likely to result in new technological breakthroughs on the demand side. Any new consumption taxes will give additional impetus to this trend. In addition, new technologies (e.g., horizontal drilling) are being introduced on the supply side. Therefore, demand growth is expected to remain weak and new sources of supply are expected to come on stream even if oil prices remain low.

<table>
<thead>
<tr>
<th>Table 1 (on next page) gives the crude oil supply/demand outlook from Ashland Oil through the year 2000.</th>
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<tbody>
<tr>
<td>Capital and technological constraints are claimed to have limited the ability of some producing countries to raise production capacity, he says. To remedy this problem, these countries are providing new incentives for upstream investments. The result will be a production capacity increase and more stable prices.</td>
</tr>
<tr>
<td>A decline in United States production could lead to higher taxes and new policies aimed at more conservation and substitution. In addition, capital withdrawn from the United States is being invested overseas.</td>
</tr>
<tr>
<td>Soviet export capacity is bound to rise in the long run due to influx of capital, improved technology and rising energy efficiency. The net effect of developments in the United States and the Soviet Union could be neutral or even negative for world oil prices.</td>
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###

STUDY BY ENVIRONMENTAL GROUPS SUGGESTS ENERGY USE COULD BE CUT IN HALF

A new study says that the United States can cut its projected energy consumption nearly in half, quadruple its renewable energy use, and save consumers $2.3 trillion by 2030. The 2-year study, America's Energy Choices: Investing in a Strong Economy and a Clean Environment, is the work of scientists, engineers, and economists from the Natural Resources Defense Council, the American Council for an Energy-Efficient Economy, the Alliance to Save Energy, and the Union of Concerned Scientists.

The analysis evaluates more than 100 energy technologies in mapping out four possible energy futures for the United States: a reference case, reflecting current policies and trends; and three alternative scenarios designed to deliver the same quality of energy services as the reference scenario but at a lower cost and with less environmental damage. The alternative scenarios are: one designed to minimize costs to energy consumers (market scenario), one which assigns costs to the environmental impacts of energy use (environmental scenario), and one which seeks to meet predetermined targets for reducing carbon dioxide emissions (climate stabilization scenario).

The market, environmental and climate stabilization scenarios all lead to substantial reductions in energy requirements and pollutant emissions from the reference case.
TABLE 1
CRUDE OIL SUPPLY/DEMAND BALANCE OUTLOOK
(Million Barrels per Day)

<table>
<thead>
<tr>
<th>Baseline Scenario Projection</th>
<th>1990</th>
<th>1995</th>
<th>2000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>U.S.</td>
<td>17.2</td>
<td>17.5</td>
<td>18.0</td>
</tr>
<tr>
<td>Other</td>
<td>34.9</td>
<td>36.9</td>
<td>38.5</td>
</tr>
<tr>
<td>Total</td>
<td>52.1</td>
<td>54.4</td>
<td>56.5</td>
</tr>
<tr>
<td>Supply</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Inventory Adjustment:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NonOPEC Crude Oil &amp; NGL</td>
<td>25 - 26</td>
<td>24 - 26</td>
<td>22 - 24</td>
</tr>
<tr>
<td>CPE Net Export</td>
<td>2.0 - 23</td>
<td>1.8 - 20</td>
<td>1.5 - 2.0</td>
</tr>
<tr>
<td>OPEC NGL &amp; Processing Gain</td>
<td>2.6</td>
<td>2.8</td>
<td>3.0</td>
</tr>
<tr>
<td>OPEC Production</td>
<td>21.2 - 22.5</td>
<td>23.6 - 26.6</td>
<td>27.5 - 30.0</td>
</tr>
<tr>
<td>Total</td>
<td>52.1</td>
<td>54.4</td>
<td>56.5</td>
</tr>
<tr>
<td>OPEC Market Share</td>
<td>41 - 43%</td>
<td>43 - 47%</td>
<td>49 - 53%</td>
</tr>
<tr>
<td>OPEC Capacity</td>
<td>30</td>
<td>32</td>
<td>35</td>
</tr>
<tr>
<td>OPEC Operating Rate</td>
<td>71 - 75%</td>
<td>73 - 81%</td>
<td>79 - 86%</td>
</tr>
</tbody>
</table>

The results of the most aggressive case, the climate stabilization scenario, show that:

- National energy requirements in 2030 would be cut nearly in half from the reference case, with renewable energy sources providing more than half of United States energy supply.
- Carbon dioxide emissions would be cut by more than 25 percent from 1988 levels by 2005, and by more than 70 percent by 2030.
- Consumers would save $5 trillion in fuel and electricity costs over the next 40 years; subtracting the $2.7 trillion additional investment needed to achieve this, the result is an estimated net savings of $2.3 trillion.

The projections assume steady increases in the gross national product (GNP) throughout the 40-year span of the study. The dollar figures do not include indirect economic costs or indirect savings from reducing pollution. The report also presents suggested policies for the market, environmental, and climate stabilization scenarios.

The authors recommend three guiding principles for the United States to follow in adopting energy strategies that combine economic and environmental benefits:

- Harness market forces, such as using market incentives to promote efficiency and renewable energy sources and shifting some of the tax burden from income to pollution.
- Make efficiency the standard, such as increasing automobile fuel economy standards and setting building and equipment efficiency standards to minimize life-cycle costs.
- Invest in the future, such as giving energy-efficiency and renewables their "fair" share of federal research and development dollars and developing an integrated transportation network to increase access and cut congestion.

Description of Four Scenarios

The reference scenario, adapted from United States Department of Energy projections, represents a "business-as-usual" future which reflects expected GNP growth, changes in population, changes in energy prices, and underlying changes in energy use (including some energy efficiency improvements).

The market scenario includes only those technologies that are estimated to be cost-effective based on market prices and a 3 percent real (inflation-adjusted) discount rate. The
The performance and costs of fossil-fired technologies considered in this analysis are listed in Table 1. None of the scenarios include the construction of new nuclear reactors or the relicensing of existing reactors.

The data incorporate the assumption of a "societal discount rate" of 3 percent (inflation-adjusted), and the assumption of

TABLE 1

AVOIED POWER PLANT COSTS
(Cents per kWh in 1990 Dollars Levelized Over the Period 2010 to 2040)

<table>
<thead>
<tr>
<th>Heat Rate</th>
<th>Capital Cost</th>
<th>Add. Control Cost</th>
<th>Fuel Cost</th>
<th>O&amp;M Cost</th>
<th>Total Direct Costs</th>
<th>Air Emissions</th>
<th>Total Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>New Coal</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>AFBC</td>
<td>10.06</td>
<td>1.36</td>
<td>0.57</td>
<td>2.43</td>
<td>1.29</td>
<td>5.65</td>
<td>0.59</td>
</tr>
<tr>
<td>PBC</td>
<td>7.90</td>
<td>1.33</td>
<td>0.57</td>
<td>2.35</td>
<td>1.16</td>
<td>5.41</td>
<td>0.59</td>
</tr>
<tr>
<td>IGCC</td>
<td>9.22</td>
<td>1.32</td>
<td>0.27</td>
<td>2.23</td>
<td>0.91</td>
<td>4.73</td>
<td>0.22</td>
</tr>
<tr>
<td>MHD</td>
<td>6.40</td>
<td>1.13</td>
<td>-</td>
<td>1.55</td>
<td>1.14</td>
<td>3.82</td>
<td>0.02</td>
</tr>
<tr>
<td><strong>Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGCC</td>
<td>7.74</td>
<td>0.43</td>
<td>0.27</td>
<td>5.60</td>
<td>0.46</td>
<td>6.76</td>
<td>0.21</td>
</tr>
<tr>
<td>Fuel Cell</td>
<td>5.75</td>
<td>0.66</td>
<td>-</td>
<td>4.14</td>
<td>0.84</td>
<td>5.64</td>
<td>0.02</td>
</tr>
<tr>
<td>CFNG</td>
<td>9.43</td>
<td>1.53</td>
<td>2.24</td>
<td>6.82</td>
<td>0.86</td>
<td>11.4</td>
<td>0.58</td>
</tr>
<tr>
<td><strong>Oil</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CTDST</td>
<td>9.43</td>
<td>1.58</td>
<td>2.19</td>
<td>9.40</td>
<td>0.88</td>
<td>14.05</td>
<td></td>
</tr>
<tr>
<td><strong>Life Ext</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>10.0</td>
<td>0.19</td>
<td>-</td>
<td>2.41</td>
<td>0.80</td>
<td>3.40</td>
<td>1.19 - 2.10</td>
</tr>
<tr>
<td>Gas</td>
<td>10.0</td>
<td>0.10</td>
<td>-</td>
<td>7.23</td>
<td>0.40</td>
<td>7.73</td>
<td>0.75 - 1.15</td>
</tr>
<tr>
<td>Oil</td>
<td>10.0</td>
<td>0.13</td>
<td>-</td>
<td>7.56</td>
<td>0.40</td>
<td>8.09</td>
<td>0.69 - 2.41</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, DECEMBER 1991

1-12
an in-service date of 2010 in the derivation of levelized costs. The societal discount rate was adopted to reflect society's interest in reducing costs to future generations and in increasing long-term investment. Combined with the assumption of no taxes in capital recovery leads to a 5 percent levelized fixed charge rate for a 30-year investment rather than the more typical value of 10 to 12 percent. Together, these factors tend to increase the importance of fuel costs relative to capital costs. For example, a pressurized fluidized bed coal plant appears to be a more attractive investment than the natural gas combined cycle plant for the post-2010 period, whereas the reverse is true if a 1990 in-service date and a private perspective is assumed.

Reference Scenario

Reference case projections for electricity supply begin with the facilities that currently exist, and evolve to encompass load growth, plant retirements, and changes and additions in the mix of energy resources. The bulk of new baseload capacity added before 2010 use coal (150 gigawatts), whereas new natural gas combined-cycle facilities supply 55 gigawatts, and new wind, solar, wood and geothermal plants account for 27 gigawatts.

Existing nuclear power plants are assumed to be retired at the end of their normal lifetimes. In addition, all existing gas- and oil-fired steam-turbine units are assumed retired by 2030. Coal plants existing in 1988 are retrofitted to conform to recent amendments of the Clean Air Act; two-thirds of them are assumed to continue operation (with life extensions) through 2030, while the rest are retired between 2010 and 2030. Table 2 shows electricity generation by fuel type for the reference scenario through the year 2030.

TABLE 2
REFERENCE CASE ELECTRIC SUPPLY: GENERATION BY FACILITY TYPE
(1000 GWH)

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>1988</th>
<th>2000</th>
<th>2010</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1,598</td>
<td>1,897</td>
<td>2,632</td>
<td>3,970</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>276</td>
<td>565</td>
<td>598</td>
<td>648</td>
</tr>
<tr>
<td>Oil</td>
<td>142</td>
<td>224</td>
<td>142</td>
<td>27</td>
</tr>
<tr>
<td>Nuclear</td>
<td>531</td>
<td>563</td>
<td>536</td>
<td>32</td>
</tr>
<tr>
<td>Hydro</td>
<td>237</td>
<td>326</td>
<td>326</td>
<td>339</td>
</tr>
<tr>
<td>Solar</td>
<td>1</td>
<td>2</td>
<td>13</td>
<td>79</td>
</tr>
<tr>
<td>Biomass</td>
<td>33</td>
<td>76</td>
<td>113</td>
<td>126</td>
</tr>
<tr>
<td>Wind</td>
<td>3</td>
<td>5</td>
<td>17</td>
<td>83</td>
</tr>
<tr>
<td>Geothermal</td>
<td>30</td>
<td>33</td>
<td>53</td>
<td>112</td>
</tr>
<tr>
<td>Total Electric</td>
<td>2,851</td>
<td>3,691</td>
<td>4,430</td>
<td>5,416</td>
</tr>
</tbody>
</table>

Market Scenario

With the implementation of end-use efficiency measures, the need for capacity additions is greatly reduced in this scenario. Further, a greater portion of the new capacity is provided by renewable sources. The remaining baseload and peaking needs are met by essentially the same mix of resources as in the reference scenario. However, 10 percent of the baseload coal additions after 2010 are assumed to be advanced magnetohydrodynamic (MHD) or advanced fuel cells.

Environmental Scenario

The need for capacity additions is further reduced in the environmental scenario. Because of the inclusion of environmental costs in the price of coal, however, life extensions of coal plants are economically much less attractive, and consequently a larger fraction (two-thirds) of existing coal capacity are assumed to be retired by 2030. Twenty-five percent of new baseload coal additions after 2010 are assumed to be MHD or advanced fuel cells. Finally, renewable energy sources achieve much greater penetration, led by wind, solar, and geothermal.

Climate Stabilization Scenario

To meet the CO₂ reduction targets of this scenario, all existing coal-fired power plants are assumed to be retired between 1995 and 2030. About 25 gigawatts of electricity from MHD or advanced fuel cells come on-line after 2010. Almost all of the new baseload fossil units added before 2010, and all of the new units added thereafter, are natural gas combined cycle, natural gas steam-injected gas turbines, or natural gas fuel cell, resulting in a major shift in fossil fuel use and improved electricity conversion efficiency. Finally, the contributions of renewable energy sources increase even further, reaching 64 percent of total electricity generation and 73 percent of total electric capacity by 2030. Table 3 shows electricity generation by fuel type for this scenario through the year 2030.

Primary Energy Requirements

The reference scenario projects that the primary energy requirements of the United States will increase by about 41 percent during the next 40 years, from the 85 quadrillion BTU (quads) that the country required in 1988, to 120 quads in 2030. Oil consumption increases 15 percent over current levels. Although the amount of energy supplied by renewable sources in the reference scenario will double during the same period, the share of United States energy demand supplied by renewables increases only slightly, from 9 percent to about 13 percent. (See Figure 1 on page 1-15.)

In the market scenario, the United States' primary energy requirements fall sharply to 82 quads in 2030. This is
States' oil needs—7.1 million barrels per day (MMBD) out of total consumption of 16.9 MMBD. In less than 20 years, the United States could depend on foreign sources for almost 75 percent of its oil, says OTA.

But rising import dependence alone does not translate into a serious threat to energy security, according to OTA. Import vulnerability arises out of the degree and nature of import dependence, the potential harm to the economic and social welfare of a severe disruption in physical supplies or prices, its duration and the likelihood of such a disruption occurring. Along with diversifying world petroleum production and maintaining a viable domestic oil industry, the availability of technologies to offset lost imports helps to cut the risks of growing dependence on foreign oil and thus reduces import vulnerability.

The 1984 OTA study, which assumed a loss of 3 MMBD in United States oil imports for 5 years, looked at technologies for responding to a severe, long-lasting oil import disruption. OTA found at that time that an aggressive program of fuel switching, alternative fuels, conservation, and efficiency measures could replace 3.6 MMBD within 5 years.

World oil market conditions, however, have changed in the 7 years since the first OTA study. A comparable oil disruption scenario set in 1991—roughly equivalent to loss of Persian Gulf production—would involve a loss of 5 MMBD of United States oil imports for at least 5 years. OTA now estimates that aggressive deployment of available oil displacement technologies over 5 years could replace only about 2.9 MMBD of the 5 MMBD in lost imports. Moreover, this replacement potential must be discounted by the expected continuing decline in domestic crude oil production, yielding an effective net import replacement capability of from 1.7 to 2.8 MMBD. This implies a shortfall of 2.2 to 3.3 MMBD of lost oil imports under the OTA disruption scenario.

Reliance on oil replacement technologies is no longer sufficient to offset the threat of a major and prolonged oil supply disruption. According to OTA, this means that while many developments in world oil markets and politics have contributed to a lessening of probabilities that significant oil supply disruptions will occur, the United States' ability to respond to them has shrunk, leaving the country more vulnerable should a prolonged oil cutoff occur. Therefore, strategic oil reserves and advance preparations for oil supply emergencies will play a more important role in reducing oil import vulnerability than in the past.

Much could also be done to reduce projected growth of oil import dependence, OTA says. Examples of opportunities for use of oil-saving technologies found across the United States economy include: switching more residential, commercial, industrial oil use to electricity, natural gas, coal, or renewable fuels and improving the efficiency of remaining oil uses; increasing the fuel economy of light duty vehicles; and accelerating a transition to alternative transportation fuels.
The study presents a range of policy options for promoting the adoption of oil replacement technologies under two alternative strategies: responding to a severe import disruption; and limiting oil import vulnerability as part of long-term national energy policy objectives. Some policy options and technologies have fewer implementation problems and offer greater oil savings if adopted as part of a long-term oil replacement strategy rather than as part of a crisis-driven strategy, says OTA. This is particularly true for displacing oil use in the transportation sector.

Technical Replacement Capability

OTA found that the potential to replace lost oil imports through conservation, efficiency, and fuel switching is about 1.7 to 2.8 MMBD. Table 1 (see next page) shows the estimated oil replacement potential of various technologies under the updated oil disruption scenario. Figure 1 (see page 1-17) shows the rate of oil replacement by sector.

A vigorous effort to reduce oil use in the residential and commercial sectors by switching to natural gas, electricity, coal, and renewable fuels and by speeding the adoption of efficiency improvement measures could replace almost 1 MMBD, or about 72 percent of 1989 consumption, within 5 years. This would entail converting over 13.5 million homes and commercial buildings to natural gas or electric heat and hot water systems and converting 88,000 of the larger remaining commercial and residential heat systems to burn coal slurry fuels.

Electric utilities accounted for less than 5 percent of total oil consumption in 1989. OTA estimates that it is technically feasible to replace about 600,000 barrels per day, or over 80 percent of 1989 utility oil use within 5 years by fuel switching in existing dual fuel units, shifting generating loads to non-oil units where capacity permits, completing planned capacity now under construction, converting existing units to natural gas or coal, and installing new non-oil generating capacity, including renewable energy facilities.

OTA estimates that the industrial sector could technically displace about 800,000 barrels per day of petroleum products, or about 20 percent of its 1989 consumption. The oil replacement options in the industrial sector include credit for oil savings from reduced refinery throughput (360,000 barrels per day) and the savings that would result from switching to natural gas and other fuels for process heat, steam, and
TABLE 1
SUMMARY OF ESTIMATED OIL REPLACEMENT POTENTIAL, 1991

<table>
<thead>
<tr>
<th>Sector</th>
<th>Millions of Barrels per Day After 5 Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Utilities:</td>
<td></td>
</tr>
<tr>
<td>Convert/switch to coal</td>
<td>0.36</td>
</tr>
<tr>
<td>Switch to natural gas</td>
<td>0.09</td>
</tr>
<tr>
<td>Renewable fuels</td>
<td>0.10</td>
</tr>
<tr>
<td>Newly completed nuclear plants</td>
<td>0.04</td>
</tr>
<tr>
<td>Other new capacity and demand management</td>
<td>0.02</td>
</tr>
<tr>
<td>Subtotal</td>
<td>0.60</td>
</tr>
<tr>
<td>Industry:</td>
<td></td>
</tr>
<tr>
<td>Switch to natural gas</td>
<td>0.30</td>
</tr>
<tr>
<td>Convert/switch to coal, electricity, renewables</td>
<td>0.05</td>
</tr>
<tr>
<td>Process changes and increased efficiency</td>
<td>0.10</td>
</tr>
<tr>
<td>Reduced refinery throughput</td>
<td>0.36</td>
</tr>
<tr>
<td>Subtotal</td>
<td>0.80</td>
</tr>
<tr>
<td>Residential and Commercial:</td>
<td></td>
</tr>
<tr>
<td>Convert to natural gas</td>
<td>0.50</td>
</tr>
<tr>
<td>Convert to coal</td>
<td>0.06</td>
</tr>
<tr>
<td>Convert to electricity</td>
<td>0.40</td>
</tr>
<tr>
<td>Renewable fuels and efficiency improvements</td>
<td>0.05</td>
</tr>
<tr>
<td>Subtotal</td>
<td>1.00</td>
</tr>
<tr>
<td>Transportation:</td>
<td></td>
</tr>
<tr>
<td>Increased fuel economy in light-duty vehicles</td>
<td>0.30</td>
</tr>
<tr>
<td>Alternative vehicle fuels</td>
<td></td>
</tr>
<tr>
<td>Natural gas</td>
<td>0.13</td>
</tr>
<tr>
<td>Biomass fuels (ethanol)</td>
<td>0.03</td>
</tr>
<tr>
<td>Improved traffic management</td>
<td>0.10</td>
</tr>
<tr>
<td>Subtotal</td>
<td>0.60</td>
</tr>
<tr>
<td>Total replacement potential (all sectors)</td>
<td>2.95</td>
</tr>
<tr>
<td>Domestic petroleum supply (decline)</td>
<td>(0.1 - 1.2)</td>
</tr>
<tr>
<td>Effective technical replacement potential</td>
<td>1.7 - 2.8</td>
</tr>
</tbody>
</table>

power generation, and from intensifying the adoption of more energy-efficient processes in manufacturing. The major oil replacement potential in the industrial sector is in manufacturing.

The transportation sector is the United States economy's largest oil user, accounting for almost 63 percent of the nation's total oil consumption. The most promising opportunities for fuel savings in both the short- and long-term in this sector involve oil replacement options for automobiles and light trucks, says OTA. The major oil displacement opportunities are improved fuel efficiency, conversion of some fleet vehicles to natural gas and other alternate fuels, and better traffic management. OTA estimates that it is possible to displace about 555,000 barrels per day of petroleum products in the transportation sector within 5 years, or about 5 percent of 1989 consumption. This would be accomplished using existing technologies and with only minor shifts in customer preference or new-vehicle fleet mix.

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Other transportation sector measures adopted in response to an oil supply crisis would supply the remaining oil replacement potential, including:

- Converting 1.2 million existing fleet vehicles to run on natural gas
- Increasing use of ethanol and expanding production capacity
- Adopting various measures to improve traffic management to promote more efficient vehicle travel, cut vehicle miles traveled, and increase car pooling and reliance on public transportation

Declining domestic crude oil production threatens to exacerbate any oil import shortfall, says OTA. There is some potential for stemming this trend. Production from already discovered onshore and offshore fields, including increased infill drilling, delaying abandonment of existing wells, reopening shut-in production, and accelerating enhanced oil recovery, could contribute from about 170,000 to 510,000 barrels per day of additional crude oil supply. Expanded natural gas production could also add 100,000 to 200,000 barrels per day of natural gas plant liquids. But the expected decline in United States crude oil production could mean a loss of 400,000 to 1 million barrels per day resulting in an internal shortfall of 0.1 to 1.2 MMBD in addition to a 5 MMBD loss of imports.

Repeating Oil Use in a Severe Import Disruption

In an oil emergency, getting residential and commercial building owners to accelerate oil conversions and efficiency improvements in existing buildings will require a mix of information, exhortation, direct financial incentives, and voluntary and mandatory efficiency standards. Legislative options to foster oil savings include: taxes or surcharges on oil products and equipment, measures to reduce front-end-costs and cash flow barriers, financing assistance, efficiency standards, labeling and certification programs, public information, and technology R&D programs. Measures to improve local availability of natural gas would also help oil-to-gas conversions.

Most utilities now appear well situated to respond to an oil supply emergency. Nevertheless, there are several legislative actions that could further enhance oil displacement capability. Congress might, for example, require states to consider adopting regulatory policies that favor oil replacement technologies and efficiency improvements in planning, licensing, and rate matters and to prepare oil emergency contingency plans.

Because of the diversity of oil use in the industrial sector and the limited oil replacement alternatives available, this sector is highly sensitive to price signals. In an oil emergency, higher oil prices, coupled with concerns over the availability of oil products at any price, would probably trigger a high degree of oil replacement without any additional financial incentives, says OTA.

Cutting oil use by cars and light trucks offers the most significant opportunity for short-term oil savings in transportation. An aggressive oil replacement strategy would include four goals:

- Improving light-duty vehicle (LDV) fuel efficiency
- Accelerating the adoption of alternative non-oil transportation fuels and vehicles
- Limiting the increase in or cutting vehicle miles traveled
- Improving the efficiency of traffic movement

Policy options for improving LDV fuel efficiency include:

- Amending federal vehicle fuel efficiency standards to require new cars and light trucks to attain maximum fuel economy levels under available technology
- Using various market-oriented mechanisms to affect the front-end and life cycle costs of LDVs, based on the assumption that consumers will
choose more efficient vehicles in response to such price signals

- Requiring fleet operators (including federal agencies) to purchase more fuel-efficient vehicles

Shifting a portion of the LDV fleet to vehicles that run on alternative fuel requires:

- Manufacture or retrofit of alternative fuel vehicles in sufficient quantity
- The development of an adequate refueling and service support infrastructure
- Consumer acceptance

Oil replacement technologies can counter the effects of an oil import disruption, but will achieve their maximum replacement potential only if domestic production of oil is maintained at or near current levels and domestic natural gas production increases to meet new demand. Policy options that maintain domestic production and encourage oil and gas exploration and development are thus part of any oil replacement strategy, says the study.

Legislative options intended to encourage domestic exploration, development and production can be grouped as follows:

- Targeted tax incentives for exploration or production such as tax deductions, credits, and depletion allowances
- Measures that raise the price of oil or natural gas at the wellhead such as import fees or price floors
- Technical assistance and technology transfer programs
- Changes in the strategic petroleum reserve program to favor certain classes of domestic producers or to include preservation of domestic production potential
- Opening more federal onshore and offshore lands to leasing or adopting more favorable lease terms or royalties
- Resolving specific regulatory or environmental controversies that are delaying exploration, development, or production

Establishing National Energy Goals

According to OTA, the United States can ease oil import vulnerability by establishing long-term energy goals. Candidate goals for limiting oil import vulnerability, increasing energy efficiency, and beginning a long-term transition to a post-fossil economy by the year 2010 might include the following:

- Limiting net oil imports to not more than 50 percent of annual oil consumption
- Promoting efforts to diversify sources of world oil production in regions outside the Middle East
- Increasing energy efficiency by 20 percent per decade or an average of 2 percent per year
- Initiating a move towards a post-fossil economy in the long term by reducing carbon intensity by 10 percent in each of the next 2 decades
- Improving the efficiency of the transportation sector by increasing light-duty efficiency by an average of 2 percent per year
- Reducing oil's share of transportation energy use by 10 percent by 2010

###

ENERGY SECRETARY DECRIES FAILURE OF ENERGY STRATEGY BILL

In October the United States Senate refused to bring up for debate the Johnston-Wallop energy bill. This bill contained many of the key provisions of the National Energy Strategy (NES) developed by the Department of Energy over the last 2 or 3 years and released by President Bush in February 1991.

Secretary of Energy J.D. Watkins said that the Senate vote blocking consideration of a comprehensive energy bill "may end up costing 300,000 jobs and add billions to the trade deficit."

"This bill has conservation, it has efficiency, it has research and development, and it contains production. Every member of the United States Senate knows full well that this nation is not going to satisfy its thirst for energy on just conservation, just as each of them knows that no single oil or natural gas field or coal mine or nuclear power plant will. We need both conservation and production, because we know that one without the other just will not do the job," said Watkins.

The Energy Secretary said many of the provisions contained in the NES could be achieved without legislation. "This country desperately needs a national energy plan. The President can do part of the job through executive orders. The private sector can do part of the job. And the American people can do part of the job. But we are never going to get

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Watkins said energy imports account for more than 50 percent of the trade deficit, and cited a report from the Congressional Office of Technology Assessment that foreign oil imports will increase from the current 45 percent to an estimated 67 percent by the year 2010 because of increased demand for energy and steadily declining domestic oil production. "What the Senate did is vote down a jobs bill, a trade deficit bill, and an energy bill. I think they let the American people down in the process," he said.

###

**BP STATISTICAL REVIEW NOTES LACK OF GROWTH IN WORLD ENERGY RESERVES AND USE**

According to the British Petroleum Company (BP), after marked increases in the world's oil reserves since 1987, there was a slight drop in 1990 to 1,009 billion barrels. Figure 1 shows that worldwide proved oil reserves increased steadily from 1965 to 1972, mainly in the Middle East. The increase in 1987 occurred in the Middle East and Venezuela, while the 1989 increase was mainly attributable to Saudi Arabia. Reserves in the Middle East continue to grow and now represent 65.6 percent of the total worldwide.

As shown in Figure 2 (on the next page), North America's energy consumption on a per capita basis remains far higher than that of any other region. BP notes, however, that per capita consumption has increased significantly in the Soviet Union and Central European countries since 1965.

According to BP's "Statistical Review of World Energy," in 1990 the world consumed less oil for the first time since 1983. The report also states that overall energy demand rose only 0.4 percent in 1990, the slowest rate of increase since 1982. This trend was attributed to sluggish economic growth in the developed world and higher oil prices in the second half of the year.
FIGURE 2

PER CAPITA ENERGY CONSUMPTION

SOURCE: BP
FLEXIBLE FUEL CONVERSION PLANTS PROPOSED

"Flexible fuel conversion plants," capable of using any and all domestically available alternative fuels, would allow the transportation system in the United States to be based on domestic resources. At an imported crude price of about $30 per barrel, transportation fuels made from domestic resources would be cost competitive, according to J.P. Longwell, professor of chemical engineering at Massachusetts Institute of Technology.

Longwell's conclusion is based on resource and cost estimates gathered in a study that he led for the National Research Council (NRC), at the request of the United States Department of Energy. In that study, a committee of academic and industrial experts worked together to recommend strategic directions for a 4-year research and development program that would lead to production of liquid fuels from domestically available resources.

Table 1 shows estimated costs for converting "alternative" resources to liquid transportation fuels. Each cost is expressed in terms of an "equivalent crude cost," defined as the crude oil price at which the alternative resource becomes a cost-competitive feedstock for fuel production. The equivalent crude cost is the oil price at which it would be just as cheap to use the alternative resource to produce fuel as to use oil. Included in the calculations are investments for manufacturing and distribution facilities as well as the cost of vehicle modifications needed to accommodate the alternative fuel.

Heavy oil and tar sands could be converted to transportation fuels by hydropyrolysis at $25 per barrel and $28 per barrel equivalent crude cost, respectively. Equivalent crude costs for coal liquefaction and Western shale oil recovery are estimated at $38 per barrel and $43 per barrel, respectively. Continued research could reduce the costs for both of these processes to $30 per barrel within the next decade, says Longwell. The equivalent crude cost for using compressed natural gas as an automotive fuel is about $34 per barrel.

Gasifying coal to produce methanol would cost $35 to $40 per barrel. Using wood in place of the coal would produce methanol at about the same cost, as long as the processing plant is the same size.

The cost of making methanol from natural gas is highly sensitive to the price of the gas. At $3.00 per thousand cubic feet (Mcf), methanol from natural gas becomes roughly competitive with methanol from coal. But if crude oil costs more than $30 per barrel, natural gas would not be available domestically at that price. The estimates at $3.00 and $1.00 per Mcf therefore represent imported methanol.

Based on these resource and cost estimates, Longwell and his colleagues recommended "major funding" be allocated for three tasks:

- Improving the technology for oil and gas production to reduce costs and expand resource utilization
- Developing the technology needed to achieve the target price of $30 per barrel of oil equivalent for liquids from coal and Western oil shale
- Further investigating the impacts on health, safety, and air quality of using alternative fuels

Viewed from a broader perspective, Longwell notes that in the long term the costs for producing liquid fuels from the various resources are comparable. Based on that observation, he proposes a novel concept. Rather than working to develop fuel conversion plants for each type of resource, the focus should be on designing a plant that can use any and all of the domestically available resources interchangeably.

One of the biggest problems in converting carbon resources to desirable liquid fuels is that the conversion process itself consumes some fuel. Fuel conversion therefore increases the rate of resource depletion and lowers overall energy efficiency. In addition, it increases the amount of carbon dioxide (CO2) generated by fossil fuel use.

Table 1: Cost of alternative fuels

<table>
<thead>
<tr>
<th>Process</th>
<th>Equivalent Crude Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heavy Oil Conversion</td>
<td>$25</td>
</tr>
<tr>
<td>Tar Sands Extraction</td>
<td>28</td>
</tr>
<tr>
<td>Coal Liquefaction</td>
<td>38 (30*)</td>
</tr>
<tr>
<td>Western Shale Oil</td>
<td>43 (30*)</td>
</tr>
<tr>
<td>Compressed Natural Gas</td>
<td>34</td>
</tr>
<tr>
<td>Methanol via Coal Gasification</td>
<td>35 - 40</td>
</tr>
<tr>
<td>Methanol via Wood</td>
<td>35 - 40</td>
</tr>
<tr>
<td>Methanol via Natural Gas at $5.00/Mcf</td>
<td>46</td>
</tr>
<tr>
<td></td>
<td>$3.00/Mcf</td>
</tr>
<tr>
<td></td>
<td>$1.00/Mcf</td>
</tr>
</tbody>
</table>

*The NRC committee judged that a cost of $30 per barrel could be achieved through an intensive program of research and development.

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According to Longwell, the flexible fuel-conversion plants he proposes provide opportunities for dealing with those problems. For example, such plants would take full advantage of biomass resources, which are both renewable and CO₂ neutral. Because biomass supplies are generally limited and variable from season to season, plants that burn only biomass are typically too small to be economical.

Flexible fuel-conversion plants based on either indirect or direct conversion would be large. When biomass was available, it could be used in such plants efficiently and economically. When biomass was unavailable, other resources could quickly be substituted. In addition, biomass could be fired simultaneously with other fuels in such a plant.

Coal or oil shale could also be used with no additional CO₂ penalty. In indirect processing, most of the added CO₂ emissions come from the gasifier, where part of the fuel is burned to supply heat. The heat could instead be provided by sources such as solar, geothermal, or nuclear power. Likewise, the hydrogen required for direct conversion could be supplied not by gasifying hydrocarbon resources, but by splitting water using electricity from nuclear- or solar-powered generators. If such sources of heat and hydrogen were used, then no extra fossil fuels would be consumed and no extra CO₂ would be emitted.

According to Longwell, an environmentally acceptable version of the flexible fuel conversion plant could be built using existing technology. Gasifiers can be designed to handle diverse feedstocks with little or no loss of efficiency.

However, the capital cost of a flexible fuel conversion plant using current technology would be high. The resource estimates in the NRC study suggest that if research begins now, costs could be significantly reduced before the transition to alternative resources becomes imperative.

Longwell says the federal government should take responsibility for supporting this early work. The research program should include fossil fuels related work such as research and development to meet the cost targets for coal liquefaction and shale oil conversion. But it must also emphasize development of non-fossil sources of heat and hydrogen such as solar, geothermal, and nuclear power.

###
CONTINUATION OF AUSTRALIAN ENERGY EXPORTS RECOMMENDED

The Australian Minister for Resources, A. Griffiths, has released an energy policy statement: "Issues in Energy Policy—An Agenda for the 1990s." The statement says that Australia, one of the few OECD countries that is a net energy exporter, can achieve its national objectives best by being an efficient producer and exporter of energy.

"Neither Australia's interests nor global interests are served by limiting exports of the full range of fossil fuels. Limiting these exports can have the perverse effect of energy being supplied from more environmentally damaging sources."

Australia has large supplies of most energy resources but still depends on imports of oil. Table 1 lists Australian energy resources and production. With the exception of liquid petroleum, Australia is well endowed with energy resources. For this reason, the question of energy security for Australia is essentially about liquid fuel supplies.

Australia’s energy economy is diverse, with substitutes such as coal, electricity and gas for stationary end uses, and alternatives for liquid fuels in transportation such as liquefied petroleum gas and compressed natural gas.

Australia currently imports 280,000 barrels per day of crude oil and petroleum products and consumes 639,000 barrels per day. Australia has never been totally self-sufficient in crude oil because of the need to import about 100,000 barrels per day of heavier crude oil to meet the demand for products such as lubricants, bitumen and most grades of fuel oil. Australia’s production of light crudes, on the other hand, supports exports of around 173,000 barrels per day.

Disruptions to oil supply may occur at any time as the Middle East remains a volatile and high risk area. As a result of past experience, many countries have emergency arrangements in place, either individually or collectively or both, to cope with disruptions to oil supply. Australia has a number of domestic arrangements in place for oil supply disruptions.

According to the statement, responses to liquid fuel security and energy security in general are closely related to some of the broader long-term objectives of energy policy. Saving energy through efficient use and fuel switching measures, removing impediments to the efficient exploration and development of new supplies, and research and development into renewables and synthetic fuels, will contribute to the long-term stability and continued diversification of Australia’s energy supplies.

Australia’s energy security needs will best be met by a continuing commitment to ensuring a viable and dynamic energy sector. The efficient exploration and development of Australia’s petroleum resources must be emphasized and gains in efficiency pursued. The removal of impediments to the economic development of renewable energy supplies and fuel switching needs to continue, says Griffiths.

National Energy Policy

Present forecasts are that Australia’s role as a producer, consumer and trader of energy resources will increase over the next decade in response to rising domestic and international

TABLE 1

AUSTRALIAN ENERGY RESOURCES
(Thousands of Petajoules as of December 1989)

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Demonstrated Resources</th>
<th>Inferred Resources</th>
<th>Production 1989-90</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Economic</td>
<td>Sub-Economic</td>
<td>very large</td>
</tr>
<tr>
<td>Black coal</td>
<td>1,200</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Brown coal</td>
<td>414</td>
<td>26</td>
<td>1,820</td>
</tr>
<tr>
<td>Crude oil</td>
<td>14</td>
<td>2.7</td>
<td>na</td>
</tr>
<tr>
<td>Natural gas</td>
<td>37</td>
<td>46</td>
<td>na</td>
</tr>
<tr>
<td>LPG</td>
<td>3</td>
<td>1.3</td>
<td>na</td>
</tr>
<tr>
<td>Shale oil</td>
<td>-</td>
<td>168</td>
<td>1,506</td>
</tr>
<tr>
<td>Uranium</td>
<td>262</td>
<td>32</td>
<td>215</td>
</tr>
</tbody>
</table>

A petajoule is approximately equivalent to 170,000 barrels of oil.
energy requirements that cannot be met by alternative means within that time frame. However, ecologically sustainable development demands that energy production and use must be attuned to more environmentally acceptable outcomes.

In the 1990s, Australia must develop effective mechanisms to incorporate the costs of environmental damage, environmental risk or rehabilitation of the environment into energy costs and prices. These mechanisms will be a driving force for change, for efficiency and for sustainable development in the energy sector.

Continuing improvements in energy efficiency are necessary for sustainable energy production and use. Griffiths says that means four main changes:

- Removing distortions in energy product taxation and pricing, the transport sector being a priority area for attention
- Improving energy management and information programs to assist rational decision making
- Developing national energy standards, labeling, performance criteria and codes
- Undertaking energy research and development that paves the way to new, efficient and cleaner energy technology, including technology for renewable energy

A strategy is needed to ensure a rational approach to natural gas development in the 1990s. This strategy will have to reconcile the geographic dispersion of Australia’s natural gas resources with the concentration of rising demand in industry, power generation and households and the need to balance the requirements of Australian and export markets. It will have to examine the following issues:

- The scope for pipeline extensions and interconnections
- The best means of ensuring the orderly and efficient development of the gas industry
- How to better coordinate commonwealth, state and territory policies and regulatory systems

Expansion of Australia’s Energy Trade

For the foreseeable future, the global economy will depend on increasing quantities of energy supplied by traditional fossil fuels. The statement says that as a major and efficient supplier, Australia should seek to maximize its role in meeting international needs for these fuels. They will provide the bridge to a sustainable energy future as newer and more efficient technologies and fuels are developed.

For now, the main goal should be to ensure that international energy markets operate on a free, open and competitive basis. That will provide the most effective basis for production and use of existing energy resources and for new technologies and fuels as they develop.

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SYNTHETIC FUELS REPORT, DECEMBER 1991

1-24
COMING EVENTS

1992

JANUARY 26-29, HOUSTON, TEXAS – American Society of Mechanical Engineers 15th Energy Sources Technology Conference and Exhibition

FEBRUARY 2-5, PARKSVILLE, CANADA – Canadian Coal and Coalbed Conference and Exposition

FEBRUARY 18-20, LONDON, UNITED KINGDOM – European Seminar on the Control of Emissions from the Combustion of Coal: New Technologies for Power Generation and Industrial Plant

FEBRUARY 24-27, BUDAPEST, HUNGARY – International Conference on the Clean and Efficient Use of Coal: The New Era of Low Rank Coal

MARCH 4-6, AMSTERDAM, THE NETHERLANDS – First International Conference on Carbon Dioxide Removal

MARCH 11, CALGARY, ALBERTA, CANADA – Ninth Annual Heavy Oil and Oil Sands Technical Symposium

MARCH 19-28, BEIJING, CHINA – SPE Petroleum Technology Conference and Exhibition

MARCH 24-26, NUERNBERG, GERMANY – 468th Event of the European Federation of Chemical Engineering

MARCH 24-27, BEIJING, CHINA – Fourth International Meeting of Petroleum Engineering and International Petroleum Equipment and Technology Exhibition

MARCH 25-26, WUERZBURG, GERMANY – Sixth Annual Meeting on Energy Technology

MARCH 29, SAN ANTONIO, TEXAS – NPRA International Petrochemical Conference

MARCH 29-APRIL 2, NEW ORLEANS, LOUISIANA – American Institute of Chemical Engineers Spring Meeting

APRIL 7-9, DORTMUND, GERMANY – International Conference on Next Generation Technologies for Efficient End Uses and Fuel Switching

APRIL 13-15, CHICAGO, ILLINOIS – 54th American Power Conference

APRIL 20-23, PRAGUE, CZECHOSLOVAKIA – Energy and Environment: Transitions in Eastern Europe

APRIL 21-22, GOLDEN, COLORADO – 25th Oil Shale Symposium

APRIL 21-24, TULSA, OKLAHOMA – Eighth Symposium on Enhanced Oil Recovery


APRIL 28-MAY 1, CLEARWATER, FLORIDA – 17th International Conference on Coal Utilization and Slurry Technologies

MAY 4-7, CLEARWATER, FLORIDA – Third International Symposium on the Biological Processing of Coal

MAY 5-8, FUSHUN CITY, CHINA – International Symposium on Heavy Oil and Residue Upgrading and Utilization

MAY 10-14, GOLD COAST, QUEENSLAND, AUSTRALIA – 1992 Australian Coal Conference

MAY 11-15, GATLINBURG, TENNESSEE – 14th Symposium on Biotechnology for Fuels and Chemicals

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

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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 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

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

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

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


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


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

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

STUART PROJECT HAS DEFINITIVE CONSTRUCTION COST ESTIMATE

The Stuart Oil Shale Project in Australia is one step closer to becoming a reality. In spite of the general skepticism regarding its economic viability, plans to build Stage 1 of the Stuart project are steadily moving ahead.

Backers of the project, Central Pacific Minerals NL and Southern Pacific Petroleum NL, have announced that they have received a definitive proposal for construction. The proposal contains all of the necessary provisions required for detailed discussions with potential investors to proceed.

The proposal followed two independently conducted studies by internationally accepted engineering groups to undertake verification of the project’s design, operability and costs. (See the Pace Synthetic Fuels Report, June 1991, page 2-6.) The project now moves to the next phase which involves discussions with potential investors.

The demonstration plant (Stage 1) will process 6,000 tons of shale per day to produce 4,400 barrels of oil per day. Following a year of operation, the project will proceed to Stage 2 where 25,000 tons of shale per day will be processed to produce 14,200 barrels of syncrude per day.

The companies’ formal application to convert part of the Exploration Permit at the Stuart project to a Mining Lease was filed in July and is proceeding on schedule. This involves the necessary Queensland Government approval for Stage 1 of the project.

The Australian Government’s decision earlier this year to continue the excise tax exemption on motor fuels derived from oil shale until 2005 is expected to enhance the companies’ financial negotiations.

NORTHLAKE INDUSTRIES DEMONSTRATES SHALE EXTRACTION PROCESS

In November, Northlake Industries played host to United States Bureau of Land Management personnel, and business representatives from Australia, Taiwan and Alabama who saw a demonstration of oil extraction from oil shale.

Northlake’s HDR extractor is said to be capable of extracting synthetic crude oil from oil shale, tar sand and coal. Engineering data gained from ongoing tests will be used in designing commercial production units.

Northlake is proposing to develop a commercial oil shale operation at the White River Oil Shale facility in southeastern Uintah County, Utah. The company has a use permit for the facility and has put up $125,000 to extend the availability of the White River site until next June.

Yields from a demonstration, using ore from the White River Oil Shale Mine, represent a 25 percent hydrocarbon recovery or 66 gallons (1.5 barrels) per ton of oil shale, according to company spokesmen. This is said to indicate a cost of under $8 per barrel extraction cost.

Northlake officers have proposed a 1,000 barrel per day commercial unit to be in production by July 1992. Current plans call for a 100,000 barrel per day production facility to be online by mid-1995, company officials report.

The cost of the commercial plant has been estimated at $100 million.

###
PARAHO ANNOUNCES LOSS FOR YEAR

The New Paraho Corporation of Lakewood, Colorado has reported a net loss of $500,000 for fiscal year 1990-1991, as compared to a net loss of $650,000 the previous year. The company reported revenues of $516,000 for the year, but said that the ongoing test strip program and additional asphalt research resulted in the reported loss.

New Paraho has continued research and development efforts on their shale oil modified asphalt product, SOMAT. The company reports that initial evaluations of road test strips constructed in 1989 in the Rocky Mountain region indicate that SOMAT does extend road life. This summer New Paraho, working together with Marathon Oil Company, constructed three more SOMAT road strips in Texas and Michigan to test the product in different climates.
BLM DEVELOPING RESOURCE MANAGEMENT PLAN FOR WHITE RIVER AREA

The Craig (Colorado) District of the Bureau of Land Management (BLM) is in the process of developing a comprehensive Resource Management Plan (RMP) for the White River Resource Area. The RMP will govern public land management in that area for the next 15 to 20 years. The White River Resource Area encompasses nearly 1.5 million acres of public land located in Northwest Colorado.

Under the requirements of the National Environmental Policy Act and the Federal Land Policy and Management Act, BLM must develop a reasonable range of alternatives for the management of resources within the area. These alternative management plans are then to be analyzed as to the effects potential management decisions would have upon the human and natural environments.

BLM recently outlined three alternative plans for resource management in the White River Resource Area. These alternatives are subject to public comment prior to drafting the RMP. The three alternatives are:

- Alternative A: Continuation of existing management
- Alternative B: Use, occupancy and development
- Alternative C: Emphasize natural values while providing for use of public resources

The critical resource decisions regarding oil shale development are the same under all three proposed scenarios, which means that oil shale management will continue under existing management criteria no matter which of the three alternatives is selected as the preferred alternative.

The existing management criteria call for oil shale leasing and development to be in accord with the decisions made in the Piceance Basin RMP. Lease offerings would be based on demand and the progress and success of existing oil shale projects.

Oil shale/multi-mineral leasing and development could not exceed critical environmental and socioeconomic carrying capacity. Leasing and development in both underground and open pit operations would be allowed.

The multi-mineral zone would be reserved from commercial leasing pending the availability of proven technology for improved recovery rates. In addition, no oil shale leasing would be allowed in the Piceance Dome.

All potential oil shale activities would also be subject to mitigative measures to minimize the environmental and socioeconomic impacts.

MTCI WINS SBIR GRANT FOR OIL SHALE RETORTING

Manufacturing and Technology Conversion International, Inc. (MTCI) of Columbia, Maryland has been awarded a $49,993 grant from the United States Department of Energy under Phase I of its 1991 Small Business Innovation Research (SBIR) program. The grant is for an advanced oil shale retorting technology. Of the 1,401 grant applications received in response to the 1991 solicitation, a total of 173 Phase I projects were selected.

The project abstract says that syncrude obtained by retorting oil shale represents a potential source of fuel and chemical feedstock. The extent of total United States resources with greater than 15 gallons of syncrude per ton of oil shale is estimated to be 2.5 trillion barrels. The state-of-the-art oil shale retorting technology is not economic because of a number of factors, including the lack of a viable above-ground retorting process.

Laboratory-scale research on surface conversion indicates that significant improvements in retort design and efficiency are possible. The projected technology uses a compact, indirectly heated fluidized bed system to provide high heat and mass transfer rates in a well-controlled, low temperature, (<600°C) reactor environment at short residence times and high heating rates. Because this retorting process can be carried out rapidly and in a continuous mode, it provides an economic advantage by reducing the capital cost and maximizing the syncrude yield. In addition, this technology can burn raw oil shale, retorted oil shale, and retort gases in a pulsed-tube-assisted fluidized bed, thereby providing for total utilization of the shale and enhancement of the overall process economics.

The Phase I work is directed toward establishing the feasibility of retorting oil shale in a compact, indirectly heated fluidized bed and the ability of the pulsed-tube combustor to burn oil shale, retorted oil shale, and retort off-gas efficiently.

Anticipated Results

The results of successful completion of Phases I, II, and III will be a demonstration of the technology and an acceleration of the economic utilization of the large United States oil...
shale reserves to produce syncrude, which can compete with petroleum in the marketplace.

###
ECONOMICS

PARAHO PROJECTS 30 PERCENT RETURN ON SHALE OIL ASPHALT

The most recent figures from New Paraho Corporation, based in Lakewood, Colorado, show that the company expects a rate of return of around 30 percent on their shale oil modified asphalt, called SOMAT.

A paper by L.A. Lukens of New Paraho discusses the economic feasibility of producing SOMAT on a commercial scale. Lukens’ paper was presented at the 1991 Eastern Oil Shale Symposium held in Lexington, Kentucky in November.

The economic feasibility of producing shale oil modified asphalt depends on the cost associated with the production of SOMAT in comparison to the price that SOMAT can be expected to command in the marketplace. To gain acceptance in the marketplace, SOMAT must demonstrate significant “life cycle cost” benefits.

As reported previously, laboratory and field test results have shown that roads built with SOMAT should provide extensions to serviceable road life, and associated reductions in road maintenance costs. (See the Pace Synthetic Fuels Report, September 1991, page 2-8.)

Paraho has adopted a target price of $100 per barrel for SOM, the “shale oil modifier” that is blended with a conventional asphalt binder to produce SOMAT. This SOM price would result in a 10 to 15 percent increase in the as-laid cost for asphalt mix produced from SOMAT.

Paraho believes that a price of $100 per barrel for SOM is reasonable, given the life cycle cost benefits that SOMAT will provide to the consumer. This price assumption is supported by a study funded by the United States Department of Energy. This study, which was performed by J.E. Sinor Consultants Inc., determined that, if roads are built or rehabilitated on a least life cycle cost basis, the value of the portion of shale oil marketed as an asphalt modifier (i.e., SOM) would be worth $100 per barrel if use of the resulting material (i.e., SOMAT) resulted in at least a 10 percent increase in pavement life. Based on the test results to date, there is every reason to believe that SOMAT will effect at least a 10 percent improvement in pavement life, says Lukens.

The economic feasibility study was based on a facility designed to produce 2,700 barrels of SOM per day from 3,380 barrels of crude shale oil per day. As a byproduct, the plant would also produce 680 barrels of light oil per day, which would be marketed as a refinery feedstock.

Three different inflation and product pricing scenarios were analyzed, as follows:

Case 1: Assumes constant 1990 dollars for both costs (i.e., capital and operating costs) and product prices; that is, zero percent inflation for the life of the project.

Case 2: Assumes 5 percent inflation as applied to both costs and product prices, starting in year 1 and continuing for the life of the project.

Case 3: Assumes 2.5 percent inflation as applied to both costs and product prices, starting in year 1 and continuing for the life of the project, plus 2.5 percent real growth in product prices until the price of light oil reaches $31 per barrel, which occurs in year 7 of the project.

A comparison of the economic benefits associated with each of these three cases is presented in Table 1, on the next page.

With regard to economic risks, the major factors affecting the profitability of the project are the accuracy of the capital and operating cost estimates and the validity of the product pricing assumptions. Paraho believes the accuracy of these estimates to be within ±25 percent and, therefore, of sufficient quality to support valid economic assessments of the project.

An assessment of the sensitivity of the project to variations in the major economic assumptions can be measured by the discounted cash flow return on investment (DCFROI).

Figure 1 (on the next page) shows the cumulative effect of these variations on the DCFROI for both the worst and best case scenarios for all three cases analyzed. The worst case scenario assumes that the base case estimates for capital and operating and maintenance (O&M) costs are exceeded by 25 percent and that total revenues are reduced by 25 percent. The best case scenario, on the other hand, assumes that the base case estimates for capital and O&M costs are reduced by 25 percent, while total revenues are increased by 25 percent.

Paraho believes that the remaining risk factor—market risk—represents the area of greatest concern with regard to the economic success or failure of the project. This concern relates to Paraho’s ability to achieve the level of initial market penetration required to fully utilize the production capacity of the plant.

Initially, the plant would produce 1,700 barrels per day of SOM, increasing production eventually to 2,700 barrels per day. An SOM production and sales rate of 1,700 barrels per day would require a market penetration of approximately 3 percent of the projected 1994 United States demand for asphalt. The required market penetration rate increases to...
approximately 5 percent of this projected demand for an
SOM production and sales rate of 2,700 barrels per day.

Paraho says that its analysis shows that the commercial
production of shale oil modified asphalt is economically vi-
able over a reasonable range of economic uncertainty and,
accordingly, has a respectable profit-making potential.

**USE OF SPENT SHALE IN CEMENT MANUFACTURE
OFFERS ECONOMIC BENEFITS**

Operations at the Lafarge Corporation cement plant suggest
that using spent shale in cement production can have
economic benefits for both the oil producer and the cement
manufacturer.

A paper discussing the use of Devonian oil shales in the
production of portland cement was authored by
C.W. Schultz of the University of Alabama, et al., and
presented at the 1991 Eastern Oil Shale Symposium held in
Lexington, Kentucky in November.

The paper says that one unavoidable consequence of produc-
ing oil from the Eastern (Devonian) oil shales is the produc-
tion of large quantities of solid wastes. A modest sized oil
shale operation producing 10,000 barrels per day by conven-
tional retorting of a 13 gallon per ton shale would produce
28,200 tons per day of spent shale.

Disposal of spent shale in an environmentally acceptable
manner represents a substantial cost burden which must be
included in the price of the product oil. Thus, an economicend use for spent shale would improve the economics of
shale oil production.

One economic use of spent shale is in the production of
portland cement. The Lafarge Corporation currently uses
raw Antrim shale in the production of portland cement in
their Alpena, Michigan plant.

The Lafarge cement plant is the largest cement plant in
North America. The plant produces 2.0 million tons of
clinker and 2.2 million tons of finished cement each year.
The plant is located on Lake Huron adjacent to the lime-
stone quarry which provides its primary raw material.

The second major plant raw material is Antrim shale. Some
0.7 million tons of shale is quarried each year from an out-
crop located approximately 12 miles west of the plant. After
primary crushing the shale is hauled by rail to the plant site.
Operations at the plant are presented in flowsheet form in Figure 1. The coarse crushed stone and shale are further crushed to 3/8 inch, dried and blended into the raw mill. The raw stone and shale are ground to approximately 200 mesh and further mixed in the homogenizing silos.

Cement Production

Portland cement is not a simple chemical compound but rather a complex mixture of compounds and glassy phases. The raw material source of lime is primarily high purity limestone. Silica and alumina can be obtained from quartz and bauxite respectively. Aluminum silicates, however, are preferred, hence, clays, shales and slates are often used. The iron content is often obtained from iron ores.

The raw materials are blended, ground and fed to the firing kiln as a slurry (wet process) or as a fine powder (dry process). In the firing kiln where the material is heated to about 2,700°F, the following reactions occur sequentially:

- Evaporation of free moisture
- Liberation of bound water
- Decomposition of carbonates
- Reaction of lime with silica and alumina
- Fusion

The end result of these reactions is the formation of cement clinker. The balance among the compounds and glassy phases in cement clinker determine the end use of the cement. The composition is controlled in the blending prior to raw material grinding.
Use of Spent Shale in Cement

The authors point out that there may be an exploitable synergism between cement production and the production of oil from Devonian shales.

The cement industry, while large, is highly dispersed. Nationwide the clinker capacity is slightly greater than 90 million tons per year. Of that total some 15 million tons are located in the states of Alabama, Tennessee, Kentucky, Indiana, Ohio, and Michigan. Using industry average figures, 15 million tons of clinker capacity would require approximately 25.5 million tons of raw material, of which, shales or clays would amount to around 4.6 million tons. This represents the maximum potential market for oil shale waste products, i.e. spent shale.

Because this market is currently being satisfied by various sources, a more realistic market estimate might assume a market penetration of 10 to 25 percent or a real market of 0.45 to 1.15 million tons.

Quality control is critical to the cement industry. Therefore raw materials must be of consistent composition. The authors say that oil shales meet this criterion. Spent shales offer a further advantage over new shales in that they are dry, which would obviate the need for drying prior to the raw grinding operation (see Figure 1). This would marginally reduce the energy consumption in the clinkering operation.

The residual fuel value of spent shale may be a further incentive for its use in cement making. At the Lafarge plant it is generally conceded that the use of Antrim shale reduces their total energy consumption. The extent to which the calorific value of the shale is fully utilized however, or whether it represents "idle" BTU values is uncertain.

Almost universally, cement is made from locally available materials. Plant siting is normally on the basis of the availability of high-calcium limestone, the primary raw material. Under these conditions the maximum value of a spent shale to the cement producer would be equal to the avoided cost of quarrying raw shale—in the range of $3.00 to $5.00 per ton.

Spent shale has no economic value to the oil producer. To the contrary, the disposal of spent shale is an economic burden on the production of oil. Therefore a minimum benefit to the oil producer would be the avoided cost of disposal—in the range of $3.00 to $5.00 per ton.

These two effects, the value to the consumer and the avoided cost of disposal, are additive. Thus, the range of potential benefit to the oil shale operation would be $6.00 to $10.00 per ton.

The authors note that the economic potential represented by the use of spent shale in cement making can only be realized where a mineable shale exists in close proximity to the cement plant.

The authors conclude that the potential market for spent shale is small and highly localized. However, within those limitations the economic opportunity is real, and in individual cases could be significant.

###
AMOCO PATENTS SHALE OIL SYNCRUDE DEDUSTING PROCESS

United States Patent Number 4,994,175, issued to J.T. Hargreaves and J.L. Taylor, and assigned to Amoco Corporation, is titled "Syncrude Dedusting Extraction."

Background of the Invention

This invention relates generally to synthetic fuels, and more particularly, to a process for producing and dedusting oil derived from oil shale, tar sands, and other solid carbon-containing materials.

Typically, synthetic oils are produced by one of a variety of techniques including in situ, modified in situ and aboveground retorting processes or by solvent extraction. Consequently, these synthetic oils typically contain finely divided inorganic solids (dust). The removal of such solids from the oil (dedusting) greatly facilitates the transportation, refining and use of these oils.

Generally, decrepitation of oil shale accompanies the retorting process as retorting results in the decomposition of a large portion of the kerogen content of the shale, leaving behind the fine-grain inorganics of the sedimentary shale. Consequently, substantial quantities of shale dust particles become entrained in the shale oil.

Shale dust ranges in size from less than 1 micron to 1,000 microns and is entrained and carried away with the effluent product stream. Generally, because shale dust has such small dimensions, much of it cannot be removed to commercially acceptable levels with conventional dedusting equipment, such as cyclones, centrifuges or filters.

The retorting, carbonization or gasification of coal, peat and lignite and the retorting or extraction of tar sands, gilsonite, and oil-containing diatomaceous earth create similar dust problems.

After retorting, the effluent product stream of liberated hydrocarbons and entrained dust is withdrawn from the retort through overhead lines and subsequently conveyed to a separator, such as a single or multiple-stage distillation column, quench tower, scrubbing cooler or condenser, where it can be separated into fractions of light gases, light oils, middle oils and heavy oils with the bottom, heavy oil fraction containing essentially all of the dust. Typically, as much as 65 percent by weight of the bottom, heavy oil fraction may consist of dust.

It is very desirable to upgrade the bottom, heavy oil into a more marketable light oil, but because the heavy oil fraction is laden with dust it is very viscous and cannot easily be piped through transport lines. Dust-laden heavy oil plugs up hydrotreaters and catalytic crackers, abrades valves, heat exchangers, outlet orifices, pumps and distillation towers, builds up insulative layers on heat exchange surfaces reducing their efficiency and fouls up other equipment. Furthermore, dusty heavy oil erodes turbine blades and creates emission problems. Moreover, dusty heavy oil generally cannot be refined with conventional equipment.

Over the years various processes and equipment have been suggested to decrease the dust concentration in the heavy oil fraction and/or upgrade the heavy oil into more marketable light oils and medium oils. Such prior art dedusting processes and equipment have included the use of cyclones, electrostatic precipitators, pebble beds, scrubbers, filters, electric treaters, spiral tubes, ebullated bed catalytic hydrotreaters, desalters, autoclave settling zones, sedimentation, gravity settling, percolation, hydrocloning, magnetic separation, electrical precipitation, stripping and binding, as well as the use of diluents, solvents and chemical additives before centrifuging.

In addition, solvent dedusting processes wherein a dusty shale oil stream is mixed with a solvent or multi-component solvent and solids settle out of the stream have found only limited success as the rate of solids settling and cost of solvent recovery have restricted the use of these processes.

Summary of the Invention

According to the patent, the retort effluent product stream of hydrocarbons is partially dedusted in a gas-solid separation device, such as a cyclone, before being fed to a separator such as a fractionator, a scrubber or a quench tower, where it is separated into one or more fractions of normal liquid oil. For reasons of economy and dedusting efficiency, it is preferred to separate a significant portion of the dust in the bottom fraction of heavy oil. Dust is efficiently concentrated in the heavy oil fraction through distillation.

The dust-laden oil is then efficiently dedusted by dissolving the dust-laden oil fraction in a non-polar solvent comprising at least one alkane containing from 4 to 7 carbon atoms and thereby forming aggregates comprising a substantial portion of the dust. The dust-laden oil mixture can then be gravitationally separated into a substantially dedusted stream and a dust-enriched stream which contains a substantial portion of the aggregates formed during dissolution and aggregate formation. These aggregates provide acceptable settling and sludge compression rates during the separation. The dissolution and gravitational separation steps are conducted at a temperature and pressure greater than 150°F and greater than ambient pressure.
Referring to Figure 1, crushed and sized raw oil shale is fed into an aboveground surface retort. Spent (combusted) oil shale, cracking catalysts, mixtures thereof or other solid heat carrier material is fed through a heat carrier line into the retort to mix with, heat and retort the raw oil shale.

During retorting, hydrocarbons and steam are liberated from the raw oil shale as gas, vapor, mist or liquid droplets and most likely a mixture thereof along with entrained particulates of oil shale (dust) ranging in size from less than 1 micron to 1,000 microns. An effluent product stream of hydrocarbons and steam liberated during retorting is withdrawn from the retort through an overhead product line and passed to one or more internal or external gas-solid separating devices, such as a cyclone. The gas-solid separating device partially dedusts the effluent product stream, with shale dust removed from the product stream being discharged through a dust outlet line from the gas-solid separating device. The partially dedusted stream exits the cyclone and is transported to one or more quench towers, scrubbers or fractionators.

In the fractionators the partially dedusted effluent product stream is separated into fractions of light hydrocarbon gases, steam, light shale oil, middle shale oil, and heavy shale oil. Typically, heavy shale oil has an initial boiling point between about 650°F and 850°F and an end point, which includes the heaviest material in the oil, of up to about 1,100°F.

The bottom heavy shale oil fraction is a slurry of dust-laden heavy shale oil that contains about 15 to 45 percent of the effluent product stream.

The dusty heavy shale oil in the bottom separator line then is fed to the top of an extraction column. To obtain superior dispersion of the dust and a high degree of oil extraction, the
dusty heavy shale oil is mixed with a recycle stream containing shale oil and solvent by means of a static mixer.

A solvent is fed near the bottom stage of the column. This solvent serves to extract oil from the dusty, heavy shale oil dispersion being treated in the column by dissolving the feed, e.g., the dust-laden shale oil, and forming dust material aggregates. The dissolved dust-laden synthetic oil is then gravitationally separated into a dedusted oil stream leaving the top of the column and a dust-enriched sludge stream leaving the bottom of the column.

Preferably, the solvent will be a hydrocarbon solvent with an average molecular weight of about 56 to 100, and will contain few alicyclic (naphthenic), heteroatomic or aromatic compounds. Typically, the solvent will include at least one alkane containing from 4 to 7 carbon atoms, with such an alkane being a predominate portion of the solvent.

The temperature in the column will be less than the critical point of the solvent, but will generally be greater than about 150°F and the atmospheric boiling point of the solvent, preferably no more than about 350°F. The column will be maintained at a pressure greater than the atmospheric boiling point of the solvent. In this range of temperatures, pressures and a solvent-to-feed ratio greater than 1.0, it is possible to obtain dust aggregate settling rates of about 20 to 50 feet per hour. Such settling rates assure sufficient dust agglomerate residence time to allow the benefits of countercurrent flow between the descending agglomerates and the ascending solvent to be fully realized, so that increased oil extraction from the fines agglomerates is obtained.

For settling rates much above 100 feet per hour, the settling is so rapid that effective multi-stage separation of the oil from the dust cannot be obtained in conventional countercurrent extraction columns. For settling rates below 10 feet per hour, the inventory of solvent required necessitates the use of countercurrent contactors with dimensions so large as to be impractical.

Very high settling rates for the dust, in excess of 100 feet per hour, are obtainable by dedusting at or near the critical temperature of the solvent. In contrast, dedusting at temperatures below the atmospheric boiling point of a hydrocarbon solvent generally results in settling rates of only a few feet per hour. This relationship is illustrated in Figure 2. As shown in the figure, it has been discovered that the settling rate begins to increase rapidly above the atmospheric boiling point of the solvent but well below the solvent's critical point. It has been determined that the break-point temperature, e.g., the temperature at which a rapid increase in settling rate begins, is characteristic of the shale oil and not the solvent used.

**FIGURE 2**

**SETTLING RATES OF DUSTY SHALE OIL IN n-HEXANE**

<table>
<thead>
<tr>
<th>Temperature (°C non-linear)</th>
<th>Setting Rate (cm/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>277</td>
<td>80</td>
</tr>
<tr>
<td>182</td>
<td>60</td>
</tr>
<tr>
<td>144</td>
<td>44</td>
</tr>
<tr>
<td>112</td>
<td>34</td>
</tr>
<tr>
<td>84</td>
<td>12</td>
</tr>
<tr>
<td>60</td>
<td>0</td>
</tr>
</tbody>
</table>

The results of this effort are reported in a paper by A. Vego, J.L. Stehn and S.D. Carter of the Center for Applied Energy Research (CAER) at the University of Kentucky. Their paper was presented at the 1991 Eastern Oil Shale Symposium held in Lexington, Kentucky in November. The CAER has been involved with research on oil shale retorting for the past 10 years.

The cold flow model of the retort was built to verify flow rates and solid recycle rates at the 50-pound-per-hour scale. Test runs were performed using three different particle size distributions to determine the capabilities of the system and then make possible design changes to meet specifications.

The Kenton II retort includes four dense phase fluidized beds, which splits the unit into four different zones:
The pyrolysis, gasification, and cooling zones are aligned vertically and share a common fluidizing gas. Figure 1 is a diagram of the Kentort II cold flow model. The fourth bed, which represents the combustion zone, is aligned in parallel.
and the fluidizing gas is supplied separately. The main body of the test unit is constructed of transparent acrylic tubes.

The pyrolysis and combustion zones have an inside diameter of 6 inches, while the gasification and cooling zones have an 8-inch inside diameter. The total height of the unit is about 20 feet. The different zones are separated by the gas distributors which are sandwiched between flanges.

Standpipes control the bed heights. The heights of the pipes above the distributors are roughly equivalent to the minimum fluidized bed height, as follows:

- Pyrolysis: 12 inches
- Gasification: 30 inches
- Combustion: 12 inches

The standpipes, with their corresponding diplegs, penetrate through the gas distributors of the pyrolysis, gasification and combustion zones. These pipes are the passageway for the flow of solids, by force of gravity, from the upper to the lower sections of the unit. The exit port in the cooling zone also acts as a standpipe and thereby controls the bed height in the cooling zone.

The Kenton II, which uses the solids as the main heat transfer medium, has two recirculation loops:

- Gasification–pyrolysis zone
- Gasification–combustion zone

Oversized steel pipes are attached to the walls of the unit to provide inlet and exit ports for the solid recirculation systems. The solids are recirculated among the gasification and the pyrolysis zones at a rate of 200 pounds per hour. The recirculation rate among the gasification and combustion zones is 500 pounds per hour.

The solids are transported in a pneumatic conveying system which consists of aerated J-valves with corresponding lift pipes, as shown in Figure 2. The aerated J-valves are attached to the standpipes extending from the gasification zone (Figure 1).

Solids enter the unit from the top of the pyrolysis zone, flow down the standpipe to the gasification zone and are then transported up to the combustion zone. They go from the combustor back to the gasifier, are lifted back up to the pyrolysis zone and flow again down the standpipe to the gasification zone. From there, they travel down the standpipe to the cooling zone and then out the exit port.

The cold flow model was tested with three different particle size distributions:

- Fine grained, 20 x 60 mesh, previously retorted oil shale
- Coarse grained, 8 x 20 mesh, raw oil shale
- A 50/50 blend of the fine and coarse solids

The authors report that the cold flow model worked flawlessly using the three different particle size distributions. The best flow and fluidization behavior was experienced for fluidizing gas velocities between 2.5 and 5 feet per second.

Both recirculation loops were demonstrated to transport solids at the rates of 200 and 500 pounds per hour with a comfortable margin. All bed heights remained constant and the operation of the unit was shown to be very stable.

The design data obtained from the cold flow model will assist in the design and fabrication of the 50-pound-per-hour reactor.

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SYNTHETIC FUELS REPORT, DECEMBER 1991

2-13
CREATION OF LOW PERMEABILITY LAYERS COULD RETARD LEACHING FROM SHALE PILES

A commercial shale oil operation will produce huge quantities of spent oil shale and must be aware of the environmental considerations related to the disposal this solid waste including:

- Potential effects on the quality of surface and ground waters
- Potential adverse impacts on air from particulate and gas emissions
- Slope stability
- Erosion
- Worker health and safety
- Aesthetics

A paper by D.B. McWhorter focuses on controlling the potential degradation of groundwater quality through the creation of low permeability layers within a pile of spent shale. McWhorter, a professor at Colorado State University, presented his paper at the 1991 Eastern Oil Shale Symposium held in Lexington, Kentucky in November.

Long-term measures to eliminate the erosion of disposed shale are accomplished through the use of top soil, subsoils, and other available, naturally occurring materials, as permanent cover over the disposed shale.

Protection of the disposed shale from erosion is assured so long as cover material remains in place. Establishment of an enduring vegetative growth in the cover material is a key consideration in this regard.

Experiments have shown that 60 to 90 centimeters of soil is adequate to provide for good vegetative cover. However, both upward and downward movement of salts and trace elements in the shale and soil layers occurs. Upward movement occurs by capillary conduction due to the large suctions created as the root zone dries. The upward movement of salts and trace elements can be prevented by a layer of coarse material placed between the disposed shale and the soil layer. This is known as a capillary barrier.

Ground Water Quality

Numerous studies have shown that waters that pass through retorted oil shale become degraded in quality as the result of leaching of soluble substances. It is clear that minimization of leachate from disposed shale is necessary to protect the quality of ground waters that may exist beneath disposal sites, says McWhorter.

Leaching occurs from the drainage of water emplaced with the solids and from excess water infiltration. It is anticipated that water will be added to the solid waste for cooling and dust control. Also, process waste water may be co-disposed with the solids. Any quantity of these waters in excess of that which can be retained by physical and chemical processes will eventually drain from the embankment. Net infiltration will slowly penetrate the embankment and eventually become leachate also.

Combusted oil shales undergo cementitious reactions upon being wetted by water. According to the paper, such reactions are capable of immobilizing most of the waters emplaced with the solids and can cause permeability to be reduced.

Saturated Hydraulic Conductivity

Seven sets of duplicate samples were prepared and cured to determine the influence of water content during curing on hydraulic conductivity at saturation. Four samples were allowed to take on water by absorption from air, achieving a water content of 1.5 percent (by weight) or less during the 90-day curing period. The remaining three samples were wetted to 10, 15 and 20 percent by weight and cured for 90 days.

All samples were then measured for saturated hydraulic conductivity. The samples that had cured at 1.5 percent water content exhibited a 3 orders-of-magnitude permeability reduction over a 218-day test period.

Samples that were cured for 90 days at 10, 15, and 20 percent water contents exhibited about the same initial hydraulic conductivity as those that had been cured at 1.5 percent. Thereafter, however, the 10, 15 and 20 percent samples exhibited only a very modest decline of hydraulic conductivity over the 218-day test period, in contrast to the reduction by a factor of 1,000 observed in the other samples.

This difference in behavior, says McWhorter, is attributed to an armoring effect that is believed to have occurred in the samples cured at 10, 15, and 20 percent. These water contents were sufficient to cause some hydration on particle surfaces, but were insufficient to permit complete hydration. The products of hydration coating the particle surfaces acted to armor the particles and prevent further hydration when the materials were saturated for the hydraulic conductivity tests. At the same time, the partial hydration that occurred during curing was insufficient to significantly reduce hydraulic conductivity.
The samples cured at 1.5 percent or less did not experience the armoring effect and underwent full hydration during the saturated hydraulic conductivity tests. Several studies have shown that about 85 percent of the pore space must be filled with water during curing if full reduction in hydraulic conductivity is to be achieved.

**Immobilization of Water by Cementitious Reactions**

The observed 3 order-of-magnitude reduction in hydraulic conductivity suggests that an increasingly larger fraction of the water-filled pore space becomes incapable of contributing to water flow as curing proceeds.

The results of one study show that 90 percent of emplaced waters, regardless of the saturation, will be immobilized within 20 days. Therefore, an estimation of the quantity of drainable water can be made by assuming that waters remaining mobile subsequent to hydration are the only waters available for drainage.

All or a portion of the mobile waters existing subsequent to hydration will be retained in the embankment by capillarity. In a sample where 90 percent of the emplaced water was immobilized by hydration, the capacity to retain mobile water by capillarity was estimated to exceed the volume of mobile water by a factor of five.

**Creation of Low Permeability Layers**

According to McWhorter, it is clear that the armoring effect will prevent a full reduction of hydraulic conductivity if curing takes place at a saturation below some critical value. It is likely that the bulk of the disposal pile will be emplaced with water contents in the range of 5 to 20 percent by dry weight. Thus, the desirable effects of hydration on hydraulic conductivity are not likely to be realized in the bulk of the pile.

However, low permeability layers can be created by purposely creating saturated or near saturated conditions at strategic locations (e.g., layers near the bottom and top of the embankment). To prevent armoring, the saturated or near-saturated conditions must be created before the shale is exposed to saturations less than the critical value for any significant time.

**Assessment of Pile Hydrology**

The presence of one or more low permeability layers within a pile of spent shale is expected to influence the rate of water movement in the pile. Specifically, a low permeability layer located immediately below a layer of top soil is expected to significantly decrease the quantity of infiltrating waters passing into the interior of the pile. A low permeability layer would function to impede downward percolation from the root zone during wet periods, thus making more water available for evapotranspiration during subsequent periods of water deficiency.

The paper reports that a computerized simulation for a 20-year period shows that a layer of low permeability located immediately below a top-soil layer functions to hold up waters that would otherwise drain from the root zone into the interior of the pile. Waters thus prevented from rapid drainage are subsequently consumed by evapotranspiration processes. The importance of the low permeability layer in minimizing deep percolation diminishes as the top-soil depth increases.

###
WATER

UNOCAL FILES FOR WATER RIGHTS

Union Oil Company of California (Unocal) has filed an application with the clerk of Water Division No. 5 in Colorado to make a conditional water right partially absolute.

Unocal's pumping pipeline provides water from the Colorado River to be used for industrial, retorting, mining, refining and other uses in its Parachute Creek Shale Oil Project. Unocal currently owns the rights to 118.5 cubic feet per second of Colorado River water. Of this amount the right to 2.1 cubic feet per second is absolute, while the right to the remaining 116.4 cubic feet per second is conditional.

Unocal's application requests a decree from the Garfield County District Court making the company's right to an additional 3.83 cubic feet per second of Colorado River water absolute. If the request is granted, Unocal's absolute water right will amount to 5.93 cubic feet per second, with the right to 112.57 cubic feet per second remaining conditional.

Unocal's original conditional water rights were appropriated in 1949. The absolute right to 2.1 cubic feet per second of Colorado River water was decreed in October 1988.

#####
MORATORIUM PUT ON PATENTING OF OIL SHALE LANDS

A 1 year moratorium has been placed on patenting oil shale lands in Colorado, Utah and Wyoming. Under an 1872 mining law, private companies can mine for gold, silver and other minerals on federal land, obtaining title to the land for as little as $2.50 per acre.

This procedure has come under fire from environmentalists and others who say the $2.50 per acre price is too low. The moratorium will temporarily halt any further sales of oil shale lands while Congress and the United States Department of the Interior continue negotiations to resolve the issue.

The patenting process was severely criticized when claim holders in Northwest Colorado patented claims for $2.50 per acre, spending about $35,000 to acquire ownership of 11,000 acres. They then sold their rights to the land to Shell Oil Company for $37 million.

Opponents of the moratorium say it will put a stop to exploration and development, eventually leading to the destruction of the mining industry.

Several members of Congress plan to introduce bills during the moratorium that would change the system and resolve the issue.

###

PROPOSAL MADE TO LEASE NAVAL OIL SHALE RESERVE FOR GAS DEVELOPMENT

Colorado Congressman B.N. Campbell is proposing that the Naval Oil Shale Reserve, located between Parachute, Rifle and the Piceance Basin in northwestern Colorado, be opened up to natural gas development.

Campbell recently introduced a bill in a House of Representatives subcommittee which would allow the United States Bureau of Land Management (BLM) to begin leasing operations on the 55,000 acre reserve for natural gas development. The reserve is currently managed by the United States Department of Energy, which is planning to allow 111 privately-contracted wells to be drilled.

Under Campbell's bill, the land would be open for competitive bidding among private companies, with half of the gas royalties and bidding fees returned to state and local governments to be used to mitigate the effects of drilling activities.

The reserve was set aside for the Navy in the early part of this century. The management change would allow for more public involvement and could lead to more natural gas production, along with the attendant tax and job benefits.

###

NATEC RESOURCES PRODUCING NAHCOLITE IN THE PICEANCE BASIN

NaTec Resources Inc. of Houston, Texas has begun production at "the world's only nahcolite mining and processing operation," which is located in Colorado's Piceance Basin. Nahcolite, a naturally occurring sodium bicarbonate, is being produced by in situ solution mining.

NaTec is marketing the nahcolite as part of its proprietary system for injecting dry sodium bicarbonate into the stacks of coal burning power plants to reduce emissions of sulfur dioxide, and nitrogen oxides. The company holds federal leases to some 8,200 acres which are estimated to contain more than 85 million tons of nahcolite. The Wolf Ridge mine is operated by NaTec Minerals Inc., a wholly owned subsidiary based in Rifle.

The Wolf Ridge facility is currently able to produce 125,000 tons of refined nahcolite per year. However, as NaTec develops new markets for the process and the product, production can be stepped up very quickly.

Using directional drilling equipment and techniques, a vertical injection well was bored to a depth of 1,900 feet, where it reached the nahcolite bed. At that point, horizontal drilling commenced, boring approximately 1,000 feet through the mineral zone. The vertical section of the injection well is fully cased, but the horizontal portion is not cased to facilitate solution contact with the nahcolite. A vertical recovery well was then drilled and cased to the nahcolite bed, turned to the horizontal and joined with the horizontal injection borehole. (See Figure 1 on the next page.)

Barren liquor is heated and pumped down the 1,900-foot injection well to a 25-foot thick bed of 80 percent pure nahcolite. The injection solution dissolves the nahcolite and the pregnant solution is pumped to the surface through the recovery well. The solution is then cooled to crystallize the sodium bicarbonate. The crystals are precipitated from the cooled liquor, filtered and then dried, granulated and stored, ready for shipment.

During each surface cooling period, approximately 50 percent of the sodium bicarbonate contained in the solution is recovered. The solution containing the unrecovered
mineral is then added to barren liquor, heated to about 200 degrees, and returned to the mining cavity for another load.

NaTec has secured a contract to supply Wisconsin Electric Power Company (WEPCO) with up to 24,000 tons of nahcolite over a 3-year period. The utility will use the product for flue gas desulfurization in Units 1 and 4 at its Port Washington power plant. WEPCO has an option to extend the contract annually for up to 5 additional years.

The contract to supply WEPCO with dry sodium bicarbonate was received after a successful demonstration of its injection system at one of the utility’s generating plants.

The test, according to WEPCO, accomplished the goal of reducing SO\textsubscript{2} emissions by 20 to 25 percent. In addition, the NaTec injection system has the advantages of low capital cost and minimum plant outage while being installed.

A technical paper on the process, "Injection of Dry Sodium Bicarbonate to Trim Sulphur Dioxide Emissions," was authored by T. Coughlin and P. Schumacher, both of WEPCO, and D. Andrew and R. Hooper of NaTec.

According to the authors, the demonstration developed the technical information required by WEPCO to assess the potential use of sodium bicarbonate dry sorbent technology for reducing SO\textsubscript{2} emissions. The demonstration spanned approximately 3 weeks, during which time 120 tons of dry sorbent were injected for approximately 200 hours. The demonstration goal of 20 to 35 percent SO\textsubscript{2} removal, while maintaining electrostatic precipitation (ESP) opacity and emission compliance, was achieved. In addition, 70 percent SO\textsubscript{2} removal was maintained for more than 6 hours, reaching a maximum hourly average of 74 percent at top sorbent feeder speed.

The report says, "ESP mass particulate tests showed that during baseline 20 percent SO\textsubscript{2} removal and 35 percent removal periods, the average ESP efficiency increased from 98.38 percent during baseline (coal only) to 99.17 percent and 98.84 percent during 20 percent SO\textsubscript{2} removal and 35 percent removal, respectively. Outlet particulate emissions during treatment were actually lower than baseline."

Operation of the NaTec system also produces a valuable byproduct that can be recovered from stack gases. NaTec says simple filter systems and evaporative cooling crystal-
izers may be combined to recover marketable anhydrous sodium sulfate that is 99.5 percent pure.

To date, the Colorado operation has hired 22 full-time employees, with more expected as production increases.

The project began a little more than a year ago with a $20 million capital expenditure to bring the facility on line. This was accomplished almost 4 months ahead of schedule and under budget.

The expected life of the mine is 25 years and during that time it is expected to generate substantial economic benefits for the area.

###
OIL SHALE PUBLICATIONS/PATENTS

RECENT PUBLICATIONS

The following papers were presented at the 1991 Eastern Oil Shale Symposium held November 13-15 in Lexington, Kentucky:

Sharrer, W.L., "The Positive Environmental Experience at Unocal's Commercial Oil Shale Project"

McWhorter, D.B., "Disposal of Retorted Oil Shale—Status of Our Understanding of Environmental Effects"

Mensinger, M.C., et al., "Environmental Data from Laboratory and Bench-Scale Pressurized Fluidized-Bed Hydroretorting of Eastern Oil Shales"

Hopkins, T., et al., "Changes in the Physical Characteristics of Retorted Eastern Oil Shale at the Hope Creek Field Site"


Rubel, A.M., et al., "Characteristics of Processed Shales Affecting Oil Yield Loss to Coke"

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Rue, D.M., "Correlations Describing Carbon Conversion from Pressurized Fluidized-Bed Hydroretorting of Six Eastern Oil Shales"

Aldis, D.F., "Attrition and Abrasion Models for Oil Shale Process Modeling"

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Bunger, J.W., et al., "A Fundamental Molecular Concept for Separation of Shale Oil Into Chemically Distinct Fractions"

Piper, E.M., "Status of the Petrosix Oil Shale Project"

Savrda, C.E., "Bioturbated Beds in Devonian Black Shales: Anatomy, Implications, and Potential Use in Basin Studies"


Chou, C.L., "Geochemistry of Black Shales in the Illinois Basin: A Review of Recent Literature"

Freeman, D.H., et al., "Porphyrin Structure Indices of Woodford and Monterey Shale Extracts"

Ettenson, F.R., "Controls on the Origin of the Devonian-Mississippian Oil and Gas Shales, East-Central United States"

Kepferle, R.C., "The Contribution of Geological Mapping to the Understanding of the Devonian and Mississippian Shales in Kentucky—A Summary"

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Misra, M., "Selective Flocculation of Kerogen with Hydrophobic Mycobacterium Phlei"

Lamont, W.E., et al., "The Use of Antrim Shale in the Production of Portland Cement"

Schultz, C.W., et al., "Cost Optimization in Stirred Ball Mill Grinding"

Mehta, R.K., et al., "Removal of Heavy Metal Ions from Oil Shale Process Water by Ferrite Process"
Yerushaimi, J., "The Commercial Use of Oil Shale in Israel—An Update"

Dung, N.V., et al., "Processing Oil Shales with Heavy Oil Recycle"

Ekinci, E., et al., "Effect of Lignite Addition and Steam on the Pyrolysis of Goynuk Oil Shale"


Bekri, O., "Oil Shale Activities in Morocco"

Dyni, J.R., et al., "Shale Oil Resources of the Mahogany Zone in Eastern Uinta Basin, Utah"

Mahboub, K., et al., "Feasibility of the Kentort II Eastern Shale Oil for Paving Applications"

Love, G.D., et al., "Release of Biomarker Alkanes from Oil Shales and Kerogens During Pyrolysis and Low-Severity Hydrogenation"

Duewer, T.I., et al., "Raw Shale Dissolution as an Aid in Determining Oil Shale Mineralogy"

Mason, G.M., "Intermediate Decomposition of Pyrite During Oil Shale Processing"

The following paper was presented at the American Chemical Society meeting held in New York City, New York in August:


The following article appeared in Energy & Fuels for September/October 1991:

Mushrush, G.W., et al., "Chemical Basis of Instability of Shale-Derived Middle Distillate Fuels: A Model Study of the Interactive Effects Between 2,5-Dimethylpyrrole and 3-Methylindole with Sulfonic and Carboxylic Acids"

**OIL SHALE - PATENTS**

"Method for In Situ Recovery of Energy Raw Material by the Introduction of a Water/Oxygen Slurry," Leonard M. Anderson - Inventor, United States Patent Number 5,027,896, July 2, 1991. The present invention relates to methods of recovering energy materials, such as oil, shale oil or hydrocarbon gas, by providing limited combustion of these energy materials within an underground energy material reservoir and, consequently, thinning and mobilizing the energy materials such that their recovery is increased. The methods involve the injection into a borehole of a water/oxygen slurry which releases oxygen gas as it flows into the reservoir and recovering at a later time following in situ combustion and/or reaction, an improved energy material yield from said borehole or adjacent borehole.

"Kerogen Agglomeration Process for Oil Shale Beneficiation," Terry L. Marker, Bernard Y.C. So - Inventors, Amoco Corporation, United States Patent Number 5,000,389, March 19, 1991. In a kerogen agglomeration process, a substantial amount of the oil shale is comminuted to a top size greater than about 0.4 to 8 inches prior to kerogen agglomeration. Kerogen agglomeration includes comminuting the oil shale in the presence of an added organic liquid and water to form kerogen-rich agglomerates and mineral-rich particles.
STATUS OF OIL SHALE PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since September 1991)

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 co-combustants 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 dictate.

During 1991, Chevron and Conoco have been jointly negotiating 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 both its Clear Creek and Parachute Creek properties.

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, a 196-mile pipeline to Lisbon, Utah, of minor land exchanges 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 up to $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 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 $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 September 1991)

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 envisages 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)

Esperance Minerals and Greenvale Mining are planning to produce 200,000 tons per year of "asphaltine" for bitumen from the Alpha 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.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since September 1991)

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 – Union of Soviet Socialist Republics (S-80)

Two oil shale-fueled power plants with an annual output of 1,600 megawatts each are in operation in the Estonia district of the USSR. These were the first of their kind to be put into operation.

About 95 percent of USSR's oil shale output comes from Estonia and Leningrad districts. 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. 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.

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 5.5% 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.

The final results showed a required sales price 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.
The majority of Baltic oil shale (kukersite) found in Estonia and the Leningrad district in the Soviet Union is used for power generation. However, over 4 million tons are retorted to produce shale oil and gas. The Kiviter process, continuous operating vertical retorts with crosscurrent 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 generator of this type was constructed at Kohtla-Jarve, Estonian SSR, USSR, and placed in operation in 1981. The new retort employs the concept of crosscurrent 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 meters.

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 Kohtla-Jarve. Alongside these units, a new battery of four 1,500 TPD retorts, with a new circular chamber design, is planned. Oil yield of 85% of Fischer Assay is expected. Due to tightened regulations for environmental protection, the terms of the new battery commissioning have been shifted to 1994-1995.

Oil from kukersite has a high content of oxygen compounds, mostly 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 by-product in the gas generators has a hydrogen sulfide content of 8 to 10 grams per cubic meters. 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.

Shale ash is used in making cement and building blocks.

A 50 megawatt power plant burning oil shale fines in 3 fluidized bed boilers has been planned. 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 an Environmental Impact Statement for the project in 1986.

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 Timahdit, Tangier, and Tarfaya from which the name T3 for the Moroccan oil shale retorting process was derived.
COMMERCIAL PROJECTS (Continued)

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 faces constraints of low oil prices and the relatively low grade of oil shale.

Construction of a pilot plant at Timahdit 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 Timahdit was conducted by Morrison-Knudsen.

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.

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
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

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 two 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 demo plant

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

In 1920 Unocal began acquiring oil shale properties in the Parnache 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 scale oil 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.

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 breakeven 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. Production ended June 1, 1991 and the project was laid up for an indefinite period.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

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, 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:

| Operations Time, hrs | 126,400 |
| Oil Produced, Bbl    | 3,360,000 |
| Processed Oil Shale, tons | 7,070,000 |
| Sulfur Produced, tons | 568,130 |
| High BTU Gas, tons   | 121,600 |

A 36-foot inside diameter retort, called the industrial module, is being constructed. Completion of the project was put on hold in 1990, and then resumed later that year. Total investment when complete is to be $11 million when the plant becomes operational. The annual operating cost was 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.

Construction of the unit has been completed. Startup was scheduled for December 1991.

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

| Shale Oil | 3,870 Bbl |
| Processed Shale | 7,800 tons |
| LPG       | 50 tons   |
| High BTU Gas | 132 tons  |
| Sulfur    | 98 tons   |

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
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

RAMEX OIL SHALE GASIFICATION PROCESS—Ramex Synfuels International, Inc. and Greenway Corporation (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 BTU. 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?

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.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

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 million 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.

Project Cost: US$2.65 billion total estimated

STUART OIL SHALE PROJECT – Southern Pacific Petroleum NL and Central Pacific Minerals NL (S-10)

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.

Engineering is underway to firm up the project definition for a semicommercial demonstration plant. 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.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since September 1991)

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.

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 tonnes per day will produce 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 A$90 million for the first stage demonstration plant, 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$919 million over a 10-year period. The exemption is guaranteed until the year 2005. 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).

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.

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

Project Cost: For commercial demonstration module A$90 million

UTT - 3000 RETORTING PROCESS — Union of Soviet Socialist Republics (S-230)

The UTT-3000 process, otherwise known as the Galoter retort, is a rotary kiln type retort which can accept oil shale fines. Processing of the Baltic shales in UTT-3000 retorts makes it possible to build units of large scale, to process shale particle sizes of 22 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 UTT-3000 units built at the Estonian GRES with a productivity of 3,000 tons 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 capacity.

A redesign of particular parts and reconstruction 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 UTT-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 UTT-3000.

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

LO VGNIPII (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.

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.

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SYNTHETIC FUELS REPORT, DECEMBER 1991
COMMERCIAL PROJECTS (Continued)

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 barrels in situ extending over an area of 32 square kilometers within 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.

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 as it enters 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 will be studied at this scale by adding a delayed-fall combustor and fluid-bed mixer and replacing the rotary feeders with air actuated valves, suitable for scaleup. In April 1991, the first full system run on the 4 tonne per day pilot plant was completed. LLNL plans to continue to operate the facility and continue conceptual design of the 100 tonne per day pilot-scale test facility. LLNL is seeking industrial sponsors for its current operations and for the future 100 tonne per day project.

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.

LLNL is in the process of forming a consortium of companies in support of this research. Each company will contribute $100,000 per year over the next 3 years. LLNL expects to sign contracts in 1991 with five industrial partners which will form a Project Guidance Committee.
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.

The cost of carrying out the initial market development phase of the commercial development plan was approximately $2.5 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-30 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 further 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.

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.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

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
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## STATUS OF OIL SHALE PROJECTS

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OSLO WINDING DOWN

The six partners in the proposed OSLO oil sands project in northern Alberta, Canada are in the process of winding down their operations. The OSLO (Other Six Leases Operation) partners, headed by Esso Resources Canada Ltd., will close their offices in Ottawa, Ontario when work on the engineering phase of the project is finished.

Full-time employees were down to 43 this fall from 140 last winter. When the final work on technical design and environmental assessment is complete, the offices will be closed.

Canada’s National Energy Board says the start of construction for the C$4.5 billion project is not likely before the year 2000. Other sources say construction will not begin before 2005.

After 2 years of study, the OSLO consortium has decided it can go no further without government support.

Last year the Canadian Government withdrew its offer of C$750 million in cash and another C$1 billion in loan guarantees. All government financial support past the engineering phase of the project was withdrawn.

In December, Canadian Prime Minister Mulroney promised to take another look at providing federal aid.

The OSLO oil sands plant, originally scheduled to start production in 1996, is designed to produce 77,000 barrels of synthetic crude oil per day.

The OSLO partners have been working to reduce operating costs to the $10 per barrel range in order to improve the economics of the project. An analysis by the National Energy Board (NEB) says the project would require stable oil prices of US$27 per barrel to be economic. Forecasters expect to see a slow increase in world oil prices from the current range of $18 to $22 per barrel.

The NEB report says that oil from Canada’s Arctic Region would be cheaper to bring into production than the OSLO project. Oil prices of $24 to $27 per barrel would be sufficient to cover production costs for Arctic oil which is anticipated to be brought onstream in 2004.

In addition to Esso Resources, the other OSLO partners are Canadian Occidental Petroleum Ltd., Gulf Canada Resources Ltd., Petro-Canada, PanCanadian Petroleum Ltd. and the Alberta provincial government.

BIPROVINCIAL UPGRADER REQUIRES ADDITIONAL FUNDS

Husky Oil Ltd. and the governments of Canada, Alberta and Saskatchewan will provide up to $175 million in additional funding to cover construction cost overruns for the Lloydminster heavy oil upgrader. The original budget for the project was $1.27 billion, but increased labor and equipment costs have made additional funding necessary.

The upgrader is expected to become fully operational in late 1992. Husky Oil, which owns about 27 percent of the project, is anxious to complete construction in order to take advantage of the price spread between heavy and light oil in North America. When the project was conceived, the spread was in the range of $7 to $11 per barrel. Recently, however, the spread has been much wider, hovering around $14 per barrel.

The upgrader, which straddles the Alberta/Saskatchewan border, will process heavy crude oil and produce 46,000 barrels of synthetic light crude oil per day when operating at capacity.

Under the partnership agreement signed in 1988, the Canadian federal government owns 31.67 percent of the upgrader, the Alberta Government owns 24.17 percent, the Saskatchewan Government owns 17.5 percent, and Husky Oil owns the remainder.

While the demand for oil is expected to increase substantially over the coming 4 or 5 years, it is not clear how long the margin between heavy and light crude will remain high. The current wide spread in prices makes the project very economically attractive, but many forecasters expect that margin to begin to shrink.

SUNCOR REPORTS EARNINGS INCREASE, RECORD OIL SANDS PRODUCTION

Suncor’s Oil Sands Group reported earnings of $43 million for the first 9 months of 1991, compared with $21 million for the same period in 1990. The company says the increase was due to record synthetic crude oil production, but was partially offset by lower crude prices.

Earnings for the third quarter of 1991 were $10 million, compared with $20 million in the third quarter of 1990. The decline was caused mainly by lower synthetic crude oil prices, but was mitigated, in part, by higher synthetic crude production.
The Oil Sands Group recorded its highest 9-month synthetic crude production level, averaging 61,900 barrels per day. One reason the Group was able to maintain this high level of production was that there were no major maintenance shut-downs during the period. Cash operating costs averaged about $15 per barrel for the first three quarters of the year.

Recently, Suncor received an Alberta Environment Control Order for sending odorous material to the tailings ponds at the oil sands plant. Subsequently, the Group installed additional measuring and sampling equipment and upgraded its operating procedures.

###

**OIL SANDS PRODUCTION FIGURES UPDATED**

Synthetic crude oil production at the Suncor plant has remained at high levels in 1991, even though production in July was down slightly. Figure 1 outlines the plant's synthetic crude production for 1990 and the first 8 months of 1991.

Statistics published by the Canadian Energy Resources Conservation Board (ERCB) show that Suncor's production in July dropped off slightly to 245,664 cubic meters, or more than 1.5 million barrels of syncrude. Total production of synthetic oil at Suncor for the first 8 months of the year is 2,385,476 cubic meters, roughly equivalent to 15 million barrels.

While July represented the lowest monthly production for Suncor, the opposite was true for the Syncrude plant. As shown in Figure 2 (on the next page), synthetic crude oil production at the Syncrude plant reached the highest level for the year to date in July at 941,789 cubic meters, or nearly 6 million barrels of oil.

In the first 8 months of 1991, the Syncrude plant has produced 6,239,438 cubic meters of synthetic crude oil, the equivalent of 39.2 million barrels.
FIGURE 2

SYNCRUDE SYNTHETIC CRUDE OIL PRODUCTION, 1990–1991

DATA SOURCE: ERCB

SYNTHETIC FUELS REPORT, DECEMBER 1991
In its annual report to the Securities and Exchange Commission, Solv-Ex Corporation states that it is seeking funding to develop the Bitumount Lease in Alberta, Canada. The company acquired the Bitumount Lease, Alberta Bituminous Sands Lease No. 5, in January 1988 from Can-Amera Oil Sands, Inc.

The company is seeking funding from joint venture partners or venture capital to participate in the development of the oil sands lease. Solv-Ex also approached the governments of Canada for financial assistance to develop the Canadian oil sands reserves and the proposals are currently under review.

The company has satisfied the cash payments for the Bitumount Lease, but is still required to process 2,000 tons of material from the lease through the company's pilot plant by December 31, 1992. Once production commences on the lease, Solv-Ex will be required to pay Can-Amera at a rate of C$0.07 per barrel up to an amount not to exceed US$11,475,000.

The Process

Solv-Ex has developed a bitumen extraction process that combines continuous solvent extraction and hot water treatment of oil sands without air flotation. Crushed oil sands are removed by screening. The bitumen content of the resulting oil sand-hot water slurry is then extracted into a water immiscible solvent of low density to form a solvent-bitumen solution, or extract phase, a middle water phase, and a lower spent-sand phase.

A specially selected naphtha derived from refined oil sand bitumen is used as the solvent. Each phase is further processed to produce bitumen, recovered solvent, clean hot water, and clean spent-sand. The remaining dry fines can be further processed to separate other potentially valuable minerals.

The bitumen extraction process has been tested in the company's pilot plant using oil sands samples from Santa Rosa, New Mexico; Sunnyside and PR Spring, Utah; and Athabasca, Alberta, Canada.

Solv-Ex has been granted patents for its oil extraction process by the United States, Canada and several other countries.

In September 1991, Solv-Ex was granted a patent for extracting minerals from clean tailings of the oil sands after the oil extraction or from mineral bodies of similar nature. The company revised its material feed system for its oil extraction process to include a hydrotransport system for the oil sands. This approach has made it feasible to separate the sand from the oil up front in the process and to reclaim the sand in an acceptable clean and dry state.

Solv-Ex plans to market the technologies and license the rights to use the processes to adjacent leaseholders in the Athabasca region.

The Product

The Bitumount Lease contains potentially significant amounts of bitumen from tar sands, titanium, alumina, iron, gold and silver. Solv-Ex anticipates extracting the bitumen, using its patented extraction process, and either selling the bitumen or upgrading it into a light synthetic crude oil. Alternative uses of bitumen would include sale to the asphalt market or use as a coker feedstock.

The patented bitumen extraction process yields clean tailings from which potentially significant mineral values can be extracted. The minerals to be extracted are anticipated to be upgraded and sold in the market place.

The Pilot Plant

The company's 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 20 process runs of low (6 percent bitumen), average (8 to 10 percent bitumen), and high (12 to 14 percent bitumen) grade oil sands through the pilot plant. The test material was procured from a pit centrally located in the oil sands deposit on which the Bitumount Lease is located. The test results are given in Table 1.

<table>
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<tr>
<th>Percentage of Bitumen Material by Weight</th>
<th>Average Percentage of Bitumen Recovered</th>
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<td>6.0</td>
<td>75</td>
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<tr>
<td>9.0</td>
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<td>12.0</td>
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SYNTHETIC FUELS REPORT, DECEMBER 1991
Lease Evaluation Unit

The company plans to construct a modular Lease Evaluation Unit in Alberta, Canada to accomplish the required processing under the Bitumount Lease and evaluate the value of the oil, metals and minerals in the oil sands. The proposed Lease Evaluation Unit will incorporate the hydrotransport system where the process for extracting the oil from the oil sands will begin.

The design for the proposed Lease Evaluation Unit is based upon data acquired from the company's pilot plant. However, additional engineering is needed before construction can begin. Once the unit is operational, the company will begin to evaluate the oil, mineral and metals from selected leases and develop a tailings pond sludge cleanup program. This information will be used to secure engineering data for a commercial extraction plant (i.e., 30,000 barrels per day). The total estimated cost for this program, including the construction of the proposed Lease Evaluation Unit, is $12 million.

Bitumount Project

Mineral core samples from the Bitumount Lease and other leases in the Athabascan region were tested and evaluated by Mountain States Research and Development International, Inc., Vail, Arizona. Based upon the results of these tests and studies prepared by the Canadian Government and other companies, the company prepared a preliminary feasibility study for a project which would involve the construction of a commercial-scale oil sands and minerals processing plant, the "Bitumount Project."

The Bitumount Project is planned to be developed in multiple stages. The first phase will include a drilling program to secure adequate oil sand samples for testing and analysis. The samples will be processed through the company's proposed Lease Evaluation Unit to determine the oil, mineral and metals values on the Bitumount Lease. The cost for this phase is estimated to be $2 to $4 million and is not included in the cost for the proposed Lease Evaluation Unit.

NOVA TO SELL HUSKY

NOVA Corporation of Calgary, Alberta, Canada announced that it has entered into an agreement to dispose of all of its interests in Husky Oil Ltd. for a total of CS$325 million. The purchasers of NOVA's 43 percent equity interest in Husky for CS$250 million will be companies associated with L. Ka-shing of Hong Kong. As part of the transaction, Husky will redeem its preferred shares held by NOVA for CS$75 million.

The transaction is subject to regulatory and other approvals, including approval from Investment Canada.

The cash proceeds of CS$325 million will be used to reduce non-cost-of-service debt. NOVA said its decision to sell its investment in Husky is due to the need to continue to focus its available resources on its gas transmission business. NOVA's pipeline system is undergoing a major expansion to meet increased demand for natural gas transmission service.

The transaction between NOVA and the other principal shareholders of Husky is part of a financial restructuring of Husky pursuant to which NOVA will withdraw as a shareholder. Because of its capital programs and level of indebtedness, Husky requires substantial additional equity investment from its shareholders, which NOVA is not prepared to make.

As a result of the disposition, for the third quarter of 1991 NOVA will record an after-tax loss from discontinued operations of approximately CS$265 million. The investment in Husky had been accounted for as an asset held for sale.

The price received by NOVA for its investment in Husky reflects current values in the Canadian oil and gas industry. These values have deteriorated throughout the year due to continuing low oil and gas prices. NOVA could obtain additional cash proceeds if oil and gas prices rise significantly higher than current levels within the next 2 years.

NOVA reported consolidated net income from continuing operations in the third quarter of 1991 of CS$7 million, compared with CS$22 million in 1990 and a net loss of CS$6 million in the second quarter of 1991.

Net income from continuing operations for the 9 months ended September 30, 1991 was CS$39 million, compared with CS$136 million for the same period in 1990.

NOVA's net loss, including continuing and discontinued operations, for the first 9 months of 1991 was CS$250 million, compared with net income of CS$134 million for the same period in 1990.

When Husky Oil announced that its principal shareholders had reached an agreement which would effect a recapitalization of the company and allow it to meet its substantial financial commitments, Husky chief executive officer, A. Price stated, "Investigating various recapitalization alternatives and discussions with shareholders has been a preoccupation of senior management involved in responding to financial and other commitments of Husky to its employees and in the communities in which Husky operates. This financial support and vote of confidence in Husky is both welcome and timely."

SYNTHETIC FUELS REPORT, DECEMBER 1991
IMPERIAL CONSIDERING HEAVY OIL UPGRADER

Imperial Oil Ltd. is said to be looking into the possibility of building a heavy oil upgrader in Alberta, Canada.

It has been reported that the company has a crew of 10 or 15 people conducting a low level study on the various available technologies, project economics and siting possibilities. A company spokesman says that no firm decisions will be made about such a potential project until mid-1992.

Imperial is considering building their own upgrader as an alternative to the OSLO oil sands project, the construction of which has been delayed for an indefinite period. Imperial would use the upgrader to process the heavy oil from its Cold Lake heavy oil deposits.

PETRO-CANADA SELLS PART OF SYNCRUDE INTEREST TO MITSUBISHI

Petro-Canada has announced that, as part of its asset rationalization program, it has signed a letter of intent with Mitsubishi Oil Company, Ltd. to sell a 5 percent interest in the Syncrude oil sands project. The purchase price for the interest will be C$132.5 million.

In addition, should cash flows exceed a defined level, Petro-Canada and Mitsubishi would share equally in the excess over a 10-year period, with Petro-Canada's share not to exceed C$50 million. Upon completion of the sale, Petro-Canada will continue to own 12 percent of the Syncrude project. The sale price approximately represents Petro-Canada's current net book value of the interest sold.

Petro-Canada Resources president N. McIntyre said, "We are pleased to have reached this milestone. The sale is part of our ongoing program to restructure our asset base in order to achieve higher levels of profitability and reduce debt."

Before the C$95 million after-tax writedown related to the company's interest in the Syncrude project, Petro-Canada's net earnings were C$10 million on revenues of C$1.2 billion for the third quarter of 1991.

After the Syncrude writedown, the overall net loss for the quarter was C$85 million, equivalent to a loss of C$0.40 per share.

Net earnings for the same period in 1990 were C$50 million on revenues of C$1.4 billion. Cash flow from operations in the third quarter of 1991 was C$105 million, down from C$179 million in the same period of 1990.

For the first 9 months, the net loss was C$234 million, compared with earnings of C$78 million in 1990. Cash flow from operations was C$206 million, down from C$399 million in 1990.

The company completed its initial public offering of common shares on July 3, 1991, raising C$523 million of new equity. Proceeds were used to reduce short-term indebtedness. After the share issue, approximately 19.5 percent of the company's shares were held by the public.

MURPHY CITES FAVORABLE HEAVY OIL RESULTS WITH HORIZONTAL DRILLING

Murphy Oil Corporation maintains a strong position in the heavy oil regions of Alberta and Saskatchewan, Canada. Heavy oil continues to be plagued by low prices, but the company considers its large reserves in this area to be a valuable company asset for the future.

In his remarks to security analysts in New York City, New York and Boston, Massachusetts, E.L. Dawkins, president of Murphy Exploration and Production Company, said that horizontal drilling techniques used in this area have been very successful. Horizontal drilling has resulted in increased economic production in Murphy's Tangleflags, Plover, and Senlac fields. He also said that Murphy is studying the use of horizontal drilling techniques in the Lindbergh field.
DOE CALLS FOR ADVANCED OIL RECOVERY PROPOSALS

The United States Department of Energy (DOE) has issued its first call for proposals for oil field demonstration projects in an attempt to keep many aging United States reservoirs in production while ushering in a new generation of more effective oil recovery technology.

Release of the "program opportunity notices" in October began an effort cited by DOE as one of the highest energy supply priorities of its National Energy Strategy. DOE projects that advanced production techniques applied to existing United States oil fields could add more than 3 million barrels per day of domestic oil production by the year 2010.

DOE's Deputy Energy Secretary, W.H. Moore, said, "In January 1990, we told industry that we would refocus our oil program to meet critical short-term, real-life needs. Now that we have done that, we are asking industry to join us in demonstrating technologies that, in many cases, can mean the difference between continued operations and premature shut-in."

"Our objective is to give operators--particularly independents--a broader menu of oil field options that can keep endangered reservoirs in production and, ultimately, maximize the amount of oil this nation can produce within its own borders," he said.

Industry has until January 15 to propose demonstration projects that meet either a "near-term" or "mid-term" objective. The "near-term" objective is to promote more widespread application of oil field technologies proven in other areas to prolong the economic life of a reservoir. The "mid-term" objective is to test more advanced approaches that can extract even greater quantities of oil from a reservoir.

DOE will share up to half of the costs of selected projects, providing as much as $40 million for the field tests. Winning projects could be chosen as early as April 1992.

To make the program more responsive to industry practices and requirements, DOE has made substantial changes in the way it plans to cooperate financially and managerially with companies chosen in the upcoming competition. Rather than assuming a direct role in specifying how selected projects will be run, DOE will primarily provide financial assistance with a minimal amount of day-to-day oversight. Industry will be given the flexibility to determine the best way to carry out the projects.

In return for this degree of project control, DOE will require a minimum of 50 percent private cost-sharing for each project. This level of cost-sharing is expected to assure that industry chooses the best field projects to submit. Originally, DOE had proposed setting no minimum level of private cost contribution for the near-term projects and 20 percent private cost-sharing for mid-term projects.

"Being in day-to-day control of a project without the government second-guessing each decision has been a major incentive for the private sector to participate in our Clean Coal Technology Demonstration Program, and industry has shown no reluctance in meeting the 50 percent cost threshold in return for that approach," Moore said. "We believe the same approach in the oil program will increase the probability of success for the participants who, of course, will derive the principal benefits, and for the nation which will reduce its reliance on external, potentially insecure suppliers."

DOE's call for proposals is the first of as many as 10 competitions that could be carried out this decade as part of the advanced oil recovery program. Each competition would involve a specific type of geologic formation. Priority would be given to those formations, or reservoir "classes," that contain large amounts of unproduced oil and also have major fields that are in danger of being abandoned as uneconomic.

For this first competition, DOE is targeting "fluvial dominated deltaic reservoirs," an oil-bearing formation known to exist in at least 11 of the most prolific oil producing states in the United States.

Up to 10 projects could be chosen to demonstrate "near-term" techniques, those that can be applied commercially within the next 5 years. Operators may already be using these techniques elsewhere to keep certain fields in production, and DOE hopes that by co-financing their demonstration across a broader geographic area, operators will gain sufficient confidence to replicate them in similar geologic formations. As much as $10 million in federal funds will be provided for these projects.

Another set of projects, as many as four, will be chosen from the "mid-term" proposals. These projects will demonstrate techniques that go beyond preventing oil field abandonments and attempt to maximize the amount of oil that ultimately can be recovered economically from a reservoir. Until now, many of these techniques have been tested only at small scales or in the laboratory. If field demonstrations prove successful, they could be in commercial use in the latter half of the 1990s. DOE has allocated up to $30 million for these projects.

In most projects, the private company will likely conduct a preliminary geologic and engineering analysis of the reservoir to determine its characteristics. If the analysis indicates
sufficient potential for additional oil recovery, the actual field demonstration will be carried out.

A key requirement of all projects will be the private company's willingness to transfer successful technology to other operators. Data from both the reservoir analyses and the field demonstrations will be made available to operators, state agencies and others in an effort to encourage widespread replication of techniques shown to be effective.

###

**TABLE 1**

**SUMMARY OF OIL SANDS ORDERS AND APPROVALS**

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<td>16 Aug 91</td>
<td>Primary recovery schemes</td>
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ERCB ISSUES ORDERS AND APPROVALS IN OIL SANDS AREAS

The recent orders and approvals in the oil sands area issued by Alberta's Energy Resources Conservation Board (ERCB) are listed in Table 1.
ENERGY POLICY AND FORECASTS

NATIONAL ENERGY BOARD PREDICTS INCREASING BITUMEN PRODUCTION


Energy Prices

The report’s outlook is for sustainable oil prices ranging from US$18 to $22 per barrel in 1991, with the range growing to US$20 to $35 in 2010. This range reflects both political and economic uncertainties associated with projecting long-term oil prices. For analytical purposes, the NEB presented a Control Case roughly in the middle of the range, growing from US$20 in 1991 to US$27 by 2010.

Energy Demand

The report’s expectations are for low energy demand growth for Canada, with end use demand growing from 7,600 petajoules in 1989 to 9,800 petajoules in 2010 in the Control Case, an increase averaging 1.2 percent per year. These projections are predicated on modest economic growth, ongoing energy efficiency improvements associated with technological change, environment-related measures considered viable given the report’s price outlook, and demand management programs.

End use fuel shares are expected to change very moderately over the projection period. Although the gas share increases slightly in the period to 2000, by 2010 the shares of electricity (22 percent) and coal (6 percent) are each about 2 percentage points higher than in 1990, and those of oil (37 percent) and gas (25 percent) are lower than in 1990.

Energy Supply

The Control Case outlook suggests that Canada’s crude oil and equivalent supply will remain relatively stable over the projection period, declining initially and then increasing to a level 16 percent higher in 2010 than in 1990. While the total supply of crude oil and equivalent is projected to change only modestly, the average quality of the crude oil and the regional distribution of supply changes considerably. Over the projection period heavy crude oil comprises an increasing proportion of the total supply and the importance of frontier supply increases, whereas supply of light crude oil from Western Canada becomes relatively less significant. Current reserves are compared to projected reserve additions by 2010 in Figure 1.

Oil price sensitivity tests indicate that the outlook for frontier, synthetic crude oil, and bitumen supply is particularly sensitive to the crude oil price projection. Many new Canadian supply sources are relatively high cost by world standards and will require real growth in prices or technological changes which reduce costs in order to become viable over the projection period.

The Control Case crude oil and equivalent supply projection is very similar to the low case of the 1988 report during the early portion of the projection period, but thereafter moves gradually toward the high case of that report. As in the 1988 report, the contribution of heavy crude oil supply, particularly bitumen, and frontier supply increases and conventional light crude oil supply from the Western Canada Sedimentary Basin declines over the projection period (Figure 2). This has implications for the crude oil transportation system and refinery configuration in Canada.
Light crude oil shipments from Western Canada to Montreal via the Sarnia-Montreal segment of the Interprovincial Pipe Line system have recently ceased. As light crude oil supply from the Western Canada Sedimentary Basin continues to decline, it will be necessary for Ontario refiners to examine their supply options, one of which would be to reverse the Sarnia-Montreal line to allow imported light crude oil to be shipped to Sarnia via Portland, Maine. NEB anticipates that over most of the projection period the growth in domestic demand for petroleum products can be met by increased utilization of existing domestic refinery capacity, together with some modest debottlenecking of refineries in conjunction with investments which will be necessary to meet more stringent environmental standards.

###

UNITAR DIRECTOR NOTES IMPORTANCE OF HEAVY OIL AND TAR SANDS

"With the improvement of recovery technologies in the years ahead, heavy crude and tar sands will appear as the unrecognized hydrocarbons for the 21st century." This remark was made in reference to the enormous resources of natural bitumen, which, in Alberta, Canada alone, amount to some 1.7 trillion barrels of which only 10 percent is estimated to be recoverable with current technologies.

In his opening address to the Fifth UNITAR International Conference on Heavy Crude and Tar Sands held in Caracas, Venezuela in August, M.D. Kingue, executive director of UNITAR, discussed the relevance of heavy crude and tar sands in view of the availability of conventional petroleum at an affordable price.

According to Kingue, the estimated identified recoverable conventional petroleum resources worldwide amount to some 1 trillion barrels, while identified recoverable resources of heavy and extra-heavy crude are estimated to be some 500 billion barrels with another 450 billion barrels of recoverable natural bitumen. These estimates, he noted, are based on current recovery technology.

Kingu says that the most compelling arguments for developing the world's heavy crude and tar sand resources are their great magnitude, their widespread occurrence, and the
availability of the technology for their development. However, there is still no reliable estimate of the volume of heavy oil and bitumen in the world. Only a few countries have made reasonably good resource estimates, accounting for approximately 3 to 4 trillion barrels. Nevertheless, he says that the size of the combined resources of heavy oil and bitumen are believed to be equal to or greater than the quantity of light conventional oil when measured on an equivalent basis.

Every day there are more and more references being made in the trade journals about the production of new heavy oil fields. In Canada, by using horizontal drilling methods, the Alberta Oil Sands Technology and Research Authority (AOSTRA) has increased the productivity of known reservoirs considerably. By the same token, production costs have decreased, making the barrel of heavy oil competitive, pricewise, with that of conventional oil.

In Indonesia, he says that Chevron Oil has successfully applied steam flooding on a gigantic scale to the Duri field heavy oil reservoir formations, and is now aiming at production of 200,000 to 300,000 barrels per day. In the North Sea, Chevron Oil and its partners are considering placing the Alba field on production, making it the first heavy oil producer in that area.

In cooperation with the United Nations Development Program (UNDP), UNITAR established the Information Centre for Heavy Crude and Tar Sands, which is funded mainly by the oil industry together with the United States Department of Energy. It was established in 1981 with its headquarters at the United Nations in New York City, New York. One of its purposes is to keep developing countries with undeveloped heavy crude and tar sands informed about advances in technology that would enable them to extract and upgrade their heavy oil and bitumen resources into marketable products, at competitive prices, in an environmentally acceptable way.

The year 1991 marks the 10th anniversary of the UNITAR/UNDP Centre for Heavy Crude and Tar Sands which has organized four of the five International Conferences on Heavy Crude and Tar Sands. The first such conference was the one which gave birth to the Centre itself.

Through these conferences, participants have been able to gather state-of-the-art technology in all of the many disciplines required to bring those resources into the marketplace. The proceedings provide a permanent record of the efforts of thousands of researchers and technologists working in this area over this 10-year period. The Centre has fostered the exchange of technologies among the commercial sector and academia, and collectively made this knowledge available to all.

"We are living at a time of profound social, economic and technological transition and a period of growing recognition of the effects of unrestrained development on the global climate and its threat to the future well-being of mankind, a subject that will be addressed at a United Nations Conference on Environment and Development to be held in Rio de Janeiro in June 1992," said Kingue. "The use of fossil fuel has been identified as one of the major sources of greenhouse gases in the atmosphere and it is our duty to see that the fossil energy we produce is used in the most effective and efficient way possible. The challenge to the heavy crude and tar sands scientists and engineers at this meeting is to bring this vast storehouse of energy into the marketplace in an environmentally acceptable manner so that we can be part of the solution and not part of the problem. This is a challenge that is commensurate with the magnitude of the resource and will require experts' ingenuity and skills to bring it about."
CLEAN COAL TECHNOLOGY MAY FIND USE IN HEAVY OIL APPLICATIONS

Some of the United States Department of Energy (DOE) research on clean coal technologies may be applicable to direct combustion of heavy and extra heavy crude oils.

According to G.J. Stosur of DOE, the utilization of heavy crudes is headed on two parallel but separate paths. The traditional path leads to heavy oil upgrading using a variety of processes. A new trend, however, is the direct utilization of the raw material as fuel for heat or power generation.

Stosur outlined the clean coal technologies that are applicable to heavy oil fuels in a paper presented at the Fifth UNITAR International Conference on Heavy Crude and Tar Sands held in Caracas, Venezuela in August.

With shortages of light, sweet crude oil supplies likely in the years ahead, projections show a slow but steady increase in the demand for heavy crude through the year 2000 (Figure 1).

Stosur argues that, "Compared to coal, nature already upgraded heavy oil to a liquid, placing it one step beyond fuels converted from coal or oil shale." Considering that both Canada and Venezuela each have more than 1 trillion barrels of heavy oil, "the world is not running out of oil; it may only be running out of the easy-to-produce light oil."

The term "clean coal technology" refers to advanced coal-based systems that offer significant potential for improved environmental and economic performance in power generation and industrial applications, as well as for other uses.

Clean coal technologies can be applied at any of three stages in the "fuel chain" or in a fourth manner that departs from the traditional method of coal burning. These stages are as follows:

- Precombustion cleaning: sulfur and other impurities in coal are removed before it reaches the boiler.
- Clean combustion: pollutants inside the combustor or boiler are removed while the coal burns.
- Post-combustion cleaning: cleaning flue gases released from coal boilers in the ductwork leading to the smokestack or in advanced versions of today's scrubbers.
- Conversion: the combustion process is bypassed altogether; coal is changed into gas or liquid that can be cleaned and subsequently used as fuel or converted into other energy products.

A list of the various technologies is shown in Figure 2 on the next page.

While any one of these four stages can be used with heavy oil, the clean combustion and the post-combustion cleaning stages are particularly applicable.

Combustion Cleaning

Fuel can be cleaned as it burns, which requires no additional sulfur or nitrogen removal equipment. During the last 20 years, two new categories of advanced technology have emerged: fluidized bed combustors and advanced (slagging) combustors.

In a fluidized bed combustor, crushed coal mixed with limestone is suspended on jets of air (fluidized). As the coal burns, sulfur is released, and limestone captures the sulfur before it can escape from the boiler. Small ash particles, or "fly ash," are carried out of the boiler and captured with dust collectors. More than 90 percent of the sulfur released from coal can be captured in this manner.

Because the tumbling motion of the coal enhances the burning process, combustion temperatures can be held to around 1,400 to 1,600°F. This is below the threshold at which nitrogen pollutants form. Thus, fluidized bed combustors can meet both SO₂ and NOₓ standards without any additional pollution control equipment.
### FIGURE 2

**CLEAN COAL AND POTENTIAL FOR DIRECT HEAVY COMBUSTION**

<table>
<thead>
<tr>
<th>Pre-combustion cleaning</th>
<th>Clean combustion</th>
<th>Post-combustion cleaning</th>
<th>Conversion</th>
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<td>Fine grinding (micronization)</td>
<td>Combusiners/Burner Types</td>
<td>In-duct Injection</td>
<td>Mild Gasification</td>
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<tr>
<td>Advanced froth flotation</td>
<td>Slagging combustors</td>
<td>Sorbent injection</td>
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<td>Heavy media cyclones</td>
<td>Limestone injection</td>
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<tr>
<td>Microfiltration</td>
<td>multi-stage burners</td>
<td>Post-Combustion Devices</td>
<td>Underground Coal Gasification</td>
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<td>Advanced drying</td>
<td>Gas reburning</td>
<td>Furnace injection w/water activation reactor</td>
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<td>Molten caustic leaching</td>
<td>Fuel Types</td>
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<td>Microbial</td>
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<td>Advanced Scrubbers/FGD</td>
<td>Coal/Oil Co-processing</td>
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<td>Gasification Combined-Cycle</td>
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<td>Regenerative scrubbers</td>
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<td>Dual alkali scrubbers</td>
<td>Gasification with Fuel Cells</td>
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<td>Electrostatic precipitators</td>
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<td>Sorbent injection/High temperature baghouse</td>
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<td>Large module forced oxidation lime scrubbers</td>
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<td>Electrode precarchger enhancement to precipitators</td>
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<td>High-temperature baghouses</td>
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**SOURCE: STOSUR**

### Post-Combustion Cleaning

Until the emergence of clean coal technologies, post-combustion cleaning had been the principal method of meeting air quality standards. Although techniques are available that remove as much as 90 percent of sulfur pollutants from the flue gases of burning coal, new methods for post-combustion cleaning offer significant improvements, says Stosur.

Advanced post-combustion $\text{SO}_2$ controls can be grouped according to where in the physical layout of the power plant they perform their sulfur-removing functions.

In-duct sorbent injection works inside the ductwork leading from the boiler to the smokestack. Sulfur absorbers (such as hydrated lime) are sprayed into the center of the duct, where 50 to 70 percent of the $\text{SO}_2$ can be removed. The reaction produces dry particles that can be collected downstream.

Advanced scrubbers place the flue gas processing facilities outside the main power plant. These devices offer advantages such as regenerating the sulfur-absorbing chemical, making the system more economical; removing both $\text{SO}_2$ and NO$_x$; producing an environmentally benign, dry waste product; or streamlining operations by reducing or eliminating the need for reheating or backup modules.

Some improvements may use an additive to boost sulfur capture. For example, adding adipic acid to the scrubbing solution may permit as much as 97 percent $\text{SO}_2$ removal, rather than the current 90 percent.

For nitrogen oxides, recent innovations make it possible to reduce NO$_x$ in flue gases leaving the coal boiler, instead of in the combustor. The most extensively developed concept is selective catalytic reduction.

### Technologies Applicable to Heavy Oil Fuels

The following is a brief description of some clean coal technologies which would most likely find application to clean burning of heavy oils.

**Sorbent Injection**

LIFAC North America with five other industrial participants will retrofit a high-sulfur coal burning plant with an ad-
vanced SO₂ emission reduction technology using LIFAC's flue gas desulfurization process. The process combines limestone sorbent injection and spray humidification technologies to reduce SO₂ emissions. The system can capture 75 to 85 percent of the sulfur pollutants from flue gas, compared to 50 to 70 percent typical of other injection systems, through a two-step process using an activation chamber added to a plant's existing ductwork.

Confined Zone Dispersion

Bechtel Corporation will demonstrate a low cost way to reduce SO₂ and NOₓ pollutants with confined zone dispersion (CZD). The CZD approach would capture pollutants inside a plant's ductwork. Although not as effective as a scrubber, the technology could allow many existing power plants to remain operating while cleaner plants are built.

CZD would use atomizers to inject a fine spray of water and limestone into the ductwork between a boiler's air heater and particulate removal equipment. The atomizers create a cone shaped confined zone of wet particles surrounded by an envelope of hot combustion gases. As the cone moves through the duct, gas inside the cone would cool and SO₂ would be absorbed by the droplets, then mix with hot gases outside the cone and dry very quickly.

Gas Suspension Absorption (GSA)

AIRPOL Inc. will demonstrate the applicability of gas suspension absorption for flue gas desulfurization utilizing high-sulfur coal. The GSA method would combine the benefits of spray dryers with the emission reduction capabilities of conventional scrubbers at 40 percent less cost than wet scrubbers. A single spray nozzle is used to inject fresh limestone slurry.

Advanced Tangentially Fired Combustion

Southern Company Services in Florida will demonstrate several NOₓ control techniques on a 180-megawatt tangentially fired utility boiler. Three techniques will be used: advanced over-fire air, the low NOₓ concentric firing system and the concentric clustered tangential firing system. Each will be evaluated separately and then in combination on a single demonstration boiler during a period of 3 years.

Wall-Fired Boiler Gas Reburning and Low-NOₓ Burner

An Energy and Environmental Research Corporation demonstration will show that the combination of gas reburning and low NOₓ burners can reduce NOₓ emissions by about 75 percent. If successful, the project will also demonstrate decreases in SO₂, particulate and CO₂ emissions using equipment that can be easily retrofitted to existing boilers. Gas reburning involves cofiring 15 to 20 percent natural gas with coal. The gas is injected into the furnace above the main coal combustion zone to produce a slightly fuel-rich zone where NOₓ produced by the coal combustion is "reburned" and reduced or converted to atmospheric nitrogen. Additional overfire air is added above this "reburning zone" to burn out the combustibles.

Conclusions

The potential for worldwide heavy oil recovery is greater than the current production levels would indicate, says Stosur. Many of the environmental concerns associated with direct utilization of heavy and extra heavy crudes can be overcome with advanced technologies now being developed and demonstrated by DOE's $5 billion clean coal program.

HORIZONTAL WELLS BECOMING VIABLE FOR HEAVY OIL AND TAR SANDS

While the majority of horizontal well applications to date are for primary recovery of light oils, a limited number of horizontal wells have also been drilled for producing heavy oil and tar sands.

A review of these heavy oil and tar sands applications was presented at the Fifth UNITAR International Conference on Heavy Crude and Tar Sands held in Caracas, Venezuela in August. The paper was authored by P.N. Mutalik and S.D. Joshi of Joshi Technologies International, Inc., Tulsa, Oklahoma.

The review indicates that, in recent years, the majority of the heavy oil field projects with horizontal wells have been in heavy oil fields in California in the United States, in heavy oil and tar sand fields in Canada and in heavy oil fields in Venezuela. The authors conclude that the use of horizontal wells in non-thermal applications for heavy oil reservoirs appears to be economically viable, while the use of steam in conjunction with horizontal wells shows mixed economic results.

Thermal Recovery Processes

The processes involving the use of horizontal wells for thermal oil recovery can be classified into three categories: cyclic steam, steam drive, and steam assisted gravity drainage. These three processes have been used in both heavy oil and bituminous reservoirs.

In cyclic steam stimulation, only one horizontal well is used, both as the injector and as the producer, with alternating injection and production cycles, and with a possible interim soak period. Steam is injected into the reservoir and left to soak in order to increase the temperature and to reduce the viscosity of the oil.
A steamflood or steam drive usually consists of a pattern-type flood. Steam, injected continuously in the injector well, not only reduces the oil viscosity but also displaces the oil (and the produced water) to the surrounding wells. In a steam drive, one can employ several combinations of horizontal wells and vertical wells as injectors and producers. This is especially important in bitumen reservoirs, which are typically developed on smaller well spacings as compared to heavy oil reservoirs. Also, bitumen reservoirs may initially require cyclic steam stimulation to enhance production rates before starting steam drive.

In the steam assisted gravity drainage process, horizontal steam injectors and oil producers are in close proximity to each other, with the injector located above the production well. A minimum pressure differential, close to the gravity head differential, is desirable between the injector and producer wells. The injected steam travels upward and the hot displaced oil as well as condensate, is collected in the bottom horizontal producer.

**Non-Thermal Applications**

Two case histories, discussed below, involve the use of horizontal wells for non-thermal applications.

**Edam West, Canada.** In December 1988, Gulf Canada drilled its first horizontal well in the Sparky heavy oil formation in West Edam Field. Of the 1,830 foot length of the horizontal section, about 1,370 feet encountered the sandstone-filled channel sands of the Sparky formation. The well was drilled to a total depth of 3,380 feet. The cost of drilling and completion for this first well was about 2.5 to 4 times that of a vertical well. Production from the horizontal well stabilized at rates greater than 300 barrels of oil per day, which is more than seven times the rate of an average vertical well in the same field.

When the well was put on production, high water and sand cuts were initially encountered. A lowering of pump speed had no influence on water cut. Later, an increase in pump speed resulted in higher total production and lower water cut. This indicated that the water production was not due to coning but was produced from localized pockets of high water saturation. Sand cut, though initially about 10 percent, later stabilized at 4 percent.

**Lake Maracaibo, Venezuela.** The first horizontal well was drilled in Venezuela by Lagoven, S.A. in an oil saturated Eocene sandstone reservoir in the Lake Maracaibo area in November 1989. The horizontal well was initially completed at a total vertical depth of 5,215 feet. At this depth, only a 25-foot thick sand was found in contrast to an expected thickness of 40 feet. Hence, the initial production rate was also lower than expected.

Based on a new geological interpretation, the fluid characteristics of the produced 19°API oil, and the bottomhole pressures, the well was recompleted. The new section showed initial production of approximately 900 barrels of oil per day on gas lift, which was more than twice the rate of offset vertical wells.

According to the paper, a long horizontal well has also been drilled in the tar sand belt in eastern Venezuela. The importance of good geology for a successful horizontal well project is clearly demonstrated by these case histories.

**Thermal Applications**

The following section discusses several case histories involving the use of horizontal wells for thermal applications.

**Tangleflags, Canada.** In the Tangleflags North area of Saskatchewan, Canada, Sceptre Resources conducted a pilot steamflood in the unconsolidated Lloydminster sand in 1987. The reservoir has a gross thickness of about 120 feet and is overlain by a 20-foot thick gas cap and underlain by a 5 to 15-foot thick bottom-water zone. The bottom-water quickly cones into vertical wells, limiting oil recovery. In this pilot steamflood project, steam was injected in a vertical well drilled to a depth of 1,475 feet and the oil was produced from a 1,300-foot-long horizontal producer, drilled about 60 feet below the vertical well injector. This process is a combination of steam drive and steam assisted gravity drainage.

By the end of 1988, production had reached about 300 barrels per day and had increased to about 600 barrels per day in the first quarter of 1989. This was more than 8 to 10 times the productivity of a non-thermal horizontal well and more than 15 times the productivity of a non-thermal vertical well.

**Cold Lake, Canada.** One of the most extensive experimentation and pilot studies for bitumen recovery has been done at Cold Lake Oil Sands in the Clearwater formation by Esso Resources Canada. The current level of bitumen production is about 90,000 barrels per day from nearly 2,000 wells. Most of this production comes through the use of the cyclic steam stimulation process.

Two horizontal well pilot projects are in operation at the site, with a third project underway to test the technical and economic feasibility of a horizontal well as an alternative or as a follow up to cyclic steam stimulation.

The first horizontal well pilot, which was drilled in 1979, had an 800-foot slotted liner located about 100 feet below the top of the Clearwater formation. The well configuration consists of a vertical well injector located directly above the horizontal well. Phase I involved continuous steam injection into and production from the same horizontal well. In Phase II A, high pressure steam was injected in the vertical well injector and the horizontal well was used as a producer. This configuration showed significant improvement in the production
The 800-foot-long horizontal well produced 50,000 cubic meters (about 315,000 barrels) of oil in about 10 years.

Fort McMurray, Alberta, Canada. Since 1985, AOSTRA (Alberta Oil Sands Technology and Research Authority) has been operating the underground test facility project northwest of Fort McMurray, Alberta, Canada. One of the test programs involved a six-well test of steam assisted gravity drainage. The well layout consisted of three pairs of horizontal wells. Each well pair consisted of a producer completed about 10 feet above the base of pay and an injector located about 15 feet above the producer. The horizontal wells were drilled on 80-foot spacing and the effective length of each pair was about 200 feet.

Midwest, United States. In the United States, a fairly large but shallow deposit of heavy oil and tar sands exists in the midwestern states. In a cyclic steam stimulation test, a 1,000-foot-long horizontal well was drilled in a 25-foot thick payzone containing 16°API gravity oil. After the first cycle, oil production was not sufficient to continue the process. The lack of oil response was probably due to inadequate steam injection, and inability to inject steam uniformly along the length of the long well.

Olinda Field, California. In the Olinda Field in California, the ultrashort radius radial system, which involves drilling of multiple radials from a single spudding location, was used in direct-drive steamflood patterns in 1985-1986. A comparison of two five-spot patterns in the same steamflood showed that the pattern with four radials on the injector produced about 50 percent more oil as compared to an identical pattern without radials. In addition to increased production, there was a sharp drop in operating costs.

**Parameters for Economic Success**

The authors say that a review of the literature indicates that several factors are important for a horizontal well heavy oil project to be an economic success. Some of the key technical parameters which govern the economic success of a horizontal well heavy oil project include reservoir geology, drilling costs, well completions, and sand control scheme. In addition, uniform steam distribution along the length of horizontal well may also play an important role.

**Geology**

For a successful horizontal well project, a good geologic description of the reservoir is very important, they say. In some instances, horizontal wells have been drilled outside of the producing formation because of a lack of geologic information or a poor estimate of formation dip. On the other hand, highly developed reservoirs with good geologic information may not have enough well spacing to drill horizontal wells. The importance of good geological control is very well illustrated by the case histories of the Edam West horizontal well and the Lagoven horizontal well.

**Drilling Costs**

The typical drilling cost for an ultra-short-radius horizontal well in the United States is about $25,000 to $30,000 per radial. The typical cost for a short-radius well at a 5,000-foot depth would be approximately $120,000 to $200,000 for a 250-foot-long horizontal well, whereas a medium-radius well at the same depth would cost about $600,000. In most instances, first well costs are higher than the second or third well costs.

**Well Completions**

Several factors must be considered before selecting a suitable completion scheme for a horizontal well, such as rock and formation type, drilling technique used, formation damage and sand control problems.

In practice, most horizontal wells are completed with liners. These liners are specialized slotted liners, where slots are oriented in a special direction or directions to obtain sand control. In some instances, wire wrapped screens are also used to enhance sand control. The other option is to either gravel pack or use pre-packed screens. Recently, it has been reported that gravel packing is feasible in horizontal wells. However, pre-packed liners can be expensive, and therefore, to minimize cost, alternate sections of pre-packed liners and solid liners have been used.

**Sand Control**

Sand production can impair productivity of horizontal wells because of the difficulty in removing sands from horizontal wellbores. A selection of liner type, perforation and wire spacing is important in sand control. In addition, particle mixing in the annulus can cause significant permeability damage.

Sand control seems to be a serious problem in some of the field projects. Theoretically, one would expect a smaller magnitude of sand control problem in a horizontal well than in a vertical well. This is because the production per unit well length is smaller in a horizontal well than that in a vertical well. This expectation has been met in some of the nonthermal horizontal wells, producing from unconsolidated heavy oil reservoirs. However, the results with steam application appear to be mixed, and especially in steam applications of horizontal wells in heavy oil reservoirs, sand control seems to be a major problem.
Uniform Distribution of Steam Along the Horizontal Well Length

Another parameter which affects choice of well completion is the steam distribution along the length of the well. Conventional injection techniques would probably result in steam of varying qualities being delivered along the length of the horizontal well. A novel design has been recently suggested which not only enables better distribution of steam but also enables sand control.

Figure 1 shows a schematic of this well design. The design provides the flexibility to circulate steam when necessary and at higher annular velocities required to fluidize and remove any sand that may have entered the horizontal well.

VCC TECHNOLOGY READY FOR COMMERCIALIZATION

The Veba-Combi-Cracking (VCC) technology has been the focal point of Veba Oel's development activities for more than a decade. After 10 years of intensive development work, the VCC process is ready for commercialization.

An update on the status of VCC technology is provided by K. Niemann of Veba Oel (Germany) in a paper presented at the Fifth UNITAR International Conference on Heavy Crude and Tar Sands held in Caracas, Venezuela in August.

The VCC Process

The VCC technology is a hydrogen addition process based on Bergius-Pier technology which was applied in Germany for coal liquefaction in the 1930s and 1940s and for upgrading of refinery residues in the 1950s and 1960s. The basic principles of the process are given in Figure 1 (on the next page), based on the installations at the Bottrop Coal Liquefaction Plant.

Heavy crude oils, refinery residues (preferably vacuum residues) asphalts or tars are slurried with a finely ground one-way additive, preheated after adding recycle gas and hydrogen and fed into the liquid phase hydrogenation reactors (LPH) where the conversion in a once-through mode of operation takes place at temperatures between 440 and 485°C and pressures between 150 and 250 bar.

The unconverted residual oil, potential solids and the additive are separated from the distillates in a hot separator (HS). The HS bottoms are fed into a vacuum tower, where distillable products are separated from the hydrogenation residue. The HS overheads are fed to a directly-connected hydrotreater (GPH reactor) which operates at the same pressure but a somewhat lower temperature than the LPH unit. This is where, by hydrotreatment on a fixed-bed catalyst, the final high-quality synthetic crude is obtained.

Primary conversion rates of up to 95 weight percent are achievable resulting in high liquid yields of > 100 volume percent. Coking of the remaining hydrogenation residue in Veba Oel's proprietary low temperature carbonization (LTC) step enables a further significant gain in volumetric liquid yields. This makes it possible to achieve an overall conversion of up to 97.5 weight percent.

Conclusion

In general, the application of horizontal wells for non-thermal heavy oil applications appears to be economically viable, whereas the use of steam in conjunction with horizontal wells shows mixed economic results.

###
Bottrop Coal Liquefaction Plant as VCC Plant

The Bottrop Coal Liquefaction Plant ("Kohleol-Anlage Bottrop") was used from 1981 through 1987 to demonstrate hard coal liquefaction in a technically relevant scale. The process was optimized to achieve liquid gains of >50 weight percent.

In 1987 the Bottrop plant was modified for the conversion of heavy residual oils using the VCC process. The plant has a capacity of 200,000 tons per year vacuum residue which is pipelined from the Ruhr Oel refinery located at Gelsenkirchen (15 kilometers distance).

The configuration of the Bottrop plant is very similar to the flow scheme in Figure 1. The vacuum residue as obtained from the refinery is mixed with the additive and then pressurized to the final pressure level.

The primary hydrocracking section consists of three LPH reactors which are installed in series. The product leaving the third LPH reactor is transferred to the hot separator where vapors and liquids/solids are separated.

The hot separator bottom product, that is, the non-converted residue together with solids and heavy distillates, becomes depressurized in steps and then vacuum distilled.

The HS top product is directly hydrotreated with conventional HT catalyst in gas phase reactors without intermediate depressurization. The heat of the GPH products is used for feed preheating. After final cooling by water coolers the liquids are separated from the gases which are mainly recycled to the process.

Conversion of Heavy Refinery Residues

In January 1988 the Bottrop Coal Liquefaction Plant was started up after modification into a VCC plant. The plant has a capacity for conversion of 24 tons per hour of vacuum residue. Since 1988, approximately 210,000 tons of vacuum bottoms have been converted into 180,000 tons of synthetic crude oil.

Figure 2 shows the product spectrum feeding Venezuelan vacuum bottoms to the plant. By using 2 percent of a coal derived additive and adding 3.5 weight percent hydrogen, the following products are gained:

- 10.4 weight percent hydrocarbon gases
- 19.3 weight percent naphtha
- 46.5 weight percent middle distillates
- 14.5 weight percent vacuum gas oil

Recycling of Waste Materials

According to the author, recycling of industrial waste materials is a must for the near future to exploit the whole potential of hydrocarbon resources. Waste materials which can be recycled via the VCC process are:

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Figure 2

**CONVERSION OF VACUUM-RESIDUE**

<table>
<thead>
<tr>
<th>Hydrogen</th>
<th>Feed</th>
<th>Product</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.5</td>
<td></td>
<td>5.2 H₂S, NH₃, H₂O</td>
</tr>
<tr>
<td>Vacuum-Residue</td>
<td>100</td>
<td>10.4 C₁-C₄-Gas</td>
</tr>
<tr>
<td>Additive</td>
<td>2.0</td>
<td>19.3 Naphtha</td>
</tr>
<tr>
<td></td>
<td></td>
<td>46.5 Middle Distillates</td>
</tr>
<tr>
<td></td>
<td></td>
<td>14.5 Heavy Gas Oil</td>
</tr>
<tr>
<td></td>
<td></td>
<td>9.6 Residue</td>
</tr>
</tbody>
</table>

**Source:** Niemann

- Used lubricant oils
- Cutting oils
- Residues from degreasing plants
- Chlorinated used solvents
- Painting sludges
- Oils from transformers (PCBs)
- Spent catalysts
- Spent activated carbons

In the Bottrop plant, wastes have been upgraded now for almost 2 years, supporting the concept on a commercial scale. Even politically sensitive materials like polychlorinated biphenyls (PCBs) are hydrocracked there; chlorine decontamination is quantitative in all cases.

**Conclusions**

Engineering work for a 3.5 million ton per year heavy oil upgrader in Alberta, Canada is under way after a VCC license was given to the OSLO partners. In parallel, Veba Oel Technologie GmbH has entered into negotiations with other potential VCC clients.

All results from the Bottrop plant and further engineering studies support the advantages of the process. The process allows recycling oils and natural bitumen, as well as recycling of industrial waste oils, including PCBs.

According to Niemann, the short-term availability of such a technology is of special value. Additionally, liquid phase hydrogenation is a breakthrough in recycle of industrial waste streams.

####
INTERNATIONAL

NIGERIA TAR SANDS MAY BE DEVELOPED

Ondo State in Nigeria and the Alberta Oil Sands Technology and Research Authority (AOSTRA) have signed a memorandum of understanding for scientific and technical cooperation related to the possible development of the Agbabu bitumen deposit in southwestern Nigeria.

The total oil in-place in Ondo State is estimated to be as high as 42 billion barrels. The total recoverable oil in the Agbabu deposit is estimated at 1,022 million barrels, based on existing technology.

Two papers describing Nigerian tar sands were presented at the Fifth UNITAR International Conference on Heavy Crude and Tar Sands held in Caracas, Venezuela in August. One paper was authored by R.D. Adelu of the Ministry of Petroleum Resources in Nigeria, et al., and the other was authored by O.S. Adegoke of Obafemi Awolowo University in Nigeria, et al.

The Nigerian tar sand belt stretches for over 120 kilometers, averaging about 5 kilometers in width. The shallow oil sands occur in two distinct stratigraphic bands with a combined average thickness of 30 meters. Mean oil saturation is 12 percent weight.

Properties of the Tar Sand Oil

Based on the results of all studies carried out to date, the physical and chemical properties of the tar sand oil can be summarized as shown in Table 1. On the basis of these properties, it has generally been concluded that the bitumen meets the specifications for "straight run grade" of bitumen commonly used on Nigerian roads.

The gross hydrocarbon composition shows higher resins and asphaltenes, and lower aromatics than Athabasca oil. This suggests that the Nigerian bitumens may be less suitable as fuel oil and petrochemical feedstock.

TABLE 1

PROPERTIES OF NIGERIAN TAR SANDS

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>API Gravity:</td>
<td>14.6° to 53°</td>
</tr>
<tr>
<td>Specific Gravity:</td>
<td>0.204 - 1.837</td>
</tr>
<tr>
<td>Penetration:</td>
<td>80 - 100</td>
</tr>
<tr>
<td>Softening Point:</td>
<td>47°C</td>
</tr>
<tr>
<td>Breaking Point (after Fraas):</td>
<td>10°C</td>
</tr>
<tr>
<td>Drip Point (after Ubbelohde):</td>
<td>58°C</td>
</tr>
</tbody>
</table>

The Nigerian bitumens have higher carbon, hydrogen and oxygen than the Athabasca bitumens, while the sulfur, nickel and vanadium values are much lower than for Athabasca bitumens. The calcium and iron content of the Nigerian bitumens are higher while the potassium, magnesium and sodium content are lower than those of Athabasca bitumen. The latter may enhance the upgrading and refining qualities of Nigerian bitumens.

Prospects for Development

With the large amount of oil in place and the acceptable physico-chemical characteristics of the oil, plans are being considered for the exploitation of the tar sands and the associated heavy oils.

Nigeria presently has a lube plant as part of the Kaduna refinery. The feedstock is the Lagomar crude imported from Venezuela. The installed capacity is 50,000 barrels per day.

Nigeria is a net importer of lubricants and other automotive fuels. The need for additional lube oil plants utilizing locally produced feedstock can thus be readily justified.

The results of a pilot plant test carried out on 50 tons of Nigerian tar sands and intensive laboratory tests carried out in Canada show that heavy oil can be extracted from the tar sands by both the hot water process (Clark) or the Lurgi/Ruhgas dry process. The latter process, developed initially for coal retorting, has not yet been commercially tested, however.

Direct production of heavy oil from tar sands by the application of enhanced oil recovery (EOR) or in situ techniques has been under pilot tests in Canada, the United States, Venezuela and other countries for several years. Because the bulk of the Nigerian tar sands dip southwards beneath thick sequences of Tertiary and Neogene formations, the thrust of the commercial development in the future could be the application of EOR techniques in these vast areas. The smaller capital outlay required could make this a more attractive alternative for Nigeria than tar sand mining and extraction.

Products and Byproducts

The prime product from the mining and extraction of the tar sands and from the in situ production is heavy and extra-heavy crude oil. The heavy oil must be upgraded to form synthetic crude oil or syncrude, a suitable feedstock for heavy oil refineries. On refining, the distillates produce a limited quantity of motor spirits, considerable amounts of diesel, fuel oil, lube oil, asphalt and pitch.
The most important of the byproducts is sulfur. The sulfur content of the Nigerian tar sand oil extract is 0.9 to 1.2 percent weight. Therefore, this would be the largest source of elemental sulfur for Nigeria. The other important byproducts include phenol, ammonia and the alloy metals nickel and vanadium.

Government Role in the Project

The Nigerian Government set up a Committee on the Implementation of the Bitumen Project (CIBP) in June 1989. This presidential committee is charged with the responsibility of developing policies and strategies for exploiting bitumen economically. The CIBP is currently holding discussions with several potential investors who have indicated interest in the commercial exploitation of the resource.

The current activity by the federal government with respect to natural bitumen production is timed to coincide with the start of a cyclical upturn in demand for petroleum and petroleum products which is projected to peak at the end of this decade.

ORIMULSION MAKING PROGRESS IN EUROPEAN MARKETS

Orimulsion was first fired in a commercial plant in Europe in July 1989 in a 500-megawatt oil-fired power station. Two years later a joint venture formed to market Orimulsion has lined up long-term contracts to deliver more than 9 million tonnes of Orimulsion per year.

Italy's ENEL alone will purchase 1 million tonnes of Orimulsion per year. Other markets include Western European countries, Eastern North America and Japan, where Orimulsion could supply 2 percent of the primary energy used to generate electricity by the year 2000, according to a report in the Oil & Gas Journal. By 2000, 50 percent of the expected output of 50 to 60 million tonnes per year will be exported to Europe.

The same company has since converted all three of its 120-megawatt units in southeast England to burn Orimulsion. Permission was given by the local regulatory authority for the plant to burn Orimulsion on a regular basis and the station has been operational since the middle of 1990. In December 1990 PowerGen carried out a 4-week trial on its oil-fired plant at Grain. This is the largest liquid fueled station in Western Europe. Following the successful completion of a trial on one of its 660-megawatt boilers, PowerGen is assessing the future role of this station.

Boiler Performance

The main properties of Orimulsion which impact on boiler performance are its water content and the ash produced. Combustion efficiency has been found to be better than with heavy fuel oil.

Furnace performance is modified by a combination of lower flame temperature and emissivity, higher specific heat and mass of combustion products and increased furnace fouling. This can be minimized by the use of sootblowers as the deposits are easily removed.

The water content of the fuel has the effect of reducing thermal efficiency by almost 2.5 percent. A further reduction in efficiency will occur due to the increase in final gas temperature, unless additional heating surface is installed. However, most of these deficiencies are amenable to correction by relatively simple and cheap modifications, says the paper.

A paper that reviews the technical and environmental aspects of the first 2 years of operation was authored by J.M. Sharkey of BP BITOR and presented at the 1991 International Joint Power Generation conference held in San Diego, California in October.

The main market for this fuel is the underutilized oil-fired power stations in Western Europe. Utilization factors there are low and for most countries are less than 20 percent.

The First Trials

The first major trial of Orimulsion in Western Europe was on a 500-megawatt unit at Ince power station in the United Kingdom in 1989. Following a successful single burner trial, the station carried out a full trial burning 40,000 tonnes over a 3-week period. The boiler is front wall fired with 32 steam atomized burners.

After the successful completion of this trial the company signed a 5-year contract for 1 million tonnes of Orimulsion per year. An electrostatic precipitator is now being built and the plant is scheduled to be on-load towards the end of 1991.

Orimulsion is an oil-in-water emulsion currently being produced from the vast natural bitumen deposits of Venezuela's Orinoco Belt. This region holds about 1,200 billion barrels of bitumen in-place, of which 267 billion barrels are recoverable with present technologies and economics.

The Venezuelan national oil company, Petroleos de Venezuela S.A. (PDVSA), formed a new subsidiary company, BITOR S.A., which in turn formed a joint venture with BP, called BP BITOR Ltd., for the marketing of Orimulsion to the power generation and industrial markets mainly in the European Economic Community (EEC) countries.

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Environmental Characteristics

Most countries require a detailed environmental assessment of the impact of changing the feedstock to a plant. To assist utilities, BP BITOR has carried out a number of detailed studies relating to the environmental impact of using Orimulsion.

One topic of concern is the handling of the ash arising from the combustion of Orimulsion. Because of the pre-atomized nature of Orimulsion, with an average particle size of less than 20 microns, combustion is very good. All of the combustion in the utility sector to date has been with steam atomized burners, where the unburned carbon in the ash has been less than 1 percent and in several cases undetectable. The results from the various trials on plants fitted with electrostatic precipitators (ESP) show that emissions of less than 50 milligrams per cubic meter can be achieved even on precipitators not specifically designed for Orimulsion. Utilities are considering a number of different ways to handle the ash. One method is to compact the material into pellets and then transport to clay lined landfill sites for disposal.

BP BITOR is working closely with a consultant to study the technical, economic and environmental implications of building a plant to extract the vanadium and nickel from the fly ash and producing a solid and liquid effluent that is environmentally acceptable.

The other area where there has been a large amount of environmental interest is in the area of marine spills. When spilled into seawater, Orimulsion immediately disperses and forms a plume of dispersed oil in the top 2 to 3 meters of water. Depending on the sea conditions, some of the bitumen may resurface as “tar balls.” In freshwater the Orimulsion disperses but because of its density it sinks and there is no surface effect.

Conversion to Orimulsion

The type and amount of changes required in an oil-fired boiler depend on the boiler type and its role. If a utility requires full power on base-load, then extra sootblowers are usually added and some changes are made to the heating surfaces to compensate for the different characteristics of Orimulsion. If a utility is not capacity constrained, then some down-rating of the unit can be allowed and a minimum cost boiler conversion carried out.

Uncontrolled particulate emissions from Orimulsion are about 250 milligrams per cubic meter. This exceeds the limits for most European countries. It has been found that electrostatic precipitators can achieve the EEC standard for a new large combustion plant of 50 milligrams per cubic meter.

Orimulsion has a sulfur content of 2.7 percent and an equivalent emission of 3.8 percent when the water is taken into account. A utility can meet local limits by either de-rating the unit or using some form of partial sulfur reduction. In Western Europe there is also a requirement to meet national sulfur bubble limits, set by the EEC.

According to Sharkey, there are a number of factors which make desulfurizing a plant burning Orimulsion attractive compared with an equivalent coal-fired plant. These include a relatively constant feedstock, a coastal location, and in the longer-term, new technologies specific to emulsions.

Orimulsion has the advantage that it comes from a single large resource that does not vary significantly in quality. Thus a flue gas desulfurization (FGD) plant designed for Orimulsion can be optimized for its quality.

In addition, most oil-fired stations are located on the coast. This allows a utility more cost effective options in the choice of FGD that also have less impact on the environment. A number of companies have technologies based on seawater washing. At a coastal power station using seawater as a cooling medium this can be an attractive option, says the paper.

The final stage in the conversion is the commissioning and operational phase. BP BITOR can provide a mobile laboratory to assist in the analytical support required during this phase. Orimulsion requires some different equipment for measuring its properties, in particular a particle size counter and viscometer. In addition, combustion expertise is available and mobile laboratories for in-stack and ambient monitoring are available.

Future Applications

In the next few years there will be increasing pressure for more efficient and cleaner electric power generation. Large-scale pilot plant work has already shown that Orimulsion can be efficiently and easily gasified. One major European utility is seriously considering the gasification of Orimulsion. As the technologies of hot gas cleanup become commercial and turbines become more efficient, it is likely that Orimulsion will play a significant role in combined cycle gasification plants. Some utilities are also considering using Orimulsion in a topping cycle to improve station efficiency and it is likely that trials will take place in the next 1 or 2 years.

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AOSTRA ANNUAL REPORT OUTLINES
INTERNATIONAL EFFORTS IN HEAVY OIL AND OIL SANDS

The 1991 Annual Report of the Alberta Oil Sands Technology and Research Authority (AOSTRA) summarizes interna-
AOOSTRA continued an active international program during 1990/1991 with the signing of five memoranda of understanding with Argentina, China (SINOPEC), Japan, Azerbaijan and Kazakhstan (two Soviet Republics). Negotiations are under way with Nigeria, Brazil, Ecuador, India, and Albania.

China

Activities between AOOSTRA and the China National Petroleum Corporation (CNPC), including its subsidiaries, have been revitalized in 1990/1991 after a 1-year period of relatively low-key relations. CNPC actively maintained its participation in AOOSTRA's University and ARC Access Programs by sending representatives to attend the Annual Technical Review Meetings and Seminars. The president of CNPC, W. Tao, also accepted Premier Getty's invitation to visit Alberta in mid-April 1991, heading an 11-person delegation.

The Second Canada-China Heavy Oil Technology Symposium, held in October 1990, was jointly organized by AOOSTRA and CNPC. The Alberta and Canadian governments provided their support to the symposium.

While in China, AOOSTRA signed a memorandum of understanding with SINOPEC International which is the international arm of the China Petrochemicals Corporation. SINOPEC is a state-owned enterprise specializing in the downstream operation of the petroleum industry in China. AOOSTRA will join SINOPEC to cosponsor an international symposium on heavy oil and residue upgrading and utilization in May 1992.

The Henan Petroleum Exploration Bureau (HPEB), under the terms of an agreement signed in 1989, sent two groups to Alberta for training. The first group, consisting of two oil field geologists, worked at the Alberta Geological Survey for 2 months and studied image analytical techniques and reservoir description and modeling. AOOSTRA recently sent one geologist to Henan to help set up an Image Analytical Laboratory. The other group, including two engineers, are receiving 6 months of on-the-job training with Syncrude Research in Edmonton, Alberta, Canada for modern heavy oil and oil sands analytical procedures and techniques.

Soviet Union

The return visit by a Soviet delegation, for the two AOOSTRA specialists who spent 3 months in the USSR in 1989, took place from April to June 1990. For the last 3 weeks of their visit, the three Soviet specialists were joined by two senior officials from their organization, ISTC "Oil Recovery." This group was in Alberta to study AOOSTRA technology, visit research and field projects, and meet with Alberta companies regarding investment opportunities in the USSR in enhanced recovery. Serious discussions also took place for the opening of a joint office in Moscow to facilitate technology transfer between the two countries.

Following the visit of a Soviet delegation to Alberta, AOOSTRA attendance at the Neftegaz 1990 oil and gas show in Moscow, and the visit by an AOOSTRA delegation to various parts of the Soviet Union, much interest was generated by the AOOSTRA Taciuk Processor (ATP) in that country. AOOSTRA has subsequently received several inquiries about sales of the unit, and are planning to send a delegation to the USSR to further discuss the matter.

During the visit by an AOOSTRA delegation to the USSR, letters of intent were signed for testing of oil sands and sludge samples using the ATP with two groups that fall under the State Committee for Science and Technology, with whom AOOSTRA has a memorandum of understanding.

A 3-week visit of a delegation from the Kazakh SSR followed the signing of a memorandum of understanding with the Research and Production Association "Dortekhnika." This group is primarily interested in using mined oil sands for road paving material. They were acquainted with in situ exploitation technology of bitumen from shallow oil sands deposits (slant well drilling, steam-assisted gravity drainage with horizontal wells), and with the ATP operation. As a result of this visit, a letter of agreement was signed for testing oil sands samples from Kazakhstan to prepare a road paving precursor directly from the feed material using the ATP.

A five-person Kazneftebitum/ISTC delegation visited Alberta for 10 days in January 1991. Their main interests were in joint venture and staff exchange possibilities, mainly in the areas of oil sands mining and in situ operations. They were also interested in the ATP, and offered to purchase two units. A statement of principles was signed before their departure, so that both parties can consider future technological exchanges.

A delegation from the Institute for Solving Problems of Deep Oil and Gas Deposits of the Academy of Sciences of the Azerbaijan SSR visited Alberta for a 2-week period. A memorandum of understanding was ratified during their visit. A letter of protocol detailing future collaboration and a preliminary technological perspective for treating oil sands using the ATP were prepared for consideration. Of all the dealings so far with the Soviet Union, this group has shown the most enthusiasm and willingness to enter into technological cooperation.

Hungary

Two colleagues from the Hungarian Hydrocarbon Institute spent about 6 months at the University of Calgary's combustion laboratories to conduct combustion tube experiments using Hungarian technology related to the Countess B pool.
The results of this international collaboration are very promising for application of in situ combustion technology to Alberta’s light and medium heavy crudes. The summary report contains a proposal for the application of the new technology at PanCanadian’s Countess pilot. A return visit of three researchers from the University of Calgary’s Combustion Group is planned to the Hungarian Hydrocarbon Institute laboratories.

The Hungarian Oil Trust has proposed to conduct up to $200,000 worth of research at the University of Calgary’s combustion laboratory. This effort, together with research work in Hungary, would form the basis for a field application in Hungary of the jointly developed AOSTRA/HHI combustion technology.

Cuba

UMATAC completed preliminary test work on Cuban oil sands (mari) samples from the Marga deposit. The results of the treatability tests, based on modified Fischer Assays and batch pyrolysis tests, indicate that the Cuban mari, a calcareous clay or intermixture of clay and particles of calcite or dolomite, has low water content, gives attractive oil yields (145 liters per ton), and is therefore amenable to treatment and production of oil by the ATP. The deposit covers an extensive area, is 200 meters thick, and lies 200 meters below the surface. Present studies center on adapting borehole mining techniques to this deposit. Permeabilities in the deposit are too low to permit in situ recovery.

Two Cuban experts arrived in early March for a 3-month training period to conduct reservoir engineering studies on their heavy oil reservoirs, Varadero and Boca de Jaruco. Both reservoirs are highly fractured carbonates containing 12 to 15°API oil at 60°C.

Trinidad

The Trinidad and Tobago Oil Company Ltd. (TRINOC) has expressed interest in the AOSTRA Taciuk Processor for potential use in exploiting the Lower Maren L’Enfer oil sands deposits in Trinidad. Steps are under way to examine the physical and chemical characteristics of these oil sands at the Alberta Research Council, and to batch test oil sands samples at the UMATAC pilot plant in Calgary to determine oil quality and oil yield predictions. Upon satisfactory results of these tests, a pre-feasibility study is planned. Negotiations are also under way to obtain up to $500,000 in CIDA funding for a Canadian engineering company to do a pre-feasibility study on an oil sands project in Trinidad using ATP technology.

Venezuela

An implementing agreement for the participation of Venezuelan and Canadian engineers in a cooperative educational program at the University of Calgary under the terms of the agreement between AOSTRA and Petroleos de Venezuela, S.A. has been drafted and is under review.

The annual meeting between AOSTRA and PDVSA was held in February 1991 in Caracas. A test using the HDH process with Alberta feedstock was performed on the 0.3 barrel per day unit. If the results are positive, the second phase of testing on the 10 barrel per day unit will be undertaken.

Specific areas of common interest for research projects have been identified as reservoir characterization and biotechnology/microbial processes. Some work is already being conducted under the AOSTRA/University Research Program, of which PDVSA is an associate member, and some work is planned under the new AOSTRA/ARC/Industry Research Program.

Nigeria

Negotiations have been successfully completed with the Nigerian Presidential Committee on the Implementation of the Bitumen Project for the exchange of technical information and cooperation. Nigeria has a rich oil sand deposit containing in excess of 30 billion barrels of bitumen. The deposit outcrops, can be mined, and has sections suitable for in situ recovery. Nigeria, while a major light oil producer, imports bitumen from Venezuela for asphalt and lubricating oil production.

United States

Under the Canada/United States Department of Energy (DOE) memorandum of understanding, of which AOSTRA is a signatory, AOSTRA and DOE took an active role in each other’s university research programs and attended each other’s access meetings. In addition AOSTRA, together with CANMET, completed an assessment report on seismic work related to the GLISP project. AOSTRA also followed closely and gave advice on the in situ parametric combustion laboratory research project sponsored by CANMET at the University of Calgary and the corresponding project sponsored by DOE in the United States.

Recently DOE has made arrangements to supply oil-bearing diatomite samples from the United States for testing in the AOSTRA Taciuk Processor. Negotiations are also proceeding for a jointly funded project in horizontal wells, possibly in the area of improved drilling technology. DOE and the Saskatchewan Department of Mines and Minerals have also expressed an interest in a joint project on field upgrading of heavy oils.

Japan

In November 1990, AOSTRA representatives visited Japan and were present during the signing of an agreement between AOSTRA and the Japanese National Research In-
stitute for Pollution and Resources. Cooperative research activities will center on upgrading technology and on the use of the ATP technology for waste cleanup.

Argentina

The memorandum of understanding with the Argentine National Oil Company has been ratified by AOSTRA. Initially, the Argentinians are interested in modernizing their enhanced oil recovery research and development laboratories and in expanding their thermal recovery program.

Brazil

The Research and Development Center of the Brazilian National Oil Company (CENPES/PETROBRAS) has agreed to execute a formal agreement with AOSTRA. CENPES is particularly interested in establishing a modern thermal recovery laboratory. AOSTRA is also interested in the sale of the ATP technology for oil shale fines recovery and for refinery sludge.

Ecuador

The memorandum of understanding with PETROLECUADOR has been finalized following approval by FIGA. Signed copies of these agreements have been sent to Ecuador and it was suggested that AOSTRA staff visit Ecuador following the Fifth UNITAR Conference in Caracas for further discussions on technical cooperation and staff training. Ecuador has heavy oil and oil sand deposits of perhaps 200 billion barrels.

India

Discussions with the Institute of Reservoir Studies of the Oil and Natural Gas Commission of India (IRS/ONGC) have been active. Two experts from IRS/ONGC visited Alberta to familiarize themselves with combustion-related research and field facilities in April. They were also interested in horizontal well and anti-water-coning technologies.

France

AOSTRA was a sponsor and a participant at the Canada-Europe Meeting on Environment and Waste held in May 1991 in Montpellier, France.

Contacts have been made with the Institut Francais du Petrole to start discussions for collaborative work. Discussions on collaboration/exchange of technical information were also held with a representative of the Societe Nationale Elf Aquitaine Production.

Germany

Further talks were conducted with GKSS, the official German Government representative for the Canada-Germany Science and Technology Cooperative Agreement. AOSTRA drafted a letter of intent, outlining specific cooperative projects. The Germans would prefer to sign project agreements rather than a memorandum of understanding, but the Germans are reviewing the document.

Albania

Negotiations to develop a working relationship have started with Teknoimport, the Albanian Enterprise for Foreign Trade which is interested in developing its country's bituminous sands. A standard memorandum of understanding was sent to them, but no exploratory visit has taken place.

Romania

AOSTRA has received an invitation to visit the Romanian Research and Design Institute for Oil and Gas (ICPPG). A delegation from ICPPG was invited to come to Alberta during the second quarter of 1991.

SOVIEI PRODUCTION OF NATURAL BITUMEN AND BITUMINOUS ROCKS COVERS 20 YEARS

Natural bitumens and bitumen-containing rocks have been the subject of research and development activities in the Soviet Union for at least 20 years. Current Soviet production of these resources was discussed in a paper by G.G. Vakhitov of the All Union Oil and Gas Scientific Research Institute, USSR, and presented at the Fifth UNITAR International Conference on Heavy Crude and Tar Sands held in Caracas, Venezuela in August.

Natural Bitumens

Natural bitumens (NB) are organic compounds, converted through biodegradation from crude oils. They have a primary hydrocarbon base and a solid and viscous nature. NB are characterized by high asphalt-resin content, in some cases up to 95 percent.

Thus NB is considered as a multipurpose complex mineral resource to be used for obtaining the following products:

- Fuels (in gaseous, liquid, and solid forms)
- Petrochemical and chemical products, including lubricants
- Varnishes and paints, insulating materials, sulfur, etc.
- Metalliferous products
- Biostimulants
- Materials for civil engineering and road paving

Bitumen-Containing Rocks

Bitumen-containing rocks (BCR) are sedimentary types of rocks such as sands, sandstones, dolomite, etc. They have high concentrations of natural bitumen, either to be extracted or utilized for preparation of asphalt-concrete or asphalt-mineral mixtures. BCR can be used both for road paving and civil engineering.

Soviet Resource Base

In the USSR, the number of currently known deposits of NB or BCR is about 700. Some 71 percent of these resources are concentrated in the Volga-Urals mainly in the Tatar Republic.

The estimated resources of BCR occurring at the depth range from the surface to 150 meters and suitable for road paving and civil engineering are estimated at 20 to 25 billion tonnes.

Research Trends

In the Soviet Union the basic research, as well as pilot operations in the field of NB and BCR recovery techniques, have three main trends:

- In situ recovery techniques: crude bitumen is produced through the wells drilled from the surface and the pay zone is thermally stimulated to reduce the crude bitumen’s viscosity
- Surface mining and actual mining, where BCR are lifted to the surface
- Mine-assisted gravity drainage, where NB is produced by means of a drainage system

In Situ Recovery Techniques

According to the paper, more than 90 percent of world NB production is accomplished by in situ recovery techniques, thermal techniques being predominant. In situ recovery techniques for NB production have been pilot tested in the Volga-Urals (Tataria region).

The commencement of that operation dates back to 1973. By 1979, various technologies for in situ NB production had been tested in a number of fields in Tataria. In situ combustion proved to be most efficient when a specially designed thermal gas generator was applied.

In situ combustion has been successfully tested in a pilot phase in the Mordovo-Karmalsky field. The pilot project was initiated in 1978. The average pay thickness is 20 meters and the average bitumen content is 9.6 weight percent.

The first pilot area was a five-spot pattern with well spacing of 50 meters, having an injector and four producers. In 1979 ignition was initiated in the second element, which had been drilled out at a well spacing of 100 meters, with monitor wells at spacing of 50 meters. The deposit is composed of sandstones, with a pay thickness of 20 meters and average bitumen content of 11.5 weight percent.

To date, about 30,000 tonnes of bitumen have been produced.

The experience has shown that thermal enhanced recovery techniques cannot be applied to NB production without modification. Low reservoir pressure in shallow bitumen accumulations is the main obstacle, says the paper.

After steam injection, bitumen was obtained entirely by gravity. Therefore, it was essential to design a more efficient technique for shallow bitumen deposits.

The technology of steam-gas mixture injection into bitumen deposits was field tested. The mixture, consisting of nitrogen, carbon dioxide and steam, was injected by means of a unique steam-gas generator (SGG) specially designed by the Kazan aviation institute.

During steam-gas injection, the bitumen viscosity is reduced due to steam stimulation and CO₂ dissolution in the liquefied bitumen. Inert gas contributes to a reservoir pressure increase in the stimulation zone. Thus, the bitumen influx to the bottomhole zone was improved both during the cyclic well stimulation as well as in the pattern steam flooding. The application of SGG allowed the production of 14 tonnes of bitumen per 1.4 tonnes of burnt distillate with the steam-bitumen ratio being 2.9.

Steam-gas injection has proved to be the key technology to increase bitumen production in the near future, says the paper.

Encouraging results were also obtained during field testing in the Gorsky field in Tataria. Here, bitumen was produced from carbonate reservoirs by cyclic steam-gas stimulation.

In the Soviet Union, about 45 percent of the known NB deposits occur at the depth range from 200 to 600 meters, where in situ recovery techniques are most efficient.
Mining Techniques

More than 50 percent of NB and BCR deposits occur at depths which can be developed by surface mining and mining through shafts and tunnels.

In the Soviet Union, such commercial and pilot operations for NB and BCR development have been carried out in more than 20 fields. The produced BCR is mostly used for road paving.

The BCR deposits located within the limits of Tataria (the Volga-Urals) are the best prospect for such development. Currently pilot production is under way in the Spiridonovsky BCR deposits to be used for road paving. Annual production will amount to 50,000 tonnes.

In Kazakhstan, BCR production by surface mining dates back to the 1950s. In 1985, annual production was 50,000 tonnes and in 1986—120,000 tonnes. In 1990, the annual BCR production will reach 4 million tonnes.

A large portion of the excavated BCR is utilized on the spot for road paving. Feasibility studies showed that the capital investment per ton of an asphalt/mineral mixture is one-fourth of the corresponding outlay per ton of an asphalt-concrete mixture on a bitumen base.

The savings are more than 5,000 rubles per 1 kilometer of roadway covering.

According to Soviet experts, the utilization of unprocessed bitumen-containing rocks for road paving will completely satisfy the demand for bitumen paving in West Kazakhstan. This will save more than 10 million rubles, and the capital investments will be paid off in less than 2 years.

In the Mortuk field, deposits of NB are assessed at 80 million tonnes. Analyses have shown that the upper deposit is favorable for surface mining, whereas the lower one is favorable for in situ recovery, namely thermal stimulation. In situ recovery will commence after the complete development of the upper deposit, which will reduce the footage drilled and sharply cut capital investments.

Natural bitumens of the Mortuk field are promising raw materials for obtaining naphthenic acids and sulfoxides, to be separated from the diesel and oil fractions. A feasibility study showed that thermal cracking is the most acceptable refinery technique to obtain synthetic oil from both BCR and NB.

Mine-Assisted Gravity Drainage Techniques

Various countries, including France, Germany, Japan and Romania, made attempts to produce oil by draining pay zones. In the USSR such pilot operations have been carried out in the Azerbaijan and Ukraine regions.

Currently, highly viscous oil mining is under way in the Yarega oil field, where the thermal mining technique is applied.

The mine-assisted gravity drainage system for NB production applied in some fields of Azerbaijan, Central Asia, and the Volga-Urals proved to be feasible.

ORIMULSION TESTED IN ITALY AND FLORIDA

BP BITOR, the joint venture between the Venezuelan national oil company and British Petroleum, will supply 1 million tonnes of Orimulsion over a 5-year period to the Italian state electricity company, ENEL. With delivery scheduled to begin in 1994, the fuel will feed a gasification plant manufacturing synthetic gas.

In the United States, the Florida Power and Light Company (FPL) has successfully completed its first test of Orimulsion (a bitumen/water emulsion) fuel. FPL estimates that substituting Orimulsion for oil at only two of its 400-megawatt units will save the company more than $700 million over the next 20 years.

During its test burns of Orimulsion, the utility experienced no major problems. However, some modifications will be made to the boilers to increase their combustion efficiencies with the mixture of bitumen and water. FPL is also evaluating different types of pollution control equipment which would be used on the units burning Orimulsion.

###
TACIUK PROCESS FINDS NEW ENVIRONMENTAL APPLICATIONS

The AOSTRA Taciuk Process (ATP) was developed by the Alberta Oil Sands Technology and Research Authority (AOSTRA) and UMATAC Industrial Processes Division of UMA Engineering Ltd. over the past 14 years. AOSTRA and UMATAC, with the participation of Environment Canada and Energy Mines and Resources Canada, have carried out a comprehensive pilot program to demonstrate the suitability of the ATP for the treatment of heavy oil production wastes.

The goal of the pilot program was to produce oil-free solids that are acceptable for landfill. The results of this pilot program were reported in a paper by L.R. Turner of AOSTRA and presented at the Fifth UNITAR International Conference on Heavy Crude and Tar Sands held in Caracas, Venezuela in August.

It was recognized at the outset that the ATP was potentially capable of treating a wide variety of hydrocarbon-bearing solid and semi-solid materials to separate and recover as discrete products a dry, oil-free solid residue, distillable liquid hydrocarbons and process water, including the treatment of heavy crude oil and bitumen production wastes and hydrocarbon contaminated soils and sediments which typically occur on oil refinery sites.

The AOSTRA Taciuk Processor (Figure 1) consists of a single, horizontal, rotating vessel in which separate, interconnected compartments or zones are created by the geometry of the equipment.

It is important to recognize that the AOSTRA Taciuk Process is not an incinerator but a pyrolysis process which provides for the production of both oil-free solids and liquid oil product.

FIGURE 1

AOSTRA TACIUK PROCESSOR ZONES AND FLOW STREAMS

SOURCE: AOSTRA

SYNTHETIC FUELS REPORT, DECEMBER 1991
Treatment of Heavy Oil Production Wastes

The treatment of oil field production wastes has been extensively demonstrated in Calgary, Alberta in both a 105 tonne per day pilot plant and in a 220 tonne per day commercial plant before the commercial plant was demobilized for transport to the United States. These demonstration programs dealt not only with heavy oil production wastes but also with invert drilling mud cuttings.

In 1986, AOSTRA and UMATAC initiated a two phase, $600,000 program to demonstrate the ability of the ATP to treat various heavy oil production wastes obtained from the heavy oil and oil sands bitumen-producing area bordering the provinces of Alberta and Saskatchewan. The Lloydminster-Lindbergh heavy oil area produces about 90,000 cubic meters per day of oily wastes and lesser but increasing volumes are generated in the Cold Lake bitumen producing area of Alberta.

Phase I—Batch Testing

Experiments were carried out in existing batch equipment at the Calgary pilot plant to examine both the pyrolysis and residual coke combustion operations occurring in the processor.

A total of 17 different heavy oil production wastes, as listed in Table 1, were tested in Phase I. These samples were extremely variable in terms of oil, water and solids content and in terms of their respective concentrations of inorganic ions depending on the type and source of the waste samples.

The analytical work performed on product samples from the batch pyrolysis tests concentrated on the chemistry of the effluents to assess their suitability for downstream treatment and/or ultimate safe disposal.

### TABLE 1

<table>
<thead>
<tr>
<th>Source</th>
<th>Type</th>
<th>% in feed</th>
<th>Hours</th>
<th>Tonnes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 Tangleflags</td>
<td>E Field Tank Sand</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 Lloydminster</td>
<td>Slop Oil/Sludge</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3 Wolf Lake</td>
<td>Slop Oil/Sludge</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4 Wolf Lake</td>
<td>Desand Sludge</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 Wolf Lake</td>
<td>Heavy Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6 Lloydminster</td>
<td>Composite</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7 Lindbergh</td>
<td>Desand Sludge</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8 Lloydminster</td>
<td>Field Tank Sand</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>9 Cold Lake</td>
<td>Desand Sludge</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 Celtic</td>
<td>Desand Sludge</td>
<td></td>
<td></td>
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<tr>
<td>11 Lindbergh</td>
<td>Field Tank Sand</td>
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<td>12 Lloydminster</td>
<td>Desand Sludge</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>13 Lindbergh</td>
<td>Desand Sludge</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>14 Brooks - Light Oil Waste</td>
<td>Pit Sludge</td>
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<td></td>
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<tr>
<td>15 Lloydminster</td>
<td>Ecology Pit Mixture</td>
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<td>16 Lloydminster</td>
<td>Heavy Oil</td>
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<td>17 Lloydminster</td>
<td>Sludge</td>
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<tr>
<td>Phase 2</td>
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</tr>
<tr>
<td>Mobil Celtic</td>
<td>Desand Sludge</td>
<td>56</td>
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<td>138</td>
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<tr>
<td>Mobil Kitscoty</td>
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<td>47</td>
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<tr>
<td>Combustion Trials</td>
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<td>36</td>
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<tr>
<td>Totals</td>
<td></td>
<td></td>
<td>111.9</td>
<td>381</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, DECEMBER 1991
The results of the Phase I batch pyrolysis and combustion tests may be summarized as follows:

- All of the samples yielded a distillable oil with a gravity ranging from 22°API to 27°API. The corresponding C₄+ liquid oil yield ranged from 75 to 90 percent (expressed as weight percent of the oil in the feed).
- The combusted solids are free of oil and grease.
- All of the coke deposited on the solids during pyrolysis is consumed during combustion. Priority polycyclic aromatics in the combustion gases were below detection limits.
- The pyrolysis water is sour with high biological oxygen demand (BOD) and chemical oxygen demand (COD) and would require treatment prior to reuse or surface disposal.
- Apart from small quantities lost to the flue gases, metals remained with the mineral solids following combustion.
- Leachate tests of the burned solids demonstrated that the contained metals and salts are stable, with relatively small concentrations appearing in the leachate.

Phase II—Continuous Flow Pilot Plant Runs

The Phase II test program involved the processing of four separate bulk samples of oily wastes obtained from the Lloydminster and Cold Lake areas. A combined total of 380 tonnes were processed during 230 hours of operation in the continuous flow pilot plant. The source, type and quantity of each of the four bulk samples fed to the processor are shown in Table 1.

Leachate tests of the burned solids demonstrated that the contained metals and salts are stable, with relatively small concentrations appearing in the leachate.

The average oil, water, and solids contents of each waste sample prior to blending with clean sand are shown in Table 2, together with the average concentration of chlorides and sulfates.

The C₄+ oil yield expressed as a weight percent of oil in the feed ranged between 56 and 65.3 percent with an average yield of 60.9 percent for all of the feed materials processed. The corresponding API gravity ranged from 28.5°API to 39.2°API with an overall average of 32.5°API.

The total solids discharged from the system were produced in three streams, in the following overall average proportions:

- Bulk tailings: 93.0 weight percent
- Flue gas cyclone fines: 4.9 weight percent
- Baghouse fines: 1.7 weight percent
- H-C cyclone fines: 0.4 weight percent

The solids mix was a dry, silty sand, hydrocarbon-free, with an average organic carbon content of only 21 ppm.

The chlorides and sulfates are primarily contained in the flue gas particulates captured in the flue gas cyclones and baghouse. These particulates amount to less than 7 percent by weight of total solids discharged and could be segregated for disposal in a separate secure landfill, if necessary.

The results of the analysis of leachates indicates:

- Presence of phenols is minimal or not detectable.
- Oil and grease are not detectable.
- Total carbon (organic and inorganic) is low.
- Heavy metals are low or not detectable.

### TABLE 2

COMPOSITION OF WASTES TESTED IN PHASE II

<table>
<thead>
<tr>
<th>Waste Source Type</th>
<th>Constituents (Wt%)</th>
<th>Key Anion Concentrations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Oil</td>
<td>Water</td>
</tr>
<tr>
<td>Celtic desand</td>
<td>15</td>
<td>16</td>
</tr>
<tr>
<td>Kitscoty field tank</td>
<td>6</td>
<td>6 - 8</td>
</tr>
<tr>
<td>Wolf Lake desand</td>
<td>20 - 30</td>
<td>40</td>
</tr>
<tr>
<td>Cold Lake desand</td>
<td>18 - 25</td>
<td>15 - 25</td>
</tr>
</tbody>
</table>
The average concentrations of chloride and sulfate ions in the leachates from combined solids are less than the permissible maximums for potable water.

In general, it was concluded that the combined solids produced in pilot plant tests would be suitable for disposal directly as a Class 3 Landfill.

Effluent Waters

The analyses of the preheat zone vent waters and the sour process water drained from the oil fractionator overhead accumulator showed high phenol concentrations, BOD, COD and sulfur in particular and are similar to process waters generated in refinery operations involving thermal cracking of high-sulfur heavy oils and residues. Such waters would need to be treated if reuse or discharge to surface water was contemplated. Deep well disposal would also be an option.

Gaseous Emissions

Offgas (non-condensable gases in the hydrocarbon vapor stream) were flared in the pilot plant. In commercial operations, offgas could be used as fuel for the processor auxiliary burners depending on sulfur content of oil in the feed.

Flue gases generated by the combustion of coke deposited on spent solids and supplemental fuel did not contain appreciable concentrations of SO\textsubscript{2}, NO\textsubscript{x}, H\textsubscript{2}S and particulates after treatment in the flue gas cleanup circuit. Flue gas discharged from the stack was considered to meet the requirements of the Alberta Clean Air Act.

Cost of Treatment and Disposal

Unit costs for treatment and disposal, expressed as dollars per ton of waste material processed, for plants having capacities ranging from 4.5 to 20 tonnes per hour are shown in Figure 2. These costs are for fixed plants operating 24 hours per day, 9 months per year.

The author acknowledged that the unit costs of treatment and disposal of oil production wastes using the AOSTRA Taciuk Process in the full service mode are greater than the costs of disposal of oily waste by means of land spreading techniques. However, the environmental consequences of land spreading are not fully understood and there is evidence that the practice of land spreading is becoming of increasing concern to regulatory agencies.

Other Waste Applications

The process has been successfully tested in either batch or pilot plant operations on a wide variety of hydrocarbon-bearing waste materials. Prominent among these are:

- API separator sludges
- Oily refinery soils and sludges
- Shredded scrap rubber tires
- Municipal solid waste
- PCB contaminated soils and sediments
- Invert drilling muds and drill cuttings

Commercialization

UMATAC has constructed a 220 tonne per day transportable commercial ATP plant specifically for use in the remediation of PCB contaminated soils in the United States. Currently in use in New York State, the plant is scheduled to be moved to the Chicago area in 1992 for the separation and recovery of PCBs from harbor sediments.

AOSTRA has initiated the construction of a 3 to 5 tonne per hour transportable ATP for use in Western Canada. The plant will serve a dual purpose. It will be available for use commercially in the remediation of hydrocarbon contaminated sites and it will also serve as a means of performing on-site demonstrations of the process not only in waste treatment applications but also for the extraction and primary upgrading of oil sands bitumen and shale oils.

###
OIL SANDS PUBLICATIONS/PATENTS

RECENT PUBLICATIONS

The following papers were presented at the 1991 Eastern Oil Shale Symposium held November 13-15 in Lexington, Kentucky:

Reynolds, J.G., "Utilizing Asphaltene Pyrolysis to Predict Pyrolysis Kinetics of Heavy Crude Oils and Extractable Native Bitumen"

Speight, J.G., "Molecular Models for Petroleum Asphaltenes and Implications for Processing"


Sparks, B.D., "The Effect of Asphaltene Content on Solvent Selection for Bitumen Extraction by the SESA Process"

Schutte, R., "The Deterministic Role of Asphaltenes in the Hot Water Extraction of Athabasca Oil Sands"

Hanson, F.V., "The Application of Compound-Type Analyses to the Correlation of Product Distributions and Yields from the Fluidized-Bed Pyrolysis of Oil Sands"

Cyr, T., "Control of Coke Formation in a Heavy-Oil Hydrocracker"


Ferdman, I.I., "Natural Bitumen and High Viscous Oil Resources of the Soviet Union and their Development Techniques"

Olsen, D.K., et al., "Guidelines for Determining the Feasibility of Heavy Oil Recovery Oil"

Olsen, D.K., et al., "Heavy Oil Refining and Transportation: Effect on the Feasibility of Increasing Domestic Heavy Oil Production"

Mason, G.M., "Evidence for the Microbial Origin of a Utah Tar Sand"

Johnson, W.I., et al., "Depositional Compartmentalization of Heavy Oil in Midcontinent Cherokee Group Fluvial-Dominated Deltaic Sandstones"

Tsai, C., et al., "Characterization of Whiterocks (Utah) Tar Sand Bitumen"

Karazincir, H., et al., "Multi-Mode Seismic Cross-Borehole Imaging"


Koszarycz, R., et al., "The AOSTRA Taciuk Process—Heading Into the Commercialization Phase"

Dickinson, W., et al., "Typical Ultrashort Radius Radial System Production Results in Heavy and Light Oil Reservoirs"

Singh, B., "Hydraulic Mining of Oil Sands"

Cha, S., et al., "Pyrolysis of Oil Sand from the Whiterocks Tar Sand Deposit in a Rotary Kiln"

Kong, X., et al., "Visualization Experiments for Steam Injection in Hele-Shaw Cells"

Longstaff, D.C., et al., "Hydrotreating the Bitumen-Derived Hydrocarbon Liquid Produced in a Fluidized-Bed Pyrolysis Reactor"

Guohe, Q., et al., "Thermal Conversion of Shengli Vacuum Residue and Its Constituents"

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3-32
Scott, J.D., et al., "The Relationship Between Absolute Permeability and Stress State for Heavy Oil Sand"

Ruthledge, J.T., et al., "Imaging Heavy Oil Sands—McKittrick Field, McKittrick, California"

Thomas, C.P., et al., "Surfactant Mediated Microbial EOR of Medium to Heavy Crude Oils"

Johnson, W.I., et al., "Environmental Factors Affecting Heavy Oil Recovery in the Midcontinent"

Strickland, T., et al., "Volumetric Sweep Efficiencies of Horizontal Well Patterns"

Richardson, K.K., "Enzyme Extraction of Light Crude Oil from Tar Sands"

Henry, D., et al., "Preparation of Bitumen from Oil Sand by Ultracentrifugation"

Misra, M., et al., "Noninvasive Determination of Water and Bitumen in Tar Sands by an Open-Ended Coaxial Probe"


Hupka, J., et al., "Preliminary Examination of Oil Bonding at Sand Surfaces and Its Influence on Hot Water Separation"

Drelich, J., et al., "Fine Sand and Water Separation from Bitumen Concentrate"

Hwang, J., et al., "Dynamic Supercritical Fluid Extraction of Crude Oil and Bitumen-Derived Liquids"

The following papers were presented at the 1991 International Joint Power Generation Conference, October 6-10, held in San Diego, California:


Sharkey, J.M., "Orimulsion in Western Europe: The First Two Years"

Whaley, H., et al., "Combustion and Heat Transfer Characteristics of Pipelineable Water-Bitumen Emulsions"

The following article appeared in The Journal of Canadian Petroleum Technology, September-October 1991:


OIL SANDS - PATENTS

"Method for Improving Steam Stimulation in Heavy Oil Reservoirs," Alfred R. Jennings, Jr. and Roger C. Smith - Inventors, Mobil Corporation, United States Patent Number 5,042,581, August 27, 1991. A method for controlling formation fines when producing heavy oil from an unconsolidated sand formation where at least two wells are utilized. Both wells are perforated and hydraulically fractured at a lower interval via a viscous gel fluid having a sized and high temperature resistant proppant therein. The proppant is a size sufficient to filter fines from the oil, thereby keeping the fracture clear. Cyclic steam injection and oil production are conducted in one well, while the other is shut-in. This sequence is continued until a desired amount of solids free hydrocarbonaceous fluids have been produced from the lower interval. Thereafter, the lower interval is blocked off mechanically while cyclic steam injection and oil production are conducted in one well and the other well is shut-in until a desired amount of solids free hydrocarbonaceous fluids have been produced from a higher interval.

"Method and Apparatus for Producing Tar Sand Deposits Containing Conductive Layers," John W. Gardner, Carlos A. Glandt, and Harold J. Vinegar - Inventors, Shell Oil Company, United States Patent Number 5,042,579, August 27, 1991. An apparatus and method are disclosed for producing thick tar sand deposits by preheating of thin, relatively conductive layers which are a small fraction of the total thickness of a tar sand deposit, with horizontal electrodes. The preheating is continued until the viscosity of the tar
in a thin preheated zone adjacent to the conductive layers is reduced sufficiently to allow steam injection into the tar sand deposit. The entire deposit is then produced by steam flooding.

"Process for Removing Heavy Metal Compounds from Heavy Crude Oil," John E. Boysen, Jan F. Branthaver, and Chang Y. Cha - Inventors, Western Research Institute, United States Patent Number 5,041,209, August 20, 1991. A process is provided for removing heavy metal compounds from heavy crude oil by mixing the heavy crude oil with tar sand; preheating the mixture to a temperature of about 650°F; heating said mixture to up to 800°F; and separating tar sand from the light oils formed during said heating. The heavy metals removed from the heavy oils can be recovered from the spent sand for other uses.

"Mixer Circuit for Oil Sand," George J. Cyberman, Anthony H.S. Leung, and Waldemar B. Maciejewski - Inventors, Alberta Energy Company Ltd., Canadian Occidental Petroleum Ltd., Esso Resources Canada Ltd., Gulf Canada Resources Ltd., Her Majesty the Queen in right of Province of Alberta, Canada; HBOG Oil Sands Ltd. Partnership; PanCanadian Petroleum Ltd. and Petro-Canada Inc., United States Patent Number 5,039,227, August 13, 1991. The mixer circuit comprises a vertically oriented, open-topped mixer vessel having a cylindrical side wall terminating with a shallow conical bottom. The bottom wall forms a central bottom outlet. Recycled slurry and fresh water streams are fed tangentially to the inner surface of the vessel, thereby forming a vortex. The oil sand enters as a continuous, free-flowing stream moving along a downward trajectory; the stream impinges the vortex, wherein it is dispersed and mixed to create slurry. The slurry exits through the bottom outlet, is screened to remove oversize material, and enters a holding vessel. Part of the slurry in the holding vessel is recycled to the mixer vessel through a pipe loop incorporating a pump. The slurry is energized by the pump and functions to maintain and partly create the rapidly moving vortex that carries out the mixing and lump-disintegration actions. The balance of the slurry in the holding vessel is pumped out as product. The circuit is adapted to consistently produce a dense slurry.

"Method for Improving Sustained Solids-Free Production from Heavy Oil Reservoirs," Alfred R. Jennings, Jr. and Roger C. Smith - Inventors, Mobil Corporation, United States Patent Number 5,036,918, August 6, 1991. A method for controlling formation fines when producing viscous oil from a consolidated or loosely consolidated formation having at least two wells therein. Both wells are perforated and hydraulically fractured at a lower level via a viscous gel fluid having a size and temperature resistant proppant therein. The proppant is of a size sufficient to filter formation fines from the oil. Cyclic steam-flooding and oil production are continued in one well, while the other well is shut-in. Prior to steam breakthrough, the lower perforated intervals are isolated with production packers containing knock-out plugs. A correlatable selected upper interval in both wells is perforated and hydraulic fracturing is repeated. Cyclic steam-flooding and oil production are continued in the upper interval until steam breakthrough occurs. Cyclic steam-flooding is ceased and production strings are directed through the knock-out plugs into the lower interval. Thereafter, steam is directed down the annulus from a first well into a second well in the upper interval, while producing oil from the lower interval. Thereafter, steam is circulated down both wells into the upper formation causing the formation of a "heat chest" and the production of hydrocarbonaceous fluids from the lower interval via the production string.

"Method for Providing Solids-Free Production from Heavy Oil Reservoirs," Alfred R. Jennings, Jr. and Roger C. Smith - Inventors, Mobil Corporation, United States Patent Number 5,036,917, August 6, 1991. A method for controlling formation fines when producing heavy oil from an unconsolidated sand formation where at least two wells are utilized. Both wells are perforated and hydraulically fractured at a lower interval via a viscous gel fluid having a size and high temperature resistant proppant therein. The proppant is a size sufficient to filter fines from the oil, thereby keeping the fracture clear. Cyclic steam-flooding and oil production are conducted in one well, while the other is shut-in. This sequence is continued until steam breaks through at the lower interval from a first well into a second well. Afterwards, production packers with knock-out plugs are used to isolate the lower interval of both wells. Cyclic steam injection and oil production are continued in the upper interval of both wells. Subsequently, both wells are shut-in and production strings are directed to the lower formation interval through the knock-out plugs. Steam is then injected down the lower level of both wells and oil is produced from the upper level through the annuli of both wells.


"Catalyst Composition for Hydrogenation of Heavy Hydrocarbon Oil and Process for Producing the Catalyst," Takuo Suzuki, Takeshi Tomino, Kazushi Usui, Hatsutaro Yamazaki, and Tomohiro Yoshinari - Inventors, Cosmo Oil Company Ltd; Petroleum Energy Center Foundation, Cosmo Oil Company and Petroleum Energy Center (Japan), United States Patent Number 5,002,919, March 26, 1991. A catalyst composition for the hydrogenation of heavy hydrocarbon oil comprising at least one active ingredient for hydrogenation supported on a porous refractory oxide carrier and which has the following characteristics: (1) the mean pore diameter of the pores thereof is in the range of 130 to 250; (2) the volume of pores having a pore diameter within plus or minus 30...
of the mean pore diameter is in the range of from not less than 30 percent to less than 60 percent of the total volume of the pores; (3) the volume of pores having a pore diameter of not larger than 80 is not more than 13 percent of the total volume of the pores; (4) the volume of pores having a pore diameter of not smaller than 350 is not more than 25 percent of the total volume of the pores; and (5) the ratio (mm$^2$/mm$^3$) of the outer surface of a molded catalyst particle to the volume thereof is in the range of 3 to 8. There are also disclosed a process for producing the catalyst composition and a process for hydrogenating heavy hydrocarbon oil, the latter of which comprises contacting heavy hydrocarbon oil with the catalyst composition in the presence of hydrogen.
STATUS OF OIL SANDS PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since September 1991)

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: $1.5 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 in the project.

Project Cost: Upgrader Facility estimated at C$1.4 billion
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

BITUMOUNT PROJECT - Solv-Ex Corp. (T-20)

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.

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 Fort 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.

BURNT LAKE PROJECT - Suncor Inc., Alberta Energy Company Ltd. and Canadian Hunter Exploration Ltd. (T-30)

The Burnt Lake in situ heavy oil plant 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 will involve cyclic steaming, was put on hold in 1986 due to low oil prices, then revived in 1987. The project as of early 1989 was again halted. Alternative recovery processes are under evaluation. A pilot is underway to test the cold bitumen production technique. Initial results are encouraging.

According to initial plans, the project was supposed to be designed after the thermal recovery project Suncor operated nearby at Fort Kent. There slant wells were drilled in clusters and cyclic steamed.

Future stages could double production to 25,000 barrels per day. Burnt Lake is estimated to contain over 300 million barrels of recoverable heavy oil.

CHEVRON HASDRIVE PILOT PROJECT – Chevron Canada Resources (T-40)

Chevron Canada Resources is planning to construct a pilot plant utilizing the HASDrive process to recover bitumen from the Athabasca oil sands. HASDrive stands for heated annulus steam drive. The pilot plant will be located on Chevron's oil sands lease some 30 miles northeast of Fort McMurray, Alberta, Canada.

Initially, Chevron plans to drill 53 core holes, at a cost of C$3 million, to identify the most favorable location for the facility. Construction is expected to begin in late 1991. If the pilot is successful, Chevron plans to construct a 10,000 barrel per day commercial plant before the year 2000.

In 1987, Chevron joined with the Alberta Oil Sands Technology and Research Authority in testing the HASDrive process at its Underground Test Facility (UTF) north of Fort McMurray. The positive results from the UTF tests provided the technical and economic justification for Chevron's pilot project.

In the HASDrive process, a horizontal wellbore is drilled into the oil sands formation. Steam is injected through a tube in the wellbore casing which heats the oil sand along the length of the injection pipe. A separate vertical well is used to inject additional steam into one end of the heated horizontal channel (annulus), driving the heated bitumen toward a production well at the other end.

Project Cost: $5.5 million for the pilot plant
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

COLD LAKE PROJECT - Esso Resources Canada Limited (T-50)

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.

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. A decision was made not to complete the facility in 1989. Phases 9 and 10 have been postponed indefinitely.

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 Can$220 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 later in the year. 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)

Universal Energy Corporation of Tulsa, Oklahoma changed the company's name to Oil Recovery Systems (ORS) Corporation in June 1986. Through its subsidiary, Uentech Corporation, Universal Energy 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.

This well was shut-in after seven months of operation due to high operating costs associated with severe sand production. Two other wells utilizing the Technology were completed in the Wildmire Field with encouraging results initially. However, attempts to mitigate the sanding problems were not successful and these wells were also shut-in after approximately one year of operations.

Additional work is being undertaken in Canada. A 12 degree API heavy oil well in Alberta increased production from 20 barrels to nearly 80 barrels per day. Another well in Saskatchewan increased from 75 to about 125 barrels per day after application of the Technology. Approximately 20 wells are expected to apply the Technology within Canada during 1989. This work is being performed by Electromagnetic Oil Recovery Limited (EOR), a Calgary headquartered affiliate. EOR signed a contract in 1988 with Shell to field test the Technology in Europe during 1989.

ORS Corporation participated in two wells drilled in California in 1986 near Bakersfield. Severe sand production problems and low initial well productivity prevented a commercial installation although reservoir temperature was demonstrated to increase in excess of 150 degrees Fahrenheit. Another ORS affiliate, Pogue Oil Recovery Technologies, drilled an additional well in 1987 on the White Wolf farmout from Tenneco Oil. The wells were eventually shut-in in 1988 due to low productivity, sanding problems, and low oil prices.

A demonstration field test began in Brazil in late 1987. The test well was initially completed in September 1987. The initial test well resulted in increasing production from the initial level of 1.1 barrels per day up to 14 barrels per day. The process was to be applied to an additional 4 wells during 1989. Brazil could expand the well stimulation program to potentially several hundred oil producing wells in the country.

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.

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 1 of a proposed 3 phase commercial bitumen recovery project in August 1986.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

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 economies 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 I = C$60 Million to date

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 filed 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 1991 production was 560 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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

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

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 was 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 - Petroles de Venezuela SA (PDVSA) and Veba Oel AG (T-145)

Venezuela's state-owned oil company, Petroles de Venezuela SA (PDVSA), and Germany's Veba Oel AG plan to develop the heavy crude and bitumen reserves in the Orinoro Belt in eastern Venezuela. The two companies are currently conducting 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.

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 is planning 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 will represent...
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

36 percent of the estimated $130 million total cost for the engineering phase. The Canadian federal government will contribute up to $45.5 million, 35 percent of the total, for the engineering phase. The OSLO consortium will fund the rest. The Alberta government had already spent $10.5 million on the OSLO project to 1990.

The engineering phase is scheduled to be completed by the end of 1991. Engineering work has 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 will return the diluent to the bitumen production facility. OSLO has set a $10/barrel target for synthetic crude production for the project. The project could then be profitable with crude oil prices in the $18 to $20/barrel range. Current economics assume a 35-year project life.

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 of higher quality than most of what remains at Syncrude, and OSLO's layer of overburden is thinner; advantages that should make OSLO's estimated production costs slightly lower than those of Syncrude. Lease 31 contains oil sands with 11.4 percent bitumen by weight. OSLO says the project could be expanded to produce 200,000 barrels of synthetic crude oil per day for almost 50 years.

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.

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 $C12 billion and annual operating cost of $040 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, 1986. A 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.

Due to depressed bitumen prices, the proposed drilling schedule remains postponed. The commercial project will proceed when oil prices return to levels which make the project viable.

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 expects to be testing more than 80 wells using various techniques, including a cold technique which employs specialized pumps.

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.

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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

After a maintenance shutdown in the summer of 1990, production was back up to an averaged 60,000 barrels per day. Cash operating costs during 1990 were $17.25 per barrel, including the shutdown period, and $15.00 per barrel excluding the shutdown.

In April 1991, the group set an all-time monthly record producing 2.1 million barrels of synthetic crude oil. Cash operating costs averaged $15.00 per barrel during the first three quarters of 1991. During the first nine months of 1991, production averaged 61,900 barrels per day. Earnings for the period were $243 million due to record production levels.

After December 31, 1991, the royalty will change to be the greater of 5 percent of revenues or 30 percent of revenues less allowed operating and capital costs.

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 $452,419,000. On November 19, 1985 the SFC determined that the project was a qualified candidate for assistance under the terms of the solicitation.

On December 19, 1985, the SFC was canceled by Congressional action. 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.

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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL PROJECTS (Continued)

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 burned in a gas turbine to produce electricity. The hot exhaust gases are then used to make steam and cogenerate 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 joint 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. (9.039%); Canadian Occidental Petroleum Ltd. (7.23%); HBOCI - Oil Sands Ltd. Partnership (Amoco Canada Petroleum Company Ltd.) (5.0%); Mitsubishi Oil Company (5.001%)

Located near Fort McMurray, the Syncrude 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 reclaimer-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 hydrocracker, 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. Syncrude Canada Ltd. currently produces 11 percent of Canada's crude oil requirements.

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 32,000 feet of horizontal boreholes up to 1,500 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.

The initial plans call for drilling one to four levels of horizontal boreholes. The Upper Siggins presently has 34 horizontal wells which compose the 32,000 feet of drilling.

Sixty percent of the horizontal drilling was completed by late 1990. The original plan to begin production while the rest of the drilling was completed has changed. Production has been put on hold pending an administrative hearing to determine whether the mine is to be classified as gaseous or non-gaseous. While awaiting the outcome of the hearing, the company is running production tests.

Project Cost: Three Star has budgeted $3.5 million for the first shaft.
COMMERICAL PROJECTS (Continued)

WOLF LAKE PROJECT – BP Canada Resources Ltd. and Petro-Canada (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.

In late 1989 BP Canada attempted to sell its 50 percent interest in the project and later in 1990 withdrew it from the market. Instead the company is continuing to operate the facility while seeking a third partner.

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 are less than $10 per barrel, and bitumen production has averaged 6,954 barrels a day.

Project Cost:  
Wolf Lake 1  
$114 million (Canadian) initial capital  
(Additional $750 million over 25 years for additional drilling)  
Wolf Lake 2  
$200 million (Canadian) initial capital

YAREGA MINE-ASSISTED PROJECT – Union of Soviet Socialist Republics (T-670)

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. Temperature ranges from 279 to 281 degrees C; 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 15 years, 10 million tons of steam have been injected into the reservoir. Three mines have been operated for over ten years. 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. These areas continue to produce oil. A local refinery produces lubricating oils from this crude.

Project Cost:  Not Disclosed

SYNTHETIC FUELS REPORT, DECEMBER 1991
ATHABASCA IN SITU PILOT PROJECT (Kent 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 observation 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

BATTTRUM 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.

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.

CANNMET HYDROCRACKING PROCESS — Petro-Canada and Partec Lavalin Inc. (T-300)

A novel hydrocracking process for the upgrading of bitumen, heavy oil and residuum has been developed at the Canada Centre for Mineral and Energy Technology (CANNMET). This CANNMET Hydrocracking Process is a single-stage, high conversion process effective for the conversion of 90 weight percent of the pitch in heavy feedstocks to distillate boiling below 524°C. (Pitch is defined as material boiling above 524°C). An additive is used which acts as a coke preventer and a mildly active hydrogenator at moderate pressures. Hydrogen consumption and gas make are lower compared to other hydrocracking processes.

In 1979, Petro-Canada acquired an exclusive right to license the process. Petro-Canada formed a working partnership with Partec Lavalin Inc., a Canadian engineering company, for the marketing of the technology and the design and construction of a 5,000 barrels per stream day demonstration plant at the Petro-Canada refinery in Montreal.

SYNTHETIC FUELS REPORT, DECEMBER 1991
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

Construction and commissioning of the extensively instrumented demonstration unit was completed in 1985. Upon startup, the unit was operated in the hydrovisbreaking mode. Without additive, 30 weight percent pitch conversion was achieved. In May 1986, introduction of additive led to the achievement of 80 weight percent pitch conversion without coking. This test proved the beneficial effect of the additive in achieving high conversions.

Further testing, in pilot plants, led to the use of a simpler additive. The plant operated from March 1987 until June 1989 using this commercial additive. During this time a number of special demonstrations were made including a high conversions (93%) run using a blend of vacuum residues from Cold Lake Heavy Oil and Western Canadian Crudes. The results of this work confirmed the capability of the process to achieve high conversion in a thermally stable, coking free, single stage reactor.

The high conversion CANMET Hydrocracking Process has been successfully demonstrated and is now available for commercial application. Patent protection and process guarantees are provided by the licensors.

No further demonstration plant tests are planned, but a 1 barrel per stream day pilot plant is still used extensively for client feedstock testing.

Project Cost: Not disclosed

CARIBOU LAKE PILOT PROJECT - Husky Oil Operations Ltd. (60%) and Alberta Energy Co. (40%) (T-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 steam 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 will consist 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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

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

CIRCLE CLIFFS PROJECT -- Kirkwood Oil and Gas (T-340)

Kirkwood Oil and Gas is completing 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 Limited, the Alberta Oil Sands Technology and Research Authority, and L'Association pour la Valorization 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 Francaise 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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

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.

(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 maximum recovery were being reviewed as of March 1991.

Project Cost: $15.2 million

FT. 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 12.5 degrees API, and a sulfur content of 3.5 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

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 cp at virgin reservoir temperature). Special fracturing techniques were tested. Three temperature observation wells and seismic methods were used to monitor the in-situ process.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

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 flood began in October 1988. Steam 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 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 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.

IPIATIK EAST PROJECT - Alberta Energy Company (AEC), Amoco Canada and Deminex Canada (T-435)

The Ipiatik East pilot is inside the Cold Lake Air Weapons Range, otherwise known as the Primrose Block. AEC is the operator and holds a 60 percent interest in the project. Partners are Amoco Canada and German Deminex Canada. The project has tested cyclic steam stimulation of bitumen in the Wabiskaw sands of the Lower Cretaceous Mannville Group.

AEC first began experimenting with cyclic steaming in the area in 1984 with seven wells drilled on 3.6 acre spacing. The initial strategy was to use the basal zone to promote reservoir heating and gravity drainage, and to minimize steam override. Initial steaming using 44,000 barrel slugs provided good performance on the first cycle but production deteriorated in later cycles. The wells had been completed with the conventional techniques of installing the production casing set through the formation and cemented to the surface.

In late 1986, AEC began testing a propped sand fracture completion prior to steam injection. The horizontal fracture provided a larger contact area for stimulation and a better chance to contain the fracture above the basal zone. To assist fracture initiation, the casing was notched to create a narrow horizontal area which would be exposed to high rate, high pressure fracture fluids. The casing was notched in the upper half of the oil sands above several of the tight calcite layers.

Results of the propped fracturing prior to steam injection were very encouraging. AEC drilled three more wells (Phase B) northeast of the Phase A pattern in 1987 for further testing. Phase B results were superior to Phase A. The Phase B wells achieved daily oil production rates which were 50 percent better than cycle one, 90 percent better than cycle two and 60 percent better than cycle three on typical Phase A wells. AEC drilled another four wells in 1988, completing a regular seven-spot pattern on six-acre spacing. Those wells have performed better than the 1987 wells over three cycles.

Due to prevailing low heavy oil prices the project was suspended in 1990 to allow concentration on other areas of Primrose which have more immediate commercial potential. Future testing of alternate recovery processes at Ipiatik are being considered.

Project Cost: Phase A: C$24,000,000

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 four hectare pad development with 23 slant and directional wells and 3 observation wells on 3.2 and 1.6 hectare spacing within a 63 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 105 million lb/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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

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)

KENOCO PROJECT – Kenoco Company (T-460)

The Kenoco Company, the successor to the Kensyntar Company, is developing a heavy oil project in Western Kentucky. The principals of Kenoco acquired the interests of Pittston Synfuels, a partner in Kensyntar, in December 1984. A pilot was successfully operated from the summer 1981 through 1983 and produced over 6,400 barrels of heavy oil using a modified wet fire flood process. The operation was stopped before completion of the burn in 1983 to obtain core data on the test pattern. Sixteen core holes were drilled and analyzed.

Plans were being developed to expand to a 400 to 700 barrels per day multi-pattern operation, and over a period of 5 to 6 years to a 10,000 barrels per day operation. However, the commercial project has been on hold since early 1990 pending better market conditions.

Project Cost: Not disclosed

LINDBERGH STEAM PROJECT – Murphy Oil Company, Ltd. (T-470)

This experimental in situ recovery project is located at 13-58-5 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 from 1980 to 1983 but has been terminated. Huff-and-puff continued. Production rates from the seven-spot area were encouraging, 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 enriched 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 reinitiated 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)
R & D PROJECTS (Continued)

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 25-51-4-W4M in the Morgan field in order to evaluate a combination thermal drive process. The project consists of nine 30-acre seven spot patterns. All wells have been steam stimulated. The producers in these patterns have received multiple steam and air/steam stimulations 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

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.

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 rapidly produced with a disappointing, and unexpected high water cut, whereas no bottom water is known to exist in this particular area. This problem is still under review.

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.

Project Cost: Not Specified
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

PROVOST UPPER MANNVILLE HEAVY OIL STEAM PILOT - AOSTRA, Canadian Occidental, Esso, 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 multicyclic 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 - Feb/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 FR 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 totalling $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)

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R & D PROJECTS (Continued)

RAPAD BITUMEN UPGRADING PROJECT – Research Association for Petroleum Alternatives Development and Ministry of International Trade and Industry (T-550)

The Research Association for Petroleum Alternatives Development (RAPAD), supported by the Japanese Ministry of International Trade and Industry, adopted bitumen upgrading as one of its major research objectives in 1980. Three approaches were investigated: thermal cracking-hydrotreating, thermal cracking-solvent deasphalting-hydrotreating, and catalytic hydrotreating.

A pilot plant of the series of hydrotreating, i.e., visbreaking-demetallation-cracking, was completed in 1984. Its capacity is 5 barrels per day, and operation has been used to evaluate catalyst performance and also to obtain engineering data. Hydroconversion catalysts with high activities for middle distillates productivity, coke suppression, and for demetallation have been developed. These catalysts made it possible to produce synthetic crude oil of high quality from tar sands bitumen under mild reaction conditions, which results in lower hydrogen consumption. Research with the 5 barrel per day pilot plant was finished in 1988. A 10 barrels per day pilot plant with suspended-bed reactor, designed by the M. W. Kellogg Company, was completed in 1985. A new type catalyst for the suspended bed process has been developed, and data have been obtained for process scaleup.

The original RAPAD program was an 8-year program, concluded in March 1988 at a total cost of 23.9 billion yen. Some additional research and development has been continued since April 1988.

The process developed with the aid of the 10 barrel per day pilot plant is called the MRH process (mild resid hydrocracking process). It is a suspended-bed process which hydrocracks, demetallizes and converts heavy oil such as vacuum resid or oil sand bitumen to middle distillates at a relatively low pressure (60-80 kilograms per square centimeter).

Project Cost: 23.9 billion yen through 1988

SANDALTA – Gulf Canada Corp., Home Oil Company Ltd., and Mobil Oil Canada Ltd. (T-580)

Home Oil Company Limited, in October 1979, announced the farouout of its Athabasca oil sands property to Gulf Canada Corp. The property, Oil Sands Lease #0980090001 (formerly BSL #30) consists of 15,086 hectares (37,715 acres), situated 43 kilometers (26 miles) north of Fort McMurray on the east side of the Athabasca River. Under terms of the farout agreement, Gulf, through expenditures totalling some $42 million, can earn up to an 83.75 percent interest in the lease with Home retaining 10 percent and Mobil Canada Ltd. 6.25 percent. An exploratory drilling program was carried out in the 1980 and 1981 drilling seasons, and in 1985. Engineering studies on commercial feasibility were continuing.

Little progress has been reported since 1987.

Project Cost: Not Specified

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
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

TACIUK PROCESSOR PILOT – AOSTRA and The UMA Group Ltd. (T-510)

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 and tailinge. 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.

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 1991 or 1992. (See Stuart Oil Shale Project in oil shale status section).

A third area of application of the technology has been developed in the past five 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 is presently treating PCB contaminated soil to remove the PCB contaminant. The removal treatment is by chemical dechlorination within the ATP unit and must meet standards of 2 ppm or less PCB for the remediated soil.

In February 1991, AOSTRA commissioned the construction of a 5 ton per hour portable unit for use in Alberta. It was to be available in the fall of 1991 to demonstrate oil production cleanup of oily waste sites in Alberta and western Canada.

Project Cost To Date: C$19 million (AOSTRA)

TANGLEFLAGS NORTH – Sceptre Resources Limited and Murphy Oil Company 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 are providing up to $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.

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 the first quarter of 1991 was 812,000 barrels.

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STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

Project Cost: $10.2 million by 1990

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.

The project has been put on temporary hold.

Project Cost: Unknown

TUCKER LAKE PILOT PROJECT - Husky Oil, Ltd. (T-640)

Husky began operating a cyclic-steam pilot project at Tucker Lake in February 1984. The location of Husky's 18,000 acre lease is approximately three miles southwest of Esso's Cold Lake project. Four wells were initially put into operation and seven wells were added during 1985. To determine the most productive area the test wells were widely spaced over a 3,000 acre section of the lease.

Preliminary estimates indicate that oil in place at the project area exceeds 680 million barrels. Production is from the unconsolidated Clearwater sand with a pay zone of 110 feet at a depth of 1,500 feet. Porosity of the formation is 33 percent and permeability is 1,500 md. Oil gravity is 10 degrees API with a viscosity of 100,000 cp at reservoir temperatures of 60 degrees F.

Husky has developed a 13 well pad which includes a 50 million BTU per hour steam generator along with other associated facilities. The project resumed operation during the third quarter of 1987 following a 12-month shutdown due to inadequate oil prices.

The project was mothballed again in the fourth quarter of 1988 due to low oil prices. There are currently no plans or schedule for a renewal of operations.

Project Cost: Not Disclosed

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. (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 500 meters and
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since September 1991)

R & D PROJECTS (Continued)

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.

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$11 per barrel, which would be less costly than most current in situ bitumen production.

In 1991, Chevron announced it would construct a $53 million pilot plant using the HASDrive process on a recently acquired oil sands lease about 50 kilometers northeast of Fort McMurray, Alberta.

Project Cost: $150 million
# COMPLETED AND SUSPENDED PROJECTS

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In September 1991 the United States Department of Energy (DOE) selected the Wabash River Coal Gasification Repowering Project for funding under Round 4 of DOE's Clean Coal Technology Program. The project will demonstrate, in a commercial setting, coal gasification repowering of an existing generating unit affected by the 1990 Clean Air Act Amendments (CAAA).

The Wabash River project, a joint venture of Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana, will design, construct, own, and operate a coal gasification combined cycle (CGCC) power plant. Coal gasification technology will be used to repower one of six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The CGCC power plant will produce 265 net megawatts of electrical power. The project will use locally mined, high sulfur coal.


Coal

PSI will procure coal for Destec's coal gasification facility which will be designed to accept coal with a maximum sulfur content of 5.9 percent (dry basis) and a minimum energy content of 13,500 BTU per pound (moisture and ash free basis). PSI and Destec will also test at least two other coals for significant periods during the 3-year demonstration period.

Project Team

PSI will manage the construction of, own and operate the power generation facilities. Destec will manage the construction of, own and operate the coal gasification facilities. The Electric Power Research Institute will provide performance analysis of the project and act as a resource to the joint venture.

PSI and Destec have signed a Gasification Services Agreement that outlines the commercial terms under which the project will be developed and operated for a minimum of 20 years.

Project Technical Description

Coal is ground with water to form a slurry. It is then pumped into a gasification vessel where oxygen is added to form a hot, raw gas through partial combustion. Most of the non-carbon material in the coal melts and flows out the bottom of the vessel forming slag. The hot, raw gas is then cooled in a heat exchanger to generate high pressure steam. Particulates, sulfur and other impurities are removed from the gas before combustion to make it an acceptable fuel for the gas turbine.

The synthetic fuel gas (syngas) is piped to a combustion turbine generator which produces approximately 198 megawatts of electricity. A heat recovery steam generator recovers gas turbine exhaust heat to produce high pressure steam. This steam and the steam generated in the gasification process supply an existing steam turbine-generator in PSI's plant to produce an additional 104 megawatts. Plant auxiliaries consume approximately 37 megawatts, for a nominal net power generation export of 265 megawatts. The projected net plant heat rate for the entire new and repowered units is 8,740 BTU per kilowatt-hour, representing more than a 20 percent improvement over the existing unit.

A block flow diagram of the process is shown in Figure 1.

The joint venture has chosen to incorporate novel technology in the project. According to the authors, the incorporation of novel technology will enable utilities to make rational commercial decisions concerning the utilization of Destec's technology, especially in a repowering application.

New enhancements, techniques and other improvements included in the novel technology envelope for the project are as follows:

- A novel application of integrated coal gasification combined cycle technology will be demonstrated—repowering an existing coal fired power generating unit.

- The coal feed will be high sulfur bituminous coal, thus demonstrating the environmental performance and energy efficiency of Destec's advanced two-stage coal gasification process.

- Hot/dry particulate removal/recycle will be demonstrated at full commercial scale at the project.

Other coal gasification process enhancements included in the project to improve the efficiency and environmental characteristics of the system are as follows:

- Syngas recycle will provide fuel and process flexibility while maintaining high efficiency.
A high pressure boiler will cool the hot raw gas by producing steam at a pressure of 1,600 psia.

The carbonyl sulfide hydrolysis system to be incorporated at the project will be the first application of this technology to any coal gasification combined cycle system.

The slag fines recycle system will recover most of the carbon present in the slag byproduct stream and recycle it back for enhanced carbon conversion, which also results in a high quality byproduct slag.

Fuel gas moisturization will be accomplished by the use of low-level heat in a new concept that reduces steam injection required for NOx control.

A novel sour water system will be used to allow more complete recycle of this stream, reducing waste water and increasing efficiency.

An advanced design oxygen plant producing 95 percent pure oxygen will be used to increase the overall efficiency of the project by lowering the power required for production of oxygen.

The power generation facilities included in the project will incorporate the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the existing Unit 1 steam turbine.

The project will incorporate an advanced gas turbine with new design compressor and turbine stages, higher firing temperatures and higher pressure ratios.

Integration between the heat recovery steam generator (HRSG) and the gasification facility has been optimized to yield higher efficiency and lower operating costs.

Repowering of the existing steam turbine will involve upgrading the unit in order to accept increased steam flows generated by the HRSG, thus maximizing the cycle efficiency.
Environmental Aspects

The plant will be designed to substantially out-perform the standards established in the CAAA for the year 2000. The technology employed will remove at least 98 percent of the sulfur in the coal. SO$_2$ emissions will be less than 0.20 pounds of SO$_2$ per million BTU of fuel. NO$_x$ emissions from the project have not been defined but will meet anticipated limits set by state and federal regulators. On a per kilowatt-hour basis, CO$_2$ will be reduced, as well, because the repowered unit will be substantially more efficient than the other generating stations. Table 1 compares current emissions of the Wabash Unit 1 with emissions from the project after the coal gasification repowering.

The gasification process byproducts, sulfur and slag, are also recyclable. Most of the non-carbon minerals in the coal are removed during the gasification process. Sulfur is removed as 99.7 percent pure elemental sulfur and can be sold as a raw material to make agricultural fertilizer. The remaining minerals leave the process as slag which has been used as aggregate in asphalt roads and as structural fill in various types of construction applications.

Project Schedule

Cycle optimization studies, activities supporting environmental permits and preliminary geotechnical investigations took place through the summer of 1991. Milestones to be completed in 1991 include finalization of the process design and the filing of a petition with the Indiana Utility Regulatory Commission for approval of the project.

Activities in 1992 will include negotiation of the Cooperative Agreement with the DOE, detailed engineering of the facilities, major equipment procurement and, depending on permits and approvals, beginning of construction.

Detailed engineering will be complete in 1993 and operations personnel will be selected and trained beginning in 1994. Commercial operations will commence in 1995.

*****

CTC TO TEST CHAR IN ELECTRIC ARC FURNACE

Coal Technology Corporation (CTC) of Bristol, Virginia will be making experimental test runs late this year using char for steel making in a full scale electric arc furnace. The char will come from CTC's continuous mild gasification unit (CMGU) which has been under development for several years.

Construction of the 1,000 pound per hour CMGU was completed in February 1991, and at least 30 shakedown runs have been made. The process is designed to convert highly caking bituminous coals into a char which can be upgraded to blast furnace coke, and liquids which can be fractionated and blended with petroleum based motor fuels.

Process Description

In the CTC continuous mild gasification process, as-received coal is dried, ground to minus 0.25 inch size and charged to a feed hopper. A screw feeder is used to meter the ground coal from the feed hopper into the pyrolysis reactor.

The reactor consists of a pair of interfolded screws which convey the feed coal through an enclosed, heated shell. Radiant gas burners, located beneath the shell and inside the hollow screws, heat the walls and screw surfaces to controlled temperatures up to 1,400°F. The interfolded screws carry the feed coal through the pyrolysis reactor in a back and forth motion which prevents the hot plastic coal from sticking and

TABLE 1

<table>
<thead>
<tr>
<th>Project Emissions</th>
<th>SO$_2$</th>
<th>NO$_x$</th>
<th>CO</th>
<th>PM</th>
<th>PM-10</th>
<th>VOC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasification Block Tons/yr</td>
<td>1,595</td>
<td>40</td>
<td>13</td>
<td>25</td>
<td>13</td>
<td>5</td>
</tr>
<tr>
<td>Power Block Tons/yr</td>
<td>1,253</td>
<td>774</td>
<td>788</td>
<td>115</td>
<td>99</td>
<td>70</td>
</tr>
<tr>
<td>Total Tons/yr</td>
<td>2,848</td>
<td>814</td>
<td>801</td>
<td>140</td>
<td>112</td>
<td>75</td>
</tr>
<tr>
<td>Lb/MW hr</td>
<td>2.4</td>
<td>0.7</td>
<td>0.7</td>
<td>0.1</td>
<td>0.1</td>
<td>0.06</td>
</tr>
</tbody>
</table>

Current Unit No.1

<table>
<thead>
<tr>
<th>Boiler Emissions</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Tons/yr</td>
<td>5,628</td>
<td>1,370</td>
<td>94</td>
<td>126</td>
<td>126</td>
<td>5</td>
</tr>
<tr>
<td>Lb/MW hr</td>
<td>38.2</td>
<td>9.3</td>
<td>6.0</td>
<td>85.0</td>
<td>85.0</td>
<td>0.03</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, DECEMBER 1991
jamming the screws. Volatile matter is removed from the pyrolysis reactor and cooled in external condensers.

The hot char from the pyrolysis reactor is cooled by indirect heat exchange in a water cooled screw conveyor, after which it is mixed with binders and formed into green coke briquettes. The gases driven from the green coke briquettes are burned to heat both the pyrolysis reactor and the feed coal drier.

Figure 1 is a simplified drawing showing the general arrangement and main components of the CTC twin screw pyrolysis reactor. Coal enters the reactor through the coal feeder (1) which is a conventional single screw conveyor. A 25 horsepower hydraulic motor (2) drives timing gears (3) which in turn drive the twin screws (4), usually at a preselected speed of approximately 17 revolutions per minute. Each screw is 15.75 inches outside diameter by 16 feet long built on a 10-inch diameter hollow shaft. The screws are inside the screw housing (5) which is contained in an insulated furnace (6) heated by radiant gas burners (7). The gas heaters have an air blower for primary combustion air for the gas heaters (not shown) and a secondary air fan (8). The products of combustion from the gas burners are discharged to a stack through a vent (9).

The reactor is maintained at an internal pressure a few inches of water higher than atmospheric pressure. The volatile matter released from the coal passes from the reactor through three vents (10) to condensers. The char product is discharged to the char cooler (11). The reactor is equipped with inspection ports (12) which can be opened for inspection only when the reactor is not operating.

In typical operation, the interfolded twin screws are operated for 60 seconds in the forward direction, and then after a pause, 15 seconds in the reverse direction. The time ratio of forward/reverse motion is adjustable, depending on the coal feed rate, the desired residence time of the coal/char in the reactor, the temperature of the furnace, and the desired final volatile matter content of the char. It is also possible to vary the rotational speed of the screws.

Initial Operations

Tests runs have been made with seven different caking bituminous coals which are listed in Table 1. These Eastern

---

![Figure 1: Cross Section of Pyrolysis Reactor](source: CTC)
TABLE 1
COALS USED IN INITIAL OPERATIONS

<table>
<thead>
<tr>
<th>Name of Coal</th>
<th>Seams</th>
<th>% Volatile</th>
<th>% Ash</th>
<th>% Sulfur</th>
<th>% Moisture</th>
<th>BTU/lb</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ramsey #5</td>
<td>Dorchester/</td>
<td>31.43</td>
<td>6.95</td>
<td>1.18</td>
<td>8.37</td>
<td>13,000</td>
</tr>
<tr>
<td></td>
<td>Clintwood</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Esserville #2</td>
<td>Raven/Tiller/</td>
<td>30.63</td>
<td>6.21</td>
<td>0.76</td>
<td>4.12</td>
<td>14,016</td>
</tr>
<tr>
<td></td>
<td>Clintwood</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>VICC #1</td>
<td>Jawbone/Alice/</td>
<td>31.41</td>
<td>8.94</td>
<td>1.04</td>
<td>6.0</td>
<td>13,000</td>
</tr>
<tr>
<td></td>
<td>Clintwood</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Splash Dam</td>
<td>Splash Dam</td>
<td>28.60</td>
<td>6.84</td>
<td>0.84</td>
<td>6.8</td>
<td>13,760</td>
</tr>
<tr>
<td>Lower Phillips</td>
<td>Lower Phillips</td>
<td>40.41</td>
<td>3.43</td>
<td>0.55</td>
<td>1.6</td>
<td>14,801</td>
</tr>
<tr>
<td>Pocahontas</td>
<td>Pocahontas</td>
<td>11.18</td>
<td>5.15</td>
<td>0.75</td>
<td>1.89</td>
<td>14,880</td>
</tr>
<tr>
<td>Knox Creek</td>
<td>Knox Creek</td>
<td>30.85</td>
<td>6.19</td>
<td>0.84</td>
<td>8.36</td>
<td>14,547</td>
</tr>
</tbody>
</table>

Coals all performed satisfactorily in the reactor, and no major differences in coke making were observed. The sulfur content and ash content are consistent with industry preferences in steel making coke.

A sieve analysis of feed coal and char product are compared in Table 2. The data reflect an increase in average particle size attributable to agglomeration as the coal passes through the plastic stage.

Data from recent successful test runs show that the volatile matter of the char product was less than 10 weight percent, a level which appears to be satisfactory for coke making. The bulk temperature of the char is believed to be close to 1,000°F.

TABLE 2
CMGU SIEVE ANALYSIS

<table>
<thead>
<tr>
<th>Product, Sieve Mesh</th>
<th>Feed Coal, %</th>
<th>Char, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>+6</td>
<td>3.3</td>
<td>12.5</td>
</tr>
<tr>
<td>-6, +16</td>
<td>15.0</td>
<td>31.8</td>
</tr>
<tr>
<td>-16, +60</td>
<td>33.4</td>
<td>35.4</td>
</tr>
<tr>
<td>-60, +200</td>
<td>43.9</td>
<td>18.0</td>
</tr>
<tr>
<td>-200</td>
<td>4.2</td>
<td>2.3</td>
</tr>
<tr>
<td>Totals</td>
<td>99.8</td>
<td>100.0</td>
</tr>
</tbody>
</table>

Bench Scale Char Upgrading

Recent work in char upgrading has been focused on making formcoking from char that meets industry standards and can be produced profitably on a commercial scale. A large part of the coking study has been the testing of binders such as coal tar pitch, or the tar fraction from CMGU. A total of 120 formulations have been tested; typical formations contain from 75 to 85 weight percent char, and from 25 to 15 weight percent binders and additives.

CTC has been successful in making formcoking that meets the Japanese reactivity test and the strength after reaction test. There appears to be no large differences between char from the CMGU and the batch mild gasification retorts when converted to formcoking.

Alternate Uses for Char

Recent work has been directed toward converting char to metallurgical coke for the steel industry. Late this year some experimental tests of char for steel making in a full scale electric arc furnace will be made. In the past, anthracite has been used in electric steel making to reduce power consumption and decrease the melt time.

Char from the continuous mild gasification process has about the same fixed carbon, volatile matter and ash content as anthracite. CTC says that char may even be better in an electric furnace because of the greater reactivity of char. If the electric furnace tests are successful, another market for char could be expected at the rate of 30 pounds of char per ton of steel.

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SYNTHETIC FUELS REPORT, DECEMBER 1991
ENCOAL ON SCHEDULE FOR STARTUP IN FIRST HALF OF 1992

A status report on the design and construction of the ENCOAL mild gasification plant near Gillette, Wyoming was presented at the Gasification Contractors Review Meeting held in Morgantown, West Virginia in August. The project is a demonstration of the liquids from coal (LFC) process developed by SGI International.

In September 1990, ENCOAL and the United States Department of Energy (DOE) signed a Cooperative Agreement under Round 3 of the Clean Coal Technology Program which allowed ENCOAL to proceed with the design and construction of a mild gasification plant to process 1,000 tons of coal per day. The Triton Coal Company's Buckskin Mine near Gillette is the host location.

Using LFC technology, the plant will process subbituminous Powder River Basin coal and produce two environmentally superior products. The solid product, called process derived fuel (PDF) is a stable, high-BTU fuel similar in composition and handling properties to Eastern bituminous coals but very low in sulfur. Coproduced with PDF is a coal derived liquid (CDL) that is similar in properties to a low sulfur No. 6 fuel oil.

A complete description of this process is provided in the Pace Synthetic Fuels Report, March 1991, beginning on page 4-13.

Project Description

A significant reduction in work scope and cost is being realized due to the existence of the host Buckskin Mine. Coal storage and handling facilities, rail loadout, access roads, utilities, office, warehouse and shop facilities were all present at the mine site and significantly reduced the need for new facilities for the project.

The project schedule is provided in Figure 1. Engineering, procurement and construction management for the project is being handled by The M.W. Kellogg Company.

The major equipment items for the project are listed in Table 1. Table 2 lists the major subcontract packages anticipated for the project. (Both tables are on the next page.) About 150,000 man-hours are estimated to complete the construction phase. Mechanical completion is projected for early 1992.

ENCOAL and Triton are handling the operations planning, training, maintenance planning, staffing, plant precommissioning and startup, data gathering and plant operation. All permitting requirements are being handled by ENCOAL.

The ENCOAL project will demonstrate the integrated operation of several process steps:

- Coal drying on a rotary grate using convective heating
- Coal devolatilization on a rotary grate using convective heating
- Hot particulate removal with cyclones
- Integral solids cooling and deactivation/pasivation
- Combustors operating on low-BTU gas from internal streams
- Solids stabilization for storage and shipment

![FIGURE 1](image_url)

ENCOAL PROJECT SCHEDULE
TABLE 1
ENCOAL MAJOR EQUIPMENT

<table>
<thead>
<tr>
<th>Item</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mild Gasification Process</td>
<td></td>
</tr>
<tr>
<td>Dryer</td>
<td>Partial</td>
</tr>
<tr>
<td>Dryer Cyclone</td>
<td>9/11</td>
</tr>
<tr>
<td>Dryer Blower</td>
<td>8/26</td>
</tr>
<tr>
<td>Flue Gas Desulfurization Unit</td>
<td>8/19</td>
</tr>
<tr>
<td>Dryer Combustor</td>
<td>9/13</td>
</tr>
<tr>
<td>Pyrolyzer</td>
<td>Partial</td>
</tr>
<tr>
<td>Pyrolyzer Cyclone</td>
<td>10/1</td>
</tr>
<tr>
<td>PDF Cooler</td>
<td>In Place</td>
</tr>
<tr>
<td>Quench Oil Chamber</td>
<td>In Place</td>
</tr>
<tr>
<td>Electrostatic Precipitators</td>
<td>1 of 3 on site</td>
</tr>
<tr>
<td>Pyrolyzer Blower</td>
<td>8/19</td>
</tr>
<tr>
<td>Pyrolyzer Combustor</td>
<td>9/13</td>
</tr>
<tr>
<td>Structural Steel</td>
<td>On schedule</td>
</tr>
</tbody>
</table>

Off-Sites Facilities and Utilities
- Feed Coal Silo: Complete
- Screen: On site
- PDF Silo: Complete
- CDL Storage Tanks: 11/3
- Fines Bin: On site
- Conveyors: 8/15
- Standby Generator: 10/1
- Steam Boiler: 8/26
- Nitrogen System: 9/26
- Air Compressor: 9/9
- Sodium Carbonate System: 8/15

TABLE 2
ENCOAL PROJECT
MAJOR SUBCONTRACTS

<table>
<thead>
<tr>
<th>Work Scope</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mechanical Erection</td>
<td>Mobilized</td>
</tr>
<tr>
<td>Electrical &amp; Instruments</td>
<td>Mobilized</td>
</tr>
<tr>
<td>Silos</td>
<td>Complete</td>
</tr>
<tr>
<td>Earthwork</td>
<td>Mobilized</td>
</tr>
<tr>
<td>Underground Piping</td>
<td>Mobilized</td>
</tr>
<tr>
<td>Foundations/Floors/Piping</td>
<td>Complete</td>
</tr>
<tr>
<td>Architectural Buildings</td>
<td>Mobilized</td>
</tr>
<tr>
<td>Off-Sites Concrete</td>
<td>Mobilized</td>
</tr>
<tr>
<td>Mat Foundations</td>
<td>Complete</td>
</tr>
</tbody>
</table>

- Computer control and optimization of a mild coal gasification process

Project Status

A formal ground breaking ceremony was held in October 1990 at the time field construction began. By the end of 1990, the PDF plant and screening building foundations were complete and one 12,000 ton storage silo had been slipped. Contracts for the feed coal silo and PDF product silo were also awarded. An order had been placed for the structural steel and all mill run steel requirements were released for fabrication.

In early 1991, Kellogg’s engineering task force developed the requisitions for the major mechanical erection package and most of the engineered equipment, including all of the items in Table 1.

Minor revisions to ENCOAL’s Wyoming air permit were necessitated due to some process modifications. These included changes in the stack diameter and height, composition of the feed coal, operating parameters and scrubber efficiencies. The changes were submitted to the Department of Environmental Quality in April and approved by July 1991.

Applications for a non-discharging sludge disposal pond for the FGD (flue gas desulfurization) were submitted to the appropriate agencies and approvals have been received. A permit revision for an existing sedimentation pond that ENCOAL plans to use as a source of cooling water was also requested. All of these applications have now been approved, at least verbally.

Kellogg completed their detailed design in mid July 1991. All materials and equipment that are to be designed and procured by Kellogg have been committed. Bid packages have been prepared for all of the major field subcontracts. In parallel with the early design work, the project management plan and all supporting documents were completed and approved by DOE. The environmental monitoring plan was submitted to DOE in November 1990. Comments and responses have been traded and the document will be finalized when all of the permit conditions are received. The NEPA (National Environmental Policy Act) process was completed in October, shortly after award largely due to the joint efforts of DOE and ENCOAL in the pre-award period.

A HazOp review was conducted by Kellogg and ENCOAL in March 1991. Included on the review team were members of the design team as well as "outsiders" not associated with the project but knowledgeable in similar plant operations. There were no significant or costly oversights uncovered by the review.

All major subcontracts have now been awarded and the contractors have mobilized in the field. As shown in Table 2,
several contracts have been completed. Construction is on schedule for a first quarter 1992 startup.

Triton Coal Company, the site host, has been contracted through a services agreement to operate the ENCOAL plant facilities. They have now selected all of their operating staff, including the plant manager and plant engineer.

Future Work

By the end of February 1992, ENCOAL expects to complete the construction of the mild gasification plant, off-sites and utilities. Pre-commissioning activities will begin as each plant system is completed. Plant startup and testing should take place in the first half of 1992. During 1992 PDF and CDL will be delivered to customers with commercial potential and test burns conducted in their facilities.

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PRELIMINARY DESIGN FOR COMBUSTION ENGINEERING IGCC PROJECT TO BE FINISHED NEXT YEAR

Combustion Engineering, Inc. (C-E) of Windsor, Connecticut is participating in a $270 million coal gasification combined cycle repowering project that will provide 65 megawatts of electrical power to City Water, Light & Power (CWL&P) in Springfield, Illinois.

The project, selected under Round 2 of the United States Department of Energy's (DOE) Clean Coal Technology Program, is in the preliminary design phase which is scheduled to be completed in 1992. The project schedule, budget and milestones are shown in Figure 1. DOE has agreed to fund 48 percent of the project's cost.

Project Description

The C-E project will demonstrate integrated gasification combined cycle (IGCC) technology in a commercial application by repowering an existing CWL&P plant in Springfield. The project duration will be 126 months, including a 63-month demonstration period.

---

FIGURE 1

C-E PROJECT SCHEDULE

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Quarter</td>
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<td>2</td>
<td>3</td>
<td>4</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>4</td>
</tr>
</tbody>
</table>

Phase I - Preliminary and Design
Phase IA - Definition and Permitting
Phase IB - Preliminary Design
Phase IC - Detail Design
Phase II - Construction, Installation and Startup
Phase III - Operation and Demonstratisation

BUDGET (in $M)

<table>
<thead>
<tr>
<th>Period</th>
<th>Phase I</th>
<th>Phase II</th>
<th>Phase III</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Period 1</td>
<td>6.0</td>
<td>7.0</td>
<td>22.3</td>
<td>16.7</td>
</tr>
<tr>
<td>Period 2</td>
<td>6.0</td>
<td>63.8</td>
<td>125.1</td>
<td>125.1</td>
</tr>
<tr>
<td>Period 3</td>
<td>102.5</td>
<td>270.7</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

SOURCE: COMBUSTION ENGINEERING, INC.
The IGCC system will consist of C-E’s air-blown, entrained-flow, two-stage, pressurized coal gasifier; an advanced hot gas cleanup process; a combustion turbine adapted to use low-BTU coal gas; and all necessary coal handling equipment (Figure 2). An existing 25 megawatt steam turbine at CWL&P’s Lakeside Station will also be part of the IGCC system.

The result of repowering will be an IGCC power plant with low environmental emissions and high net plant efficiency. The repowering will increase plant efficiency. The repowering will increase plant output by 40 megawatts through addition of the combustion turbine, thus providing a total IGCC capacity of 65 megawatts.

The IGCC will include C-E’s slagging, entrained-flow, gasifier operating in a pressurized mode and using air as the oxidant. The hot gas will be cleaned of particulate matter (char) which is recycled back to the gasifier. After particulate removal, the product gas will be cleaned of sulfur and then burned in a gas turbine.

The proposed project includes design and demonstration of two advanced hot gas cleanup processes. The primary sulfur removal method features a moving-bed zinc ferrite system downstream of the gasifier. C-E intends to use the General Electric (GE) moving-bed, zinc ferrite sulfur removal system currently being piloted by GE Environmental Systems, Inc. A second complementary process is in situ desulfurization achieved by adding limestone or dolomite directly to the coal feed or gasifier bed.

In this plant, the gasifier will be producing a low-BTU gas (LBG), which will be used as fuel in a standard GE gas turbine to produce power. This gas turbine will have the capability to fire LBG and natural gas (for startup). Because firing LBG uses less air than natural gas, the gas turbine air compressor will have extra capacity. This extra compressed air will be used to pressurize the gasifier and supply the air needed in the gasification process.

The plant is made of three major blocks of equipment. They are the fuel gas island which includes the gasifier and gas cleanup, the gas turbine power block, and the steam turbine block which includes the steam turbine and the heat recovery steam generator (HRSG).

Table 1 shows the planned project performance.

![FIGURE 2](source: combustion engineering, inc.)
TABLE 1
C-E PROJECT PERFORMANCE SUMMARY

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Design Cases</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Nominal</td>
</tr>
<tr>
<td>Coal to Gasifier (TPD)</td>
<td>600</td>
</tr>
<tr>
<td>Combustion Turbine Power (MWe)</td>
<td>40</td>
</tr>
<tr>
<td>Steam Turbine Power (MWe)</td>
<td>25</td>
</tr>
<tr>
<td>In-Plant Use (MWe)</td>
<td>5</td>
</tr>
<tr>
<td>Net Power (MWe)</td>
<td>60</td>
</tr>
<tr>
<td>Heat Rate (BTU/kW)</td>
<td>8,690</td>
</tr>
</tbody>
</table>

As major equipment sections are completed, they will be individually started up and brought online to produce power. The gas turbine equipment will have the shortest lead time so this equipment will be installed, checked out, and brought into commercial service first. Initially, the gas turbine will be fired on natural gas operating as a simple cycle gas turbine electric generator.

The existing steam turbine will be refurbished and the HRSG will be brought online next. The operation of the equipment will make the plant a combined cycle fired on natural gas. All of this equipment will be checked out and operated prior to the startup of the gasification plant.

The last major block of equipment will be the fuel gas island including the gasifier and gas cleanup equipment. When this equipment is put into operation, the plant will be a fully integrated coal gasification combined cycle plant.

C-E Gasification Process

Using the C-E gasification process, it is possible to achieve net plant heat rates of better than 8,000 BTU per kilowatt-hour.

The process produces non-leachable fused ash which can be disposed of in an environmentally acceptable manner without requiring any additional processing. The elemental sulfur produced from the C-E process minimizes the land area necessary for disposal. The low-BTU gas produced in the process produces lower NOx compared to medium-BTU gas or natural gas when burned in the gas turbines.

In the gasification process, some of the coal and all of the char is fed to the combustor section, while the remaining coal is fed to the reductor section of the gasifier. The coal and char in the combustor is mixed with air and the fuel-rich mixture is burned creating the high temperature necessary to gasify the coal and to melt the mineral matter in the coal.

The slag flows through a slag tap at the bottom of the combustor into a water-filled slag tank where it is quenched and transformed into an inert, glassy, granular material.

The hot gas leaving the combustor enters the second stage called the reductor. In the reductor, char gasification occurs along the length of the reductor zone until the temperature falls to a point where the gasification kinetics become too slow. Then the gases are cooled with convective surface to a temperature low enough to enter the cleanup system. Thus, nearly all of the liberated energy from the coal that does not go into producing fuel gas is collected and recovered with steam generating surface either in the walls of the vessel or by conventional boiler convective surfaces in the backpass of the gasifier.

Char carried out of the gasifier with the product gas stream is collected and recycled back to the gasifier where it is completely consumed. Thus, there is no net production of char which results in negligible carbon loss.

The product gas then enters a desulfurization system where it is cleaned of any sulfur compounds present in the fuel gas. The clean fuel gas is now available for use in the gas turbine combustor for a combined cycle application.

According to the company, C-E's gasifier is well suited for scaleup to the sizes required to achieve economy of scale in large power plants. A single gasifier will be capable of gasifying up to 5,000 tons of coal per day. In addition, all types of coal can be processed without special pretreatment.

MTCI INDIRECT GASIFIER YIELDS HIGH HYDROGEN CONCENTRATION

Since 1989, Manufacturing and Technology Conversion International, Inc. (MTCI) has been engaged in a project aimed at providing cost effective hydrogen production from raw coal, mild gasification char, or ash residues by an indirect gasification process.

The MTcI approach involves the use of an indirectly heated gasifier which has the potential to overcome the limitations of both the oxygen-blown partial oxidation systems and the two-stage circulating solids systems. An overview of the project results was presented at the Gasification Contractors Review Meeting held in Morgantown, West Virginia in August.

In the MTcI process, coal is fed to a fluidized bed vessel and reacted with steam to generate a hydrogen-rich product gas. Endothermic heat for the gasification reaction is supplied indirectly through heat transfer surfaces immersed within the fluid bed. The heat source is derived from the combustion
of a portion of the feedstock char or treated gasifier product gas.

This combustion is accomplished in a naturally pulsating combustor which also is the immersed heat exchange system. These pulsations translate to improved heat transfer rates within the fluid bed. This concept results in a simplified design for processing the coal into a high quality synthesis gas for hydrogen production.

Char and Ash Concentrate Gasification

Two successful tests for char gasification were performed under the conditions summarized in Table 1. The char feed material for these tests was produced by mild gasification.

Two tests were conducted for gasification of Southern Clean Fuels' Wilsonville Coal Liquefaction Ash Concentrates (SRC Residue) obtained by direct coal liquefaction. The test summary is also listed in Table 1. The results show that the limestone bed material does promote gasification. Under the same conditions, the hydrogen gas production rate of a limestone bed gasifier is almost twice that of a silica sand bed gasifier.

Gasification of Low Rank Coals

A long duration mild gasification test and a short duration direct gasification test were conducted for Black Thunder Coal. The results of the mild gasification test are shown in Table 2 on the next page.

Comparing the results from the direct gasification test at 1,390°F (Table 2), the coal gasification yields a much higher gas production rate for similar feed rates and gasification temperatures than ash concentrates. This is because of the higher reactivity of coal. In a real hydrogen production unit, the ash concentrate may be blended with coal for a reasonable hydrogen yield.

Four lignite gasification tests were conducted under a Small Business Innovation Research project. The test conditions and results are also listed in Table 2.

Observations and Results

In all the tests, a high carbon gasification efficiency (gasified/feed carbon) was achieved. Additionally, in all the tests, except the mild gasification run, very little tar/oil was produced.

The tests demonstrated that the MTI indirect gasification technology has a high hydrogen gas yield. The raw dry gas product contained 52 to 66 volume percent hydrogen which was much higher than from other techniques. For example, tests from the University of North Dakota showed only 45 percent hydrogen in the product gas. The MTI synthesis gas with high hydrogen concentration would, therefore, require less effort during the water gas shift reaction for the production of hydrogen.

The main parameter affecting the steam reforming process is the hydrogen yield based on feed carbon. On the average,

TABLE 1

PRODUCT GAS ANALYSIS
(From Char and Liquefaction Ash Concentrate)

<table>
<thead>
<tr>
<th>Feed Material</th>
<th>Char Ash Conc.</th>
<th>Ash Conc.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bed Material</td>
<td>Limestone</td>
<td>Sand</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>1,456</td>
<td>1,467</td>
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<tr>
<td>Feed Rate (lb/hr)</td>
<td>24</td>
<td>24</td>
</tr>
<tr>
<td>Steam In (lb/hr)</td>
<td>53.5</td>
<td>30.5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Product Gas (Vol%)</th>
<th>Char Ash Conc.</th>
<th>Ash Conc.</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂</td>
<td>53.32</td>
<td>56.93</td>
</tr>
<tr>
<td>CO</td>
<td>21.69</td>
<td>17.37</td>
</tr>
<tr>
<td>CO₂</td>
<td>23.67</td>
<td>23.95</td>
</tr>
<tr>
<td>CH₄</td>
<td>1.28</td>
<td>1.54</td>
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<tr>
<td>CH₃</td>
<td></td>
<td>0.13</td>
</tr>
<tr>
<td>C₂H₄</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>C₃H₆</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>C₄⁺</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>H₂S</td>
<td>0.04</td>
<td>0.09</td>
</tr>
<tr>
<td>Gas Product (lb/hr)</td>
<td>52.95</td>
<td>57.11</td>
</tr>
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</table>

SYNTHETIC FUELS REPORT, DECEMBER 1991
TABLE 2

<table>
<thead>
<tr>
<th>Feed Material</th>
<th>Lignite</th>
<th>Lignite</th>
<th>Lignite</th>
<th>Lignite</th>
<th>Coal</th>
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</thead>
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<tr>
<td>Bed Material</td>
<td>Limestone</td>
<td>Limestone</td>
<td>Sand</td>
<td>Sand</td>
<td>Limestone</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>1,430</td>
<td>1,370</td>
<td>1,310</td>
<td>1,430</td>
<td>1,390</td>
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<tr>
<td>Feed Rate (lb/hr)</td>
<td>14</td>
<td>15.1</td>
<td>8.1</td>
<td>7.3</td>
<td>16.9</td>
</tr>
<tr>
<td>Steam Rate (lb/hr)</td>
<td>28.3</td>
<td>30.6</td>
<td>30.6</td>
<td>28.3</td>
<td>28.3</td>
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Product Analysis

<table>
<thead>
<tr>
<th></th>
<th>H₂</th>
<th>C₂O</th>
<th>CO₂</th>
<th>CH₂</th>
<th>C₂H₄</th>
<th>C₂H₆</th>
<th>C₃</th>
<th>C₄⁺</th>
<th>H₂S</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lignite</td>
<td>52.79</td>
<td>69.38</td>
<td>62.27</td>
<td>62.27</td>
<td>28.39</td>
<td></td>
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<tr>
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<td>3.04</td>
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<tr>
<td>Lignite</td>
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<td>0.26</td>
<td>0.29</td>
<td>0.28</td>
<td>0.32</td>
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<td>0.12</td>
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<td>0.07</td>
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<td></td>
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</tr>
<tr>
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<td>0.04</td>
<td>0.07</td>
<td>0.04</td>
<td>0.05</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lignite</td>
<td>0.04</td>
<td>0.03</td>
<td>0.04</td>
<td>0.02</td>
<td>0.04</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lignite</td>
<td>0.13</td>
<td>0.16</td>
<td>0.34</td>
<td>0.34</td>
<td>0.14</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Lignite</td>
<td>31.30</td>
<td>20.26</td>
<td>16.33</td>
<td>10.96</td>
<td>24.7</td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

The MTCI indirect gasifier is able to produce 0.231 pound of hydrogen per pound of feed carbon. Converted to volume units, it corresponds to 43.8 standard cubic feet of hydrogen per pound of feed carbon. This number is about twice that of the average value of the partial oxidation technique. The average final hydrogen yield, after converting all carbon monoxide to hydrogen, is 52.4 standard cubic feet of hydrogen gas per pound of feed carbon.

The reactor bed temperature also plays an important role in hydrogen production. A lower operation temperature has the advantage of higher primary hydrogen yield and lower carbon monoxide yield. Test results indicate that the lower the reactor temperature, the better the quality of product gas.

Lower temperature favors a higher hydrogen ratio at equilibrium but does not favor the reaction rate. For highly reactive feed materials such as porous char and lignite, a bed temperature of 1,400°F seemed adequate for supporting a high enough gasification rate while achieving high carbon to hydrogen conversion. For low reactivity feed material such as ash concentrate, a higher gasifier temperature around 1,500°F is desired.

The MTCI indirectly heated gasifier was found to have high carbon gasification efficiency and high hydrogen yield. It promises to reduce capital and operating costs by 30 to 40 percent over oxygen-blown gasifiers.

PRODUCTION AT GREAT PLAINS CONTINUING AT HIGH LEVEL

While synthetic natural gas production at the Great Plains Synfuels Plant near Beulah, North Dakota remains at high levels, the company has been plagued by pipeline transportation problems.

In June, the average amount of gas shipped was 148.7 million cubic feet per day. However, Dakota Gasification Company (DGC) vice president K. Janssen told the DGC board that 154.5 million cubic feet per day was billed to the buyers because that amount would have been shipped if the pipeline transportation had been adequate.

Declining natural gas prices, combined with two of the buyers still buying down their high-price contracts, resulted in DGC reporting a $779,000 loss for June. Natural gas production was affected when Northern Border Pipeline restricted the amount of gas that could be shipped because of a compressor being down to replace the gas turbine driver.

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In July, both the production and price of natural gas were nearly the same. According to Janssen, projected operating losses for DGC in the second half of 1991 may not occur. However, pipeline shipments in July were again restricted by both a transportation rate cap and by the reduction imposed during the scheduled compressor station modification. The average daily shipment of syngas in July was 146.8 million standard cubic feet.

The nearly $3 million in profits reported for July came from revenue other than natural gas sales. Sales of ammonia, sulfur and liquid nitrogen continued to provide much of the byproduct revenue. Other byproduct sales included krypton/xenon, tar oil and cresylic acids. More than 350,000 liters of krypton/xenon were shipped in July, while cresylic acid shipments totaled 6,000 gallons.

In order to correct the environmental deficiencies that have existed at the synfuels plant, it is anticipated that a wet limestone scrubbing system will be used to control SO₂ emissions. The capital costs for this system are $100 million with annual operating costs of about $10 million.

TECO ENERGY RELOCATES ROUND 3 IGCC PROJECT

An integrated gasification combined cycle (IGCC) power plant, originally planned for Tallahassee, Florida, has been relocated to a site near Lakeland in Polk County, Florida. The United States Department of Energy (DOE) awarded a $120 million cost share for the project under Round 3 of the Clean Coal Technology Program.

With DOE's approval to relocate the project to Polk County, plans are proceeding for its integration into Tampa Electric Company's planned 220 megawatt expansion project.

TECO Power Services, a TECO Energy subsidiary, recently acquired 100 percent ownership of the project through the purchase of an interest held by CRSS Capital, Inc. Power Services, in cooperation with Tampa Electric, will install the project. Tampa Electric is also a TECO Energy subsidiary.

Tampa Electric's long-term generation plans called for the addition of 220 megawatts of capacity to be installed during the 1995-1996 time frame. The entire project will cost about $400 million. Integration with the DOE project will improve the project's economics as well as improving plant efficiency.

According to a TECO Energy spokesman, the site change will not affect the project's schedule. Phase I, scheduled for completion in 1995, involves the installation of a 150 megawatt combustion turbine. Phase II, to be completed in 1996, calls for the installation of the coal gasification system with hot gas cleanup and combined cycle.

J. Ramil, Tampa Electric's director of power resource planning, said the coal gasification project will not change any requirements for the site itself. Preliminary engineering has been under way for months.

"Instead of pairing two natural gas-fired combustion turbines and one heat recovery steam generator, we are building a gasification system, a combustion turbine and heat recovery steam generator. Also, the entire facility will be more energy efficient," said Ramil.

The coal gasification facility will be about 10 to 12 percent more efficient than a conventional pulverized coal plant. The company expects to achieve a sulfur removal efficiency capability of about 98 percent.

Project Description

In the gasification combined cycle plant (Figure 1, on the next page), coal is first gasified under pressure using a gasification agent (steam with air) to produce fuel gas for subsequent combustion. The fuel is then stripped of its sulfur content prior to combustion.

The facility will include:

- Two air-blown, fixed-bed Lurgi gasifiers
- A General Electric (GE) Environmental Systems moving-bed, hot gas cleanup system
- A GE combustion gas turbine
- A commercially available heat-recovery steam generator (HRSG)
- A GE steam turbine
- Commercially available associated support equipment

In the process, the low-BTU coal gas produced in the Lurgi fixed-bed gasifier goes to a hot gas cleanup subsystem where the removal of sulfur compounds is accomplished in a solid sorbent bed. The cleaned gas is delivered to a combustor which is onboard the gas turbine frame. After producing a portion of the plant's power output, the exhaust gases pass to a steam generation system. The steam which is generated in the heat recovery steam generator is used in a steam turbine power generation subsystem, in the gasifier supply, and supplied as byproduct process steam to a nearby industrial user.

The combined steam and low-BTU gas mixture which enters the hot gas cleanup unit is stripped of hydrogen sulfide through interaction with a counterflowing metal oxide absorption system. The hot coal gas cleanup system consists of a metal oxide H₂S absorber which is continuously regenerated. Zinc ferrite is the specified absorber for the
air-blown IGCC installation. The complete system includes a vessel in which sulfur compounds are removed, a vessel in which to regenerate a sulfided sorbent, a regeneration gas sulfur disposal system, a high-efficiency cyclone to collect entrained particles, and a solids transport system.

Subsequent to the low-BTU gas exiting the hot gas cleanup unit, it is mixed in the combustion cans of the gas turbine with the primary air from the compressor where a combustion product flow stream with a temperature of approximately 1,900 to 2,000°F is generated.

After exiting the combustor, the product gases pass through the expansion turbine of the traditional gas turbine. The exhaust flow from the gas turbine is a temperature of approximately 950 to 1,000°F.

This flow is admitted to the HRSG, where the gas stream temperature is reduced to 250 to 300°F. With the concurrent reduction of temperature of the gas stream, steam is produced at 1,250 psia and 950°F. The steam from the HRSG is then directed to the steam turbine portion of the combined cycle where it expands through a steam turbine to produce electrical power.

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**EASTMAN EXPANDS CHEMICALS FROM COAL**

Eastman Chemical Company has expanded its production of chemicals from with the construction of a $200 million expansion of its facility in Kingsport, Tennessee. The expansion doubles the company's production of methyl acetate, acetic acid and acetic anhydride.

V.H. Agreda, et al., of Eastman Chemical authored a paper discussing the new generation of coal-derived chemicals saying that acetic anhydride is the key product. Their paper was presented at the American Institute of Chemical Engineers Spring National Meeting held in Houston, Texas earlier this year.
In 1983 Eastman Chemical Company began production of a new generation of coal-derived chemicals. Commercial facilities include a coal gasification plant for synthesis gas manufacture, raw gas cleanup and separation facilities, a sulfur recovery unit, a coal-fired steam plant, and chemical plants to produce methanol, methyl acetate, acetic acid, and acetic anhydride. The original plant gasified approximately 900 tons of coal per day to produce 500 million pounds of acetic anhydride, 150 million pounds of acetic acid, 390 million pounds of methyl acetate, and 365 million pounds of methanol per year.

**Chemicals from Coal**

A flowsheet of the chemicals from coal plant is shown in Figure 1. Oxygen and coal slurry are introduced into the gasifier under conditions of elevated temperature and pressure. The product gas is mainly carbon monoxide and hydrogen, which makes the unit particularly suitable for the production of chemical feedstocks. Because the raw gas is generated at elevated pressures, the size of the gas cleanup equipment is reduced, and the need to compress the product gas prior to its use as a chemical feedstock is minimized.

The gasifier product is scrubbed with water to cool the gas and to remove any ash particles. A portion of the gas stream is sent to a water-gas shift reactor to increase the hydrogen content. Low-pressure steam is generated as the product gas is cooled before additional purification. The full recovery of this heat increases the thermal efficiency of the process and is important for economical operation of the chemical processes which utilize the steam, say the authors.

The sulfur in the coal is converted to hydrogen sulfide. Carbon dioxide and hydrogen sulfide are absorbed by a cold methanol wash. The remaining syngas is cryogenically separated into the carbon monoxide feed for the acetic anhydride plant and a hydrogen-rich stream suitable for methanol production. Conversion of the sulfide to elemental sulfur results in 99.77 percent of the sulfur originally contained in the coal being recovered in molten form, which is then sold as a coproduct of the operation.

Methanol is produced by using a catalytic, gas-phase reactor operating at elevated temperature and pressure. The proper gas-feed composition for methanol production is formed by combining the hydrogen-enriched syngas from the shift reac-

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**FIGURE 1**

**OVERALL BLOCK FLOW DIAGRAM FOR COAL GASIFICATION—ACETIC ANHYDRIDE COMPLEX**

[Diagram showing the flow of materials through the gasification and chemical production process, including oxygen, coal gasification plant, gas purification, sulfur recovery plant, and methanol plant.]
tor and the hydrogen-carbon monoxide stream from the gas separation unit.

Methanol made from synthesis gas is reacted with recycle acetic acid from cellulose esters manufacturing to form methyl acetate. This process has as its principal component a reactor-distillation column in which acetic acid and methanol flow countercurrently, reacting and flashing simultaneously at each stage. The acetic acid serves the dual function of reactant and extractive agent to remove water and methanol from their methyl acetate azeotropes. This process also consists of two side-draw columns and an optional methanol recovery column.

In the final step of the process, purified carbon monoxide from the gas separation plant is reacted with methyl acetate to form acetic anhydride by using a rhodium-lithium catalyst system and a process developed by Eastman. Part of the acetic anhydride is reacted with methanol to coproduce acetic acid. The methyl acetate resulting from this reaction is cycled for carbonylation in the acetic anhydride reactor system. The acetic acid and acetic anhydride are refined in the distillation section of the plant.

Overall Technological and Business Achievements

The Eastman chemicals from coal plant is not a demonstration unit. It is an economically attractive process for the commercial production of acetic anhydride. The complex puts together many technologies, some licensed, others developed by Eastman. Several of the factors that contribute to the favorable economics are described below.

The hydrogen-to-carbon monoxide ratio of the synthesis gas is well suited to the combined production of methanol and acetic anhydride. Hydrogen, needed in relatively minor quantities for the carbonylation reaction requires the use of a cold box fractionation, so that the appropriate low concentration can be achieved.

The methyl acetate and acetic anhydride plants are highly energy efficient, and they use medium- and low-pressure steam produced by cooling the gasifier product. Elimination of the need for the radiant-heat section of the gasifier to produce high-pressure steam reduced the cost and improved the reliability of the gasifier.

The acetic anhydride is used in existing processes to make cellulose acetate. The reaction with cellulose produces byproduct acetic acid, which can be recycled to the methyl acetate plant to react with methanol. This combination of processes eliminated the need to construct an acetic acid plant.

According to the authors, the following coal feedstock advantages are important:

- The operating cost of a coal-based chemical plant is less than that for a natural gas or petroleum-based plant.
- The cost of coal is closely related to mining and delivery costs and is less subject to an unstable political environment than is petroleum.
- Eastman is located very near the Appalachian coal fields, which minimizes the delivery costs.
- Coal gasifiers can use less expensive high-sulfur coal, which is undesirable for power plant use. The sulfur is recovered and sold to further improve the economics.

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4-16
UCG PROJECT PROPOSED FOR PENNSYLVANIA ANTHRACITE REGION

Energy International Corporation (EI) is hoping to put together an underground coal gasification (UCG) project in the anthracite coal region of northeastern Pennsylvania. Cooperative funding from the federal government would be sought under Round 5 of the Clean Coal Technology Program in 1992.

Technology

The UCG process proposed by EI involves operation of an in situ reactor created by drilling wells into a steeply dipping coal seam, igniting the seam, and injecting oxygen and steam into the seam to gasify the coal. The actual process is similar to that in a fixed-bed surface gasifier. The product gas is a mixture of carbon monoxide, carbon dioxide, hydrogen, methane, steam, and higher hydrocarbons. The gas is cleaned and processed at the surface.

The technology is considered to be proven, first with early Russian experience, second by Gulf Oil Company and EI initiatives going back about 20 years, and lastly by United States Department of Energy's activities beginning in the early 1970s. UCG got its start and early development in the Soviet Union beginning as early as 1928. The first field experiments were performed in 1933 and, by the time of World War II, the Soviets had several commercial facilities in operation. UCG activity in the Soviet Union peaked during the 1960s but continues in those locations where it has not been displaced by cheap and abundant natural gas.

Resource

There are several billion tons of anthracite in northeastern Pennsylvania that EI believes to be amenable to UCG. Assuming a 50 percent recovery, 1 billion tons of anthracite is the energy equivalent of 15 trillion cubic feet of natural gas, or about 10 percent of the conventional natural gas reserves in the United States.

The anthracite that is most suitable for UCG is found in steeply dipping beds. These conditions have discouraged conventional mining operations but are particularly well suited for UCG, as demonstrated by Gulf Research & Development Company at the Rawlins, Wyoming test completed in 1981. EI's subsequent initial examination of the steeply dipping anthracite resource has shown a striking correspondence in critical parameters to the successfully demonstrated Rawlins coal.

Permitting/Licensing

Environmental conditions for UCG operations in the United States have been closely scrutinized. UCG field tests, supervised by EI personnel in Wyoming during 1979, 1981, and 1988, were the first to be regulated by the Wyoming Department of Environmental Quality (DEQ) under commercial permits. The permitting regulations represent the most comprehensive controls available on UCG and have been developed through the cooperative efforts of EI and the DEQ. These controls required extensive site characterization work with subsidence monitoring and hydrologic testing of aquifers before, during and after the UCG operations.

Preliminary discussions with the Pennsylvania Department of Environmental Resources (DER) suggests that a permitting procedure for the in situ processing of anthracite coal exists within the Mining and Reclamation Division. All activities classified as "mining" operations would be submitted under one application to the DER, Bureau of Mines, and would be bondable. Air quality, water quality, waste management, and process well drilling are all regulated under existing DER agencies.

Current Status

EI says that a substantial amount of background work has been done on the evaluation of the Schuylkill County portion of the anthracite resource. This work suggests good correlation with the western subbituminous UCG activity led earlier by Gulf Oil and more recently by EI. Current discussions with local anthracite interests suggest that additional portions of the resource, located below the water table, may also be of sufficient quality to be applicable to UCG.

It is anticipated that the proposed small cogeneration facility will qualify for funding under the Clean Coal Technology Program. In addition, the UCG process will qualify for a nonconventional energy tax credit under Section 29 of the United States tax code. It is also anticipated that the power generated from this initial facility can be consumed locally at a price which will provide an acceptable payout.

Commercialization

Stage 1 of the project will be the installation of a small cogeneration facility fueled by gas produced by UCG from two in situ reactors. The plant generators will be driven by two diesel cycle gas engines or alternatively by gas turbines.

Stage 2 of the project will be the commercial development of the anthracite resources based on the successful operations of the Stage 1 power plant for the first 2 years. With a stable low-cost source of gas from anthracite, many new industries

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manufacturing methanol, chemicals or liquid transportation fuels could be established.

The Stage 1 project will have a capital cost in the range of $30 to $50 million and will generate revenues in excess of $10 million per year for its 20 to 40 year life. The Stage 2 project would be expected to have a capital cost in the $100 to $200 million range and would produce revenues in the range of $40 to $100 million per year. Each 1 billion tons of unmineable resource that proves applicable and available to commercialization by UCG would support 10 to 20 Stage 2 projects.

El states that the Stage 1 project could be operating commercially by late 1995. The first of the Stage 2 projects could be operating commercially by 1999.

#####

JOINT RESEARCH TEAMS ATTACK OIL FROM COAL CHALLENGE

The United States Department of Energy (DOE) has asked five research teams to join the effort to reach the $30 per barrel mark for making liquid petroleum substitutes from coal.

"Since World War II, high costs have been the dominant barrier to the commercial viability of making petroleum substitutes from coal," said L.G. Stuntz, DOE's Acting Assistant Secretary for Fossil Energy. "The National Academy of Sciences identified $30 per barrel as a reasonable cost goal, at least at the laboratory stage, over the next 5 to 10 years."

The five research teams will be led by SRI International of Menlo Park, California; the University of Kentucky Research Foundation; Amoco Oil Company of Naperville, Illinois; Hydrocarbon Research Inc. of Princeton, New Jersey; and Canadian Energy Development Inc. which will team with the Alberta (Canada) Research Council.

The teams will embark on an intensive 2-year research effort to apply recent technological advances to cut the cost of coal liquids, what DOE calls an attempt to "leapfrog" today's synthetic liquid fuels technology. The five teams will share in about $5 million in federal research funds over the next 2 years.

In a related effort, DOE has selected M.W. Kellogg, of Houston, Texas to build a generic small-scale, coal-to-liquids engineering facility at the government's Pittsburgh Energy Technology Center (PETC) in Pennsylvania. Industry will be able to use the bench-scale unit to test and improve coal liquids processes emerging from the research program.

The new bench-scale test facility will include facilities for direct and indirect liquefaction testing. DOE commissioned design and construction of the highly-flexible unit to provide a way of scaling up a variety of emerging liquefaction processes without constructing new testing facilities for each new idea.

Some firms may still opt to use their own testing units, but research organizations that do not own bench-scale testing units will be able to bring their concepts to PETEC for testing.

The facility will be adaptable to a wide range of process designs and will be able to process up to 200 pounds of coal per day. The unit is scheduled to be available in 1993.

Following is a description of the five new research efforts.

University of Kentucky

The University of Kentucky's Center for Advanced Energy Research will focus on the integration of several pretreatment and reaction processing schemes. The processes include oil agglomeration, solvent hydrogenation, carbon monoxide pretreatment, solvent dewaxing, addition of a dispersed catalyst, and fluid coking. Assisting in this project will be Consolidation Coal Company (oil agglomeration technology), Sandia National Laboratory (catalyst technology), and LDP Associates (economic analyses).

SRI International

With support from Bechtel Corporation, SRI International will develop and optimize various catalysts to determine their effect on product and the overall conversion. In addition, they will explore the effect of reacting coal in the presence of carbon monoxide and hydrogen. While all types of coals are expected to benefit from incorporation of these steps, they are expected to work especially well with low rank coals.

Amoco Oil Company

Amoco will lead a team of Foster Wheeler Development Corporation, Auburn University, Penn State University, and Hazen Research Inc. in a project to identify ways to cut costs in the existing two-stage liquefaction process. The Foster Wheeler ASCOT process, an asphalt coking process, will be used to recover additional distillates from the heavy fractions. Emphasis will be on low rank coals.

Hydrocarbon Research, Inc. (HRI)

HRI will compare liquid yields from various coals in two- and three-stage coal liquefaction systems. Coals to be studied include Illinois No. 6 bituminous and Wyoming subbituminous coals. The specific reactor types to be studied include shaken micro-autoclaves, small fixed-bed reactors, and continuous Robinson-Mahoney reactors with a catalyst basket.
The combined CED/ARC team will examine the possibility of integrating three separate processing stages—a patented selective oil agglomeration technique (AGLOFLOAT), a patented two-stage coal slurry pretreatment step, and a newly-developed counterflow reactor hydroconversion process—into a single, low-cost process. The resulting process is expected to be particularly well-suited for high-ash, low-rank coals.

STATUS OF CCT PROJECTS UPDATED

The United States Department of Energy (DOE) recently published an updated status report on the 35 projects in its Clean Coal Technology Demonstration Program. The schedule for each of these projects is shown in Figure 1 on the next page.

The following paragraphs briefly summarize the current status of each of these 35 projects which were selected for federal funding support under the first three rounds of DOE’s solicitations for clean coal technology projects.

Round 1 Projects

Advanced Cyclone Combustor with Integral Sulfur, Nitrogen, and Ash Control. Coal Tech Corporation, Williamsport, Pennsylvania. Project work has been completed with the air-cooled combustor having logged some 900 hours of operation representative of industrial application. Publication and distribution of the final report was planned for mid-1991.

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection. Energy and Environmental Research Corporation, Hennepin and Springfield, Illinois. Evaluation of the results of 32 basic gas reburning tests completed in March at the Hennepin site (tangentially-fired boiler) has shown the strong effect of excess air on NOx reduction. A second series of parametric gas reburning tests is in progress. Startup of the sorbent injection system was initiated. At the Springfield site (cyclone-fired boiler), all civil construction work has been completed. Boiler outage activities were initiated in May and continued in June.

LIMB Demonstration Project Extension. The Babcock & Wilcox Company, Lorain, Ohio. Coolside duct injection tests (1,729 operating hours) have been successfully completed with up to 70 percent SO2 removal. Combinations of four sorbents and three coals are being tested in the current LIMB extension demonstration which was scheduled for completion late this summer.

Nucla CFB Demonstration Project. Colorado-Ute Electric Association, Inc., Nucla, Colorado. The project has completed the scheduled 2 year testing program (15,707 hours) demonstrating New Source Performance Standards reductions for SO2 and NOx emissions. Preparation of the final technical report and economic evaluation report was scheduled for completion in October 1991.

Prototype Commercial Coal/Oil Coprocessing Project. Ohio Clean Fuels, Inc., Warren, Ohio. After allowing a series of extensions to restructure the project and a review of the most recent proposal which failed to meet financial goals, the Department ended its sponsorship of the project.

Tidd PFBC Demonstration Project. American Electric Power Service Corporation on behalf of Ohio Power Company, Brilliant, Ohio. Over 300 hours of operation have been logged including a continuous run of more than 60 hours reaching a full bed level of 127 inches. Power generation rates in excess of 50 megawatts of power were achieved.

Advanced Coal Conversion Process Demonstration. Western Energy Company, Colstrip, Montana. DOE approved formation of the Rosebud SynCoal Partnership between Western Energy Company and Northern States Power Company. Installation of piling has been completed and construction work on foundations is in progress.

Development of the Coal Quality Expert. Combustion Engineering, Inc. and CO2, Inc., Homer City, Pennsylvania. Utility scale combustion tests in combination with smaller scale tests to determine correlations have been conducted on selected Wyoming and Oklahoma coals.

Arvah B. Hopkins Circulating Fluidized Bed Repowering Project. The City of Tallahassee, Tallahassee, Florida. Design activities are continuing. DOE has approved the circulating fluid-bed boiler subcontract to Foster Wheeler Corporation.

Round 2 Projects

Advanced Flue Gas Desulfurization Demonstration Project. Pure Air, a joint venture company, Gary, Indiana. Design is essentially complete and construction is about 46 percent complete. The SO2 absorber is structurally complete and work has begun on resin lining of the absorber and ancillary equipment.

180 MWe Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of NOx Emissions for Coal-Fired Boilers. Southern Company Services, Inc., Lynn Haven, Florida. Short- and long-term baseline performance testing was completed. The low NOx concentric firing system (LNCFS) Level II equipment (one of three basic aircoal feed configurations to be tested) was installed during the plant outage in April 1991. Preliminary
results of operating the LNCFS Level II system indicated NO\textsubscript{x} reductions of up to 35 percent compared to the baseline emissions data.

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler. Southern Company Services, Inc., Coosa, Georgia. Long-term testing of advanced overfire air (AOFA) for evaluation of NO\textsubscript{x} reduction has been completed with 80 days of data collected. Based on preliminary performance testing of AOFA, NO\textsubscript{x} reduction of 20 percent has been measured. The 24 new low NO\textsubscript{x} burners (LNB) were installed during the March 1991 outage at Hammond Plant Unit No. 4 and LNB testing is in progress.

Cement Kiln Flue Gas Recovery Scrubber. Passamaquoddy Tribe, Thomaston, Maine. Construction and startup activities were essentially completed in March. Following a brief shutdown, plant operations resumed in June with the scrubber coming online after replacing the heat exchanger.

Demonstration of Coal Reburning for Cyclone Boiler NO\textsubscript{x} Control. The Babcock & Wilcox Company, Cassville, Wisconsin. Design work is essentially complete. The Environmental Assessment to support construction activities has been approved. Construction has begun with the installation of foundations. Work to be done during the Nelson Dewey Generation Station spring outage was completed in preparation for the installation of the reburn system during the boiler outage scheduled for September 1991.

Innovative Coke Oven Gas Cleaning System for Retrofit Applications. Bethlehem Steel Corporation, Sparrows Point, Maryland. Erection of major mechanical equipment and structural steel has been completed and hydrostatic testing of
vessels is in progress. Pre-operational tests and startup were scheduled for this fall.

**Demonstration of Innovative Applications of Technology for the CT-121 FGD Process.** Southern Company Services, Inc., Newman, Georgia. Construction activity is well under way and final design activities continue. Hydrostatic testing of the limestone slurry tank has been successfully completed and internals are being installed in the jet-bubbling reactor.


**Low NOx/SOx Burner Retrofit for Utility Cyclone Boilers.** TransAlta Resources Investment Corporation, Marion, Illinois. Most of the major equipment items have been ordered and construction is approximately 50 percent complete. Engineering and design work continue with operation scheduled for the end of 1991.

**PFBC Utility Demonstration Project.** American Electric Power Service Corporation, as agent for The Appalachian Power Company and the Ohio Power Company, New Haven, West Virginia. Detailed life cycle cost studies comparing PFBC repowering and greenfield plants against conventional power plants with scrubbers are continuing.

**Demonstration of Selective Catalytic Reduction Technology for the Control of NOx Emissions from High-Sulfur Coal-Fired Boilers.** Southern Company Services, Inc., Pensacola, Florida. Detailed design is in progress on the slip stream ductwork and internals to ensure that the flow regime is representative of actual operation.

**SOX-NOX-ROX Box Flue Gas Clean-up Demonstration Project.** The Babcock & Wilcox Company, Dilles Bottom, Ohio. The construction phase has been approved and installation activity began in mid-April. Initial major process equipment installation is proceeding ahead of schedule. All long lead-time equipment is on-site.

**WSA-SNOX Flue Gas Cleaning Demonstration Project.** Combustion Engineering, Inc., Niles, Ohio. Design work is complete and all major equipment and materials have been procured. Construction is proceeding on schedule with significant work completed on the heat exchanger, fabric filter and support towers. Operation was to begin in November 1991.

**Round 3 Projects**

**Blast Furnace Granulated Coal Injection System Demonstration Project.** Bethlehem Steel Corporation, Burns Harbor, Indiana. Negotiations were completed with British Steel Corporation for a licensing agreement. Process design and detailed engineering for process components are continuing.

**Confined Zone Dispersion Flue Gas Desulfurization Demonstration.** Bechtel Corporation, Indiana County, Pennsylvania. Tie-in of the new duct extension was completed during the boiler shutdown in early May, as scheduled. Based on successful wind tunnel testing, the atomizer nozzles were placed on order for installation at the Seward Station.

**10 MW Demonstration of Gas Suspension Absorption.** Air-Pol, Inc., Paducah, Kentucky. Process design is continuing. A new project schedule reflecting a delay in the operation date to October 1, 1992, has been proposed by the participant to accommodate the availability requirements of the host site.

**Healy Clean Coal Project.** Alaska Industrial Development and Export Authority, Healy, Alaska. The Cooperative Agreement was awarded April 11, 1991. Design activities are in progress.

**Integrated Dry NOx/SOx Emission Control System.** Public Service Company of Colorado, Denver, Colorado. Design work is in progress with emphasis on control systems and the urea injection system. Engineering began on the low NOx burners and the NOx ports.

**Air-Blown/Integrated Gasification Combined Cycle Project.** Clean Power Cogeneration, Inc., Tallahassee, Florida. Conceptual process and plant design studies, and work toward establishing cost and schedule baselines are continuing.

**LIFAC Sorbent Injection Desulfurization Demonstration Project.** LIFAC North America, Richmond, Indiana. All major tie-in activities were completed during the March outage of the Richmond Power and Light’s Whitewater Valley Unit No. 2. (The balance of the LIFAC equipment can be installed without impacting plant operations.) All long lead procurement activities have been completed.

**Liquid Phase Methanol Process.** Air Products and Chemicals, Inc., Dakota Gasification Company, Beulah, North Dakota. The negotiation schedule was extended to fall 1991 to evaluate an alternate site.

**Full-Scale Demonstration of Low-NOx Cell Burner Retrofit.** The Babcock & Wilcox Company, Aberdeen, Ohio. Fabrication of the low-NOx cell burners was completed. All 24 sets of burners and NOx ports have been shipped to the Dayton Power and Light job site for installation during the planned September 1991 boiler outage.

**ENCOAL Mild Coal Gasification Project.** ENCOAL Corporation, Gillette, Wyoming. The project remains ahead of schedule with detailed design 90 percent complete. Major
equipment items were to be delivered and assembled by midsummer.

Commercial Demonstration of NOXSO $SO_2/NO_x$ Removal Flue Gas Cleanup System. MK-Ferguson Company, Niles, Ohio. Project definition and design activities are in progress following execution of the Cooperative Agreement in March 1991.

Pressurized Circulating Fluidized Bed Demonstration Project. Dairyland Power Cooperative, Alma, Wisconsin. Negotiations were completed with a partnership formed by Dairyland Power Cooperative and Iowa Power, Inc., DMEC-1 Limited Partnership, to demonstrate repowering of a 70 megawatt PCFB integrated with a topping combustor and gas turbine. The host site is Iowa Power’s Des Moines Energy Center located in Pleasant Hill, Iowa. The proposed agreement was submitted for Congressional review in June.

Evaluation of Gas Reburning and Low-NOx Burners on a Wall-Fired Boiler. Energy and Environmental Research Corporation, Denver, Colorado. Purchase orders for long lead items are being made to allow retrofit work to proceed during the Cherokee Station boiler outage which was scheduled for August 1991. Baseline test data were collected during June-July 1991.

###

**SGI ACTIVITIES MULTIPLY**

SGI International continues to actively pursue a number of clean coal commercialization activities around the world.

**Alaska**

In August, SGI representatives met with Alaska’s Deputy Commissioner of International Trade and Development to discuss the potential for increasing Alaska coal production and export to Pacific Rim countries. Discussions are now under way for the installation of LFC (liquids from coal) refineries in Alaska with two Alaskan companies.

The LFC technology produces a low sulfur liquid substitute for No. 6 fuel oil and a clean solid fuel with the quality of bituminous coal.

**Contract with DOE**

SGI recently signed a $700,000 contract with the United States Department of Energy’s (DOE) Morgantown Energy Technology Center (METC) to supply METC with LFC clean fuel product samples produced from a variety of United States coals. Coals and lignites from several regions that are candidates for large scale LFC refineries will be processed into coproduct solid and liquid clean fuels in SGI’s LFC process testing facilities at the SGI Development Center in Perrysburg, Ohio.

**Poland**

SGI representatives continue to advance plans to establish LFC refining plants in Poland. Follow-up meetings have been held with the Polish Central Coal Institute in Katowice, Poland and with senior government officials in Warsaw. Several Polish coals have now been designated for initial feasibility studies.

In addition, meetings have been held with the Economic Advisor to the President and the Deputy Minister for Environment, Natural Resources and Forestry. These meetings have helped to advance SGI’s program for using LFC refining plants to reduce environmental pollution and to enhance economic growth in Poland.

**Japan**

In November, SGI presented information on the LFC refining process to the U.S./Japan Business Conference held in Leesburg, Virginia. Several Japanese companies have reportedly expressed a strong interest in utilizing the process for refining coals in Australia, Canada, Indonesia, Thailand, Eastern Europe and the United States.

**ENCOAL Project**

Construction of the 1,000 ton per day LFC refinery near Gillette, Wyoming continues ahead of schedule. Startup personnel have already arrived at the plant. The first shipments of LFC products to customers is now anticipated for the first half of 1992. ENCOAL Corporation’s $72 million project is 50 percent funded by DOE’s Clean Coal Technology Program.

###

**DGC SHOWS $10 MILLION PROFIT IN 1990**

According to the Basin Electric Power Cooperative 1990 Annual Report, the Dakota Gasification Company (DGC) made a $10 million profit in 1990. Much of that profit, however is attributable to byproduct sales and interest income.

The report notes that byproduct development, which has continued in 1991, can provide the extra revenue needed to keep the synfuels plant operating until natural gas revenue can consistently exceed the plant’s operating costs.

DGC is the wholly owned subsidiary of Basin Electric that owns and operates the Great Plains Synfuels Plant, located about 7 miles northwest of Beulah, North Dakota. The syn-
fuels plant produces natural gas from a lignite deposit that contains approximately 250 million tons of coal.

The plant also produces numerous byproducts. The byproducts produced during 1990 were ammonia, sulfur and liquid nitrogen. The commercial production of two additional byproducts, phenol, and a mixture of krypton and xenon gas, began in 1991.

Byproduct Development

During 1990, DGC invested approximately $20.4 million to construct a facility to remove and purify phenol from a liquid hydrocarbon stream, a byproduct of the coal gasification process. It also invested $3.6 million to extract a krypton and xenon gas mixture from the synfuels plant's oxygen plant.

DGC's phenol facility has the ability to produce approximately 35 million pounds of phenol a year. This new facility is now also producing a second byproduct stream of cresylic acids.

About 3.6 million liters of a krypton and xenon gas mixture will be produced annually. Union Carbide Industrial Gases Inc. has signed a 15-year agreement with DGC to buy these rare gases.

Argon, carbon dioxide, naphtha and creosote are other potential byproducts that DGC could produce if their profit potential improves.

The large carbon dioxide stream produced at the synfuels plant could be used throughout the Williston Basin Region for enhanced oil recovery. While DGC would directly benefit from the sale of carbon dioxide, Basin Electric and its member systems would also benefit from the increased sales of electricity used to pump oil from these rejuvenated fields. Purifying and liquefying the carbon dioxide at the synfuels plant for this purpose would also create a significant electrical load.

The amount of anhydrous ammonia produced at the plant that is sold for fertilizer represents approximately 10 percent of the North Dakota anhydrous ammonia market. The sulfur that is produced at the plant is sold to a producer of sulfuric acid. The liquid nitrogen produced by the plant is sold mostly to local distributors of welding gas mixtures and to oil producers. These three byproducts together earned revenue of approximately $4.2 million in 1990.

Operations

In 1990, the synfuels plant achieved both new daily and monthly production records while nearly matching the annual production record set in 1989. These achievements were reached despite considerable maintenance work performed on the plant during 1990. In addition, there were production limitations because the four purchasers of the natural gas have insufficient firm transportation rights on pipelines necessary to transport the gas to end users.

Daily production of natural gas averaged 148.2 million cubic feet, or 7.8 percent above the plant's design capacity of 137.5 million cubic feet per day. A daily production record of 164.2 million cubic feet was set on May 28, 1990. The plant set a monthly production record in March 1990 by producing an average of 160 million cubic feet of natural gas daily, 14.1 percent above the plant's design capacity.

###
GOVERNMENT

NINE NEW CLEAN COAL PROJECTS SELECTED

The United States Department of Energy (DOE) has selected nine new projects under Round 4 of the multibillion dollar Clean Coal Technology Program.

The selected projects have a combined value of nearly $1.5 billion. Together with 33 other active ventures selected in earlier competitions, the total government-industry investment in clean coal technology demonstrations is $4.6 billion, 60 percent of which is funded by private companies and states.

"Today's action moves us closer to our goal of having in place a full complement of 'showcase' demonstration plants that I believe represent the future new look of the nation's coal fired power industry," said Energy Secretary J.D. Watkins. "Many of the technologies virtually eliminate the major pollutants commonly associated with acid rain, and several offer the dual benefits of superior environmental performance coupled with more efficient, lower cost power generation."

Included in the selection are three large-scale, high-efficiency electricity generating projects. The integrated coal gasification combined cycle technologies to be used in these projects are expected to produce as much as 25 percent more electricity from a given amount of coal than current conventional coal-burning methods. In addition, they remove almost all of the pollutants known to cause acid rain.

These three projects account for nearly 75 percent of the approximately $568 million in federal funds to be shared by the nine selected projects, pending successful negotiations.

DOE said last January in issuing its call for proposals that it would give extra consideration to projects that increase the efficiency of coal-based energy systems.

"A common feature of virtually every new technology supported by the National Energy Strategy is its potential to more efficiently transform energy raw materials into the energy services we need. These clean coal technology projects reflect that commitment to greater energy efficiency in the generation of electricity," Watkins said.

DOE selected four projects that will demonstrate high-performance pollution control devices that can be added to existing or new power stations. Each of these advanced devices will be capable of meeting the nation's more stringent sulfur and nitrogen pollutant controls required by the Clean Air Act Amendments of 1990.

Two other projects will demonstrate techniques to change coal into new, cleaner burning fuel forms that can be used in a variety of power generating, industrial or other energy applications.

DOE received 33 clean coal technology proposals last May. (See the Synthetic Fuels Report, June 1991, page 4-17.) Since then, a team of nearly 100 federal officials, headed by an eight-member "source evaluation board," have reviewed the proposals. The board scored such factors as technical readiness, environmental performance, improved efficiency and the proposer's commitment and capability to jointly finance the venture.

After reviewing the board's evaluation report, DOE's Deputy Assistant Secretary for Coal Technology, J.S. Siegel, made the final selections.

The new projects are located in eight states, as shown in Figure 1. In all, the Clean Coal Technology Program is sponsoring 42 ventures in 22 states.

The total federal assistance sought by the nine winning proposers exceeds the $568 million DOE allotted for the competition. The department, however, expects to negotiate changes in certain projects, such as excluding ancillary hardware and reducing the length of operating times.

FIGURE 1

NEW CCT–IV PROPOSED PROJECT SITES

SOURCE: DOE

SYNTHETIC FUELS REPORT, DECEMBER 1991
Definitive agreements for the selected projects are being negotiated; DOE has allotted 1 year to complete the negotiations.

The nine selected projects are briefly described below. Both DOE proposed cost share and project costs are "as proposed" and subject to negotiation.

**Wabash River Coal Gasification Repowering Project**

This $59.19 million project will be located in West Terre Haute, Indiana. DOE is being asked to fund 41 percent of the project cost. (See article elsewhere in this issue, for a detailed description of the project.)

The project is a joint venture of Destec Energy, Inc. of Houston, Texas and PSI Energy Inc. of Plainfield, Indiana.

The project will repower one of six units at PSI Energy's Wabash River Generating Station, using a single train, oxygen-blown Destec gasification plant, and the existing steam turbine, in a new integrated gasification combined cycle (IGCC) configuration to produce 265 megawatts of electricity from 2,500 tons per day of high sulfur Eastern bituminous coal.

**Toms Creek IGCC Demonstration Project**

TAMCO Power Partners, a partnership of Tampella Power Corporation, Williamsport, Pennsylvania, and Coastal Power Production Company, Roanoke, Virginia, will site this $291.1 million project in Coeburn, Virginia. The requested funding share from DOE is 49.7 percent.

The project will be a new 107 megawatt (55 megawatt net coal based) IGCC power plant facility located at an existing coal mine. A single air blown, U-Gas fluidized bed gasifier—430 tons per day of local bituminous coal—with hot gas cleanup (regenerative zinc titanate fluid beds and gasifier limestone injection for sulfur removal, high temperature candle filters for particulate removal) will be demonstrated. Power will be generated with two gas turbines, (one coal gas fired, the other natural gas fired), and one steam turbine.

This project is described in detail on page 4-12 of the September 1991 issue of the Pace Synthetic Fuels Report.

**Pinion Pine IGCC Power Project**

Sierra Pacific Power Company, Reno, Nevada, has asked DOE to fund 50 percent of the total projected project cost of $340.7 million.

The project will be a new 80 megawatt IGCC plant located at an existing Sierra Pacific facility. A single air blown, KRW fluidized bed gasifier—800 tons per day Western bituminous coal—with hot gas cleanup (gasifier limestone injection with zinc ferrite fixed bed reactors for sulfur removal, high temperature candle filters for particulate removal) will be demonstrated. Power will be generated with dedicated combustion and steam turbines.

The project, to be located near Reno, Nevada, is described in more detail in the Pace Synthetic Fuels Report, September 1991, page 4-2.

**CANSOLV Process Demonstration Project**

Union Carbide Chemicals and Plastics Company Inc. of Danbury, Connecticut will demonstrate its CANSOLV process at the ALCOA Corporation Warrick Power Plant in Newburgh, Indiana. DOE is being asked to fund 50 percent of the $32.7 million project.

The CANSOLV process is a regenerable system that removes SO\textsubscript{2} from a flue gas stream by contact of the gas with an aqueous amine absorbent. The absorbent is regenerated thermally and the SO\textsubscript{3} is recovered as a marketable liquid.

**Custom Coals International—Self Scrubbing Coal**

Custom Coals International is a joint venture of Duquesne Ventures (subsidiary of Duquesne Light), Pittsburgh, Pennsylvania, and Genesis Research Corporation, Carefree, Arizona.

The self scrubbing coal technology involves the integration of advanced physical coal cleaning with coal sorbent reconstitution techniques to produce a coal based fuel to meet an emission limit of 1.2 pounds of SO\textsubscript{2} per million BTU. The product is called "Carefree Coal."

The coal will be produced at Duquesne Light's Greensboro, Pennsylvania coal cleaning plant and test burns will be conducted at electric generating facilities in Richmond, Indiana and Springdale, Pennsylvania. DOE is being asked to share 50 percent of the $76.1 million project cost.

**Milliken Clean Coal Technology Demonstration Project**

New York State Electric & Gas Corporation will demonstrate a combination of cost effective emission reduction and efficiency improvement technologies: formic acid enhanced wet limestone scrubbing, Stebbins tile-lined split module absorber, NO\textsubscript{X} OUT urea injection system for NO\textsubscript{X} removal, and a heat pipe air heater system.

The $158.6 million project will be sited at Lansing, New York. The requested DOE share of funding is 40.7 percent.

**Micronized Coal Reburning Demonstration**

This $7.3 million project, proposed by the Tennessee Valley Authority (TVA), will be sited at Paducah, Kentucky. DOE is being asked to fund 48 percent of the project cost.
The project will demonstrate the reduction of NO\textsubscript{X} emissions by the retrofit of coal reburning on an existing wall-fired boiler at the TVA Shawnee Fossil Plant. A low sulfur Eastern bituminous coal, micronized (80 percent less than 325 mesh), will be fired in the boiler in amounts up to 30 percent of total fuel feed. NO\textsubscript{X} emissions are expected to be reduced by 50 to 60 percent.

Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

ThermoChem, Inc., Columbia, Maryland, will demonstrate a pulse combustor from Manufacturing and Technology Conversion International Inc. (MTCI) in an application for steam gasification of coal at Weyerhaeuser Paper Company’s Containerboard Division mill, to produce fuel gas and steam to replace existing hog fuel boilers. The MTCI process incorporates an innovative indirect heating process provided by multiple resonance tube pulse combustors immersed in a fluid bed of coal. Approximately 429 tons per day of Wyodak Western subbituminous coal will be processed.

A detailed description of this $37.3 million project is provided on page 4-6 of the September 1991 issue of the Pace Synthetic Fuels Report. The requested DOE funding level is 50 percent. The project will be sited at Springfield, Oregon.

Cordero Coal Upgrading Demonstration Project

Located in Gillette, Wyoming, this Cordero Mining Company project will demonstrate the Carbontech Syncoal Process to upgrade high moisture, low rank coals.

The technology consists of a two-stage drying process. In the first stage, hot fuel oils drive moisture from the coal. Hot flue gas in the second stage completes the drying of the oil coated coal to produce a high heating value, moisture resistant, attrition and dusting resistant and spontaneous combustion resistant solid fuel. About 1,200 tons of Wyodak seam Western subbituminous coal will be processed.

A more detailed project description is provided in the Pace Synthetic Fuels Report, September 1991, page 4-5. DOE is being asked to fund 50 percent of the $34.3 million project cost.

DOE TELLS CONGRESS NO ADDITIONAL WORK NEEDED ON COAL REFINERIES

In a recent report prepared for Congress, the United States Department of Energy (DOE) identifies the research and development (R&D) needs of coal refineries but concludes that "... there appears to be little or no need to establish new R&D programs specifically toward coal refineries ..." The report suggests that other programs, such as the Clean Coal Technology Program, are already engaging in the R&D activities that are relevant to coal refineries.

"Coal Refineries: A Definition and Example Concepts" defines a coal refinery as "a system consisting of one or more individual processes integrated in such a way as to allow coal to be processed into two or more products supplying at least two different markets."

DOE says this definition was used to insure that concepts producing a range of refined products from coal for multiple markets are included while excluding processes that produce only one product supplying a single market. The report identifies and discusses 27 coal refinery concepts.

The report notes that several general classes of concepts meet the strict definition of a coal refinery, but were specifically excluded from consideration. Those concepts excluded are integrated gasification combined cycle, coal preparation or beneficiation, and cogeneration.

DOE divided coal refinery concepts into four general categories as follows:

- Devolatilization
- Gasification
- Liquefaction
- Bioprocessing

The basis for these categories is the principal processing step(s) used in refining the coal. Rudimentary descriptions of the refinery categories are as follows.

Devolatilization

The devolatilization category contains concepts that process coal under non-oxidizing or mild-oxidation conditions (Figure 1). The immediate products from these concepts usually include a gas that can be used as a fuel or as a feedstock for chemical production, some liquids, and a high-carbon char. These products, however, are sometimes processed further and may not always correspond with the final products. In general, the degree of coal conversion is usually more limited than that associated with the gasification or liquefaction concepts.

These concepts generally use low temperature and pressure (approximately 1,000 to 1,500°F and near atmospheric pressure) conditions to drive off the volatiles in the coal, leaving a devolatilized, solid char behind. The volatiles are then condensed into a variety of liquid products while the char can be used as a solid fuel, mixed into a slurry, or upgraded into a higher-value product such as form coke or carbon black. The liquid yield from these concepts is generally quite low, at less than 1 barrel of liquids per ton of coal.
### FIGURE 1

**SUMMARY OF DEVOLATILIZATION COAL REFINERY CONCEPTS**

<table>
<thead>
<tr>
<th>COAL REFINERY CONCEPT</th>
<th>SPONSOR / PROPOSENT</th>
<th>MAJOR PRODUCTS</th>
<th>DEVELOPMENT STATUS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calderon</td>
<td>Calderon Energy Co.; Bowling Green, OH</td>
<td>Electricity and methanol</td>
<td>24 ton/day PDU</td>
</tr>
<tr>
<td>Charfuel</td>
<td>Carbon Fuels Corp.; Englewood, CO</td>
<td>Char-liquid-slurry fuel, methanol, ether, naphtha, and BTX</td>
<td>1 ton/hour PDU (using Rockwell hydrolysis reactor)</td>
</tr>
<tr>
<td>Coal Liquid and Coke</td>
<td>CLC Associates; Bristol, VA</td>
<td>Form coke, coal-derived liquids</td>
<td>1,000 lb/hr PDU</td>
</tr>
<tr>
<td>Mild Gasification</td>
<td>Shell Mining Co.; Houston, TX</td>
<td>Solid and liquid boiler fuels</td>
<td>200 lb/hr PDU; Demonstration plant construction underway</td>
</tr>
<tr>
<td>Hydrocarb</td>
<td>Brookhaven National Lab.; Upton, NY</td>
<td>Coal-derived slurry fuel, utility fuel, and (possibly) methanol</td>
<td>Bench scale</td>
</tr>
<tr>
<td>Institute of Gas Technology</td>
<td>Institute of Gas Technology; Chicago, IL</td>
<td>Form coke and coal-derived liquids</td>
<td>100 lb/hr PDU</td>
</tr>
<tr>
<td>Marshall Owen</td>
<td>Marshall Owen Ent.; Reno, NV</td>
<td>Smokeless solid fuel, crude tar, crude light-oil, and high-Btu gas</td>
<td>Concept based on commercial process in England</td>
</tr>
<tr>
<td>SFuel</td>
<td>Institute of Chemical Processing of Coal; Poland</td>
<td>Smokeless solid fuel and electricity</td>
<td>7.2 ton/day pilot plant</td>
</tr>
<tr>
<td>UNDEECIC Mild Gasification</td>
<td>Univ. of N. Dakota Energy and Environ. Research Center; Grand Forks, ND</td>
<td>Form coke and coal-derived liquids</td>
<td>100 lb/hr PDU</td>
</tr>
<tr>
<td>WRI/AMAX Mild Gasification</td>
<td>WRI and AMAX; Laramie, WY</td>
<td>Carbon black, pitches, and diesel-blend fuel</td>
<td>100 lb/hr PDU</td>
</tr>
</tbody>
</table>

**SOURCE:** DOE

**Gasification**

Gasification concepts rely on more severe conditions to convert the coal into a gaseous product consisting of large fractions of carbon monoxide, hydrogen, carbon dioxide, and water (Figure 2). This gaseous product can then be used in one or more ways. It can, after removal of pollutants, be burned in a combustion turbine for the production of electricity. It can be used as a chemical feedstock, or its composition can be adjusted for conversion into products such as substitute natural gas, pure hydrogen, methanol, ammonia, acetic anhydride, and various hydrocarbon fuels.

**Liquefaction**

Concepts in the liquefaction category are generally configured to yield a greater fraction of liquid products than concepts in other categories. These liquids can potentially be used as fuels or as feedstocks for the full slate of petrochemical products (Figure 3, page 29).

Energy and material inputs to these refineries, in addition to the coal, range from natural gas to very heavy crude oils. Bitumen and heavy residual oils are also possibilities for use in some liquefaction concepts. The output products can be similar to those of a large petroleum refinery or they can be more narrow, such as synthetic crude oil.

**Bioprocessing**

Research on biotechnology for coal processing is a growing area and some of the potential applications may be considered to be coal refineries. The bioprocessing category of coal refineries covers solubilizing of coal and conversion to gaseous and liquid products as well as the use of bioorganisms in the conversion of synthesis gas generated by the...
FIGURE 2

SUMMARY OF GASIFICATION COAL REFINERY CONCEPTS

<table>
<thead>
<tr>
<th>COAL REFINERY CONCEPT</th>
<th>SPONSOR / PROPOONENT</th>
<th>MAJOR PRODUCTS</th>
<th>DEVELOPMENT STATUS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coproduction of Acetic Anhydride, Acetic Acid, and Methanol</td>
<td>Tennessee Eastman Co.; Kingsport, TN</td>
<td>Acetic anhydride, acetic acid, and methanol</td>
<td>900 ton/day commercial plant</td>
</tr>
<tr>
<td>Coproduction of Methanol and Electricity</td>
<td>Air Products and Chemicals, Inc.; Allentown, PA</td>
<td>Methanol and electricity</td>
<td>Commercial components; Conceptual design for system; 10 ton/day PDU for methanol</td>
</tr>
<tr>
<td>Coproduction of SNG, Electricity, Methanol, and Chemical Intermediates</td>
<td>Great Plains Coal Gasification Plant; Beulah, ND</td>
<td>SNG, methanol, and electricity</td>
<td>17,000 ton/day commercial SNG plant</td>
</tr>
<tr>
<td>Coproduction of Urea and Electricity</td>
<td>TVA; Chattanooga, TN</td>
<td>Urea and electricity</td>
<td>Commercial components; Conceptual design for proposed system</td>
</tr>
<tr>
<td>Dual Production of Ammonia and Electricity</td>
<td>Adaptation of proposed modification to Ube Industries; Japan</td>
<td>Ammonia and electricity</td>
<td>Commercial components; Conceptual design for system</td>
</tr>
<tr>
<td>Once-Through Fischer-Tropsch with Power Generation</td>
<td>Concept examined for DOE by MITRE Corp.; McLean, VA</td>
<td>Chemical feedstocks, liquid fuels, and electricity</td>
<td>Commercial components; Conceptual design for system</td>
</tr>
<tr>
<td>Shell Middle Distillate Synthesis</td>
<td>Royal Dutch Shell; Netherlands</td>
<td>Naphtha, kerosene, and gas oil</td>
<td>Commercial with natural gas feed</td>
</tr>
</tbody>
</table>

SOURCE: DOE

conventional coal gasification step into liquid and gaseous fuels (Figure 4, page 30).

In most cases, bioprocessing is in the research laboratory stage with some work at the bench-scale level. Engineering work has been done for some processes that may evolve into commercial activities. As compared to the other general categories of coal refineries, the bioprocessing concepts are generally at a lesser state of development.

Devolutilization Research Needs

The 10 coal refinery concepts described in the devolutilization category are designed to achieve the overall objective of reducing the retorting conditions typically associated with the production of coal liquids. Additional issues that arise for concepts in this refinery category include low liquid yield, potential extensive upgrading requirements for these liquids, and the economic value of the solid (char) that remains after the devolutilization process. Issues such as process efficiency, materials handling, resource requirements, and overall economics also exist with these concepts.

According to the DOE report, all of the concepts in the devolutilization category could benefit from R&D activities directed toward the scaleup of current operations to capacities appropriate to evaluate the concept at near commercial conditions. Several of these concepts are currently at the bench or process development unit scale so that significant scaleups would be needed to verify these parameters at near-commercial scale. Development of many of the mild gasification processes in this category is being supported by the DOE Surface Coal Gasification Program.

It could be advantageous to the maturation of these concepts to evaluate the impacts of different coals on the design, operation, and economics of devolutilization refineries. Greater understanding of the influences of coal characteristics on the products and costs of devolutilization refineries would assist in the determination of the full potential of these coal refineries in the marketplace.

Gasification Research Needs

In general, the coal refinery concepts in the gasification category are the most advanced of those considered. The seven concepts presented include some that are operating.
FIGURE 3

SUMMARY OF LIQUEFACTION COAL REFINERY CONCEPTS

<table>
<thead>
<tr>
<th>COAL REFINERY CONCEPT</th>
<th>SPONSOR / PROPOONENT</th>
<th>MAJOR PRODUCTS</th>
<th>DEVELOPMENT STATUS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Agilotherm</td>
<td>Alberta Research Council; Canada</td>
<td>Processed oil and solid fuel</td>
<td>Bench scale</td>
</tr>
<tr>
<td>Catalytic Two-Stage Liquefaction</td>
<td>Hydrocarbon Research Inc.; Princeton, NJ</td>
<td>Transportation fuels, fuel oil, and utility fuel</td>
<td>Similar to 6 ton/day PDU</td>
</tr>
<tr>
<td>Coal Depolymerization-Liquefaction</td>
<td>Department of Fuels Eng.; University of Utah</td>
<td>Coal-derived liquids, kerosene, and oils</td>
<td>Bench scale (Exploratory)</td>
</tr>
<tr>
<td>Coal/Oil Coprocessing</td>
<td>Hydrocarbon Research Inc.; Princeton, NJ</td>
<td>Naphtha, middle distillates, vacuum gas oil, and liquefied petroleum gases</td>
<td>3 ton/day PDU</td>
</tr>
<tr>
<td>Enhanced Coal Liquefaction by Rapid Heating</td>
<td>Department of Fuels Eng.; University of Utah</td>
<td>Liquid hydrocarbons</td>
<td>Bench scale (Exploratory)</td>
</tr>
<tr>
<td>Liquid Solvent Extraction</td>
<td>British Coal Corp.; Great Britain</td>
<td>Liquefied petroleum gases, naphtha, and middle distillate</td>
<td>2.5 ton/day pilot plant</td>
</tr>
<tr>
<td>NEDOL</td>
<td>New Energy Development Organization; Japan</td>
<td>Naphtha, middle distillates, and (potentially) liquified petroleum gases</td>
<td>1 ton/day PDU; 150 ton/day pilot plant under construction</td>
</tr>
<tr>
<td>Nippon Brown Coal Liquefaction</td>
<td>Nippon Brown Coal Liquefaction Co Ltd.; Japan</td>
<td>Naphtha and middle distillates</td>
<td>50 ton/day pilot plant</td>
</tr>
</tbody>
</table>

SOURCE: DOE

specifically and others based on components that have been demonstrated on a commercial scale but have not been integrated into a complete system.

Specific items where additional R&D activities could prove beneficial include the development of catalysts that are more tolerant to sulfur and to trace elements in the coal, improvement of overall process efficiency, and the development of new catalysts for conversion of synthesis gas to chemicals and liquid fuels that are geared to lower hydrogen-to-carbon monoxide ratios in the synthesis gas. Catalysts development is being supported by the DOE Coal Liquefaction R&D Program, while advanced gasification power systems are a major part of the DOE Surface Coal Gasification R&D Program.

Liquefaction Research Needs

The eight concepts considered in the liquefaction category of coal refineries are directed principally at the production of liquids that can be upgraded into transportation fuels or for use as chemical feedstocks. Some of these concepts also yield liquid fuels for use in electric utility or industrial boilers. The level of current development activities for these concepts ranges from bench-scale tests to demonstration plants.

Additional R&D activities in this category cover several areas. First, additional R&D will better characterize the basic chemical and physical reactions that occur for some concepts. These characterizations should include the influence of coal structure on the liquefaction chemistry. Such characterizations will allow researchers and designers to optimize the concepts to a greater extent than is now possible. Future R&D activities should include techniques to reduce temperature and pressure conditions in the processing steps, the development of catalysts that are less costly and/or longer lasting, the development of improved chemical solubilization methods, and the influence of coal type on operating conditions and product yields. These and related research activities are presently part of the DOE Coal Liquefaction R&D Program.

Bioprocessing Research Needs.

Refinery concepts based on bioprocessing of coal are considerably less developed than most of the concepts considered. The experiments are being performed at a very
small scale and are addressing fundamental issues such as the type of micro-organisms needed, reaction times required, nutrients needed, etc.

Because of the comparatively early stage of development for this category of refineries, there are basic R&D activities that must be undertaken before these concepts can become commercialized. Once additional progress has been made in these areas, R&D activities can include greater detail in concept design, concept economics, product yields, and some of the other more conventional aspects associated with the evolution of an R&D process into a commercial entity.

There are fundamental research activities presently in the DOE Fossil Energy R&D Programs related to bioprocessing coal refineries.

Conclusions

There are several levels of potential R&D for coal refineries. One level is concerned with the basic phenomena or processes that are important to all coal refinery concepts. Areas of R&D that might be important at this level include the basic structure of coal along with its basic reactions with chemicals and reagents or the influence of various catalysts.

A second level of R&D for coal refineries could be more focused toward a general category of concepts. For example, R&D on catalysts may be applicable to several concepts within the liquefaction category, and research on hot-gas cleanup systems may improve the efficiency and environmental features of several concepts in the gasification category.

The third level of R&D activities is addressed to a specific process or concept. This level is reached after the concept has undergone extensive evaluation and experimentation and typically involves a large demonstration-scale, near-commercial facility in which many of the individual components of a concept are integrated into a complete system.

The report concludes that because there are existing R&D activities within DOE at all levels and which are applicable to coal refineries, there appears to be little or no need to establish new R&D programs specifically toward coal refineries but rather to continue to support the necessary R&D within the programmatic structure currently in effect in DOE.

###

CCT ROUND 5 DELAYED

The solicitation date for Round 5 of the United States Department of Energy (DOE) Clean Coal Technology Program has been delayed in a compromise between the House and the Senate. A House-Senate conference committee agreed to push the solicitation date back to July 6, 1992 instead of the original date of March 1, 1992.

Once the Round 5 solicitation goes out, DOE will have 10 months to make final project selections, 2 more months than were allowed in the previous four rounds. Project sponsors will have 5 months to prepare their proposals and DOE will have an extra month to evaluate them and determine project selections.

A proposal requesting a sixth round of solicitations has been dropped, but the conference committee agreed that funding will be provided for a sixth round based on unobligated and unneeded amounts that may become available from the first five rounds.
The Secretary of Energy is required to submit a report on available funds to the House and Senate Committees on Appropriations no later than May 1, 1994. Based on that report, the funding, dates and conditions for the sixth round of solicitations will be included in the fiscal year 1995 appropriation.

Round 5 will be conducted under the same general criteria as the fourth solicitation but will include a wider range of eligible technologies and applications. DOE is expected to adjust technical criteria to consider development activities, strengthen criteria for non-utility demonstrations and adjust commercial performance criteria regarding general energy efficiency and environmental performance.

###

**TWO SBIR GRANTS GIVEN FOR COAL LIQUEFACTION**

The United States Department of Energy, under Phase I of its 1991 Small Business Innovative Research (SBIR) program, has awarded grants for two coal liquefaction technologies. These are 2 of the 173 projects selected for Phase I awards out of 1,401 applications received in response to the ninth annual solicitation.

**In Situ Fourier Transform-Infrared Diagnostic Techniques for Coal Liquefaction Processes**

Advanced Fuel Research, Inc. of East Hartford, Connecticut is the recipient of a $49,954 SBIR grant. For the continued development of coal liquefaction processes, online diagnostic techniques are needed that allow one to observe the various process stages and monitor parameters such as catalyst activity, upgrading of liquids, depletion of solvent, heteroatom removal, etc.

This project is based on two innovations. The first is the application of Fourier Transform-Infrared (FT-IR) diagnostics to the characterization of coal liquefaction process streams. The mid-IR wavelengths (1 to 20 microns) contain a wealth of information about chemical bonds and temperature. The second innovation is the use of Fiber-Optic (F-O) Attenuated Total Reflectance (ATR) spectroscopy. The use of fiber optics allows the transmission of the IR light through a process stream under difficult operating conditions (high temperature and high pressure). ATR spectroscopy makes the analyses of highly absorbing materials, such as liquid hydrocarbon streams, possible by providing a reproducible, short path length.

The Phase I work will demonstrate an FT-IR/F-O/ATR spectroscopy system for online monitoring of coal liquefaction process streams. The work includes four individual tasks:

- Design of a test cell with an F-O/ATR element for the liquid phase
- Demonstration of the test cell to obtain quantitative FT-IR reference spectra for various compounds
- Experiments under coal liquefaction reactor conditions
- Assessment of the Wilsonville, Alabama process development unit (PDU) for online monitoring

The Phase II effort is to demonstrate this technology in a continuous flow system at a selected location at the Wilsonville PDU and will address the following remaining research issues:

- The appropriate sensing element to go inside the reactor
- The best method of dealing with problems such as erosion and deposit formation
- Ways to carry the signal to a remote location
- The possibility from a technical and economic standpoint of multiplexing (measurement at more than one location with the same instrument)

**Anticipated Results**

If carried through Phases II and III, the anticipated result of this research is an instrument package, including software, for online monitoring of coal liquefaction process streams. The research is designed to produce an instrument that has direct application to coal liquefaction process development activities. However, the same instrument may have applications in a much wider market, such as petroleum and petrochemical industries, because the process streams and conditions are similar.

**Bioconversion of Coal Syngas to Fuel Oxygenates**

Engineering Resources, Inc. of Fayetteville, Arkansas received an SBIR grant in the amount of $50,000 for the bioconversion of coal syngas to fuel oxygenates.

Gasoline blended with fuel oxygenates produced from coal has several significant advantages over conventional gasoline, including reduced pollutant emissions, less dependence on imported oil, and increased octane quality. Alcohols and ethers have received primary interest as fuel oxygenates because these materials are available in large quantities. Ketones and diols, very similar to ethers and alcohols in chemical structure and thermodynamic behavior, may be produced biologically from coal synthesis gas and may be su-
perior fuel additives. The purpose of this project is to investigate a simple biocatalytic process to produce ketones and diols from coal synthesis gas.

Biological processes operate at ordinary conditions with low capital and energy requirements. Microorganisms can produce oxygenates from carbon monoxide (CO) and water, as well as from carbon dioxide and hydrogen, and total conversion of coal is possible. Microorganisms are also quite specific in producing a single product, so that high yields from synthesis gas are possible. The major aim of this project is to determine the technical and economic feasibility of biological processes to produce ketones or diols from synthesis gas. In Phase I of this project, cultures are being screened to identify the best organisms for use in continuous reactors to define reaction kinetics and to provide data for economic projections.

Potential Commercial Applications

Reformulated gasolines contain fuel oxygenates to reduce emissions of CO, hydrocarbons, and nitrogen oxides. The demand for these fuel additives is expected to increase rapidly in the near future. Successful completion of this research project could provide a simple biological process to produce oxygenates from coal; substantial incentives exist for the commercialization of this technology.
ENERGY POLICY AND FORECASTS

CERI SEES BIG ROLE FOR IGCC IN CANADA

Worldwide research has led to the development of a range of combustion technologies which mitigate the environmental impacts of burning coal for electric power generation—ambient fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC) and integrated gasification combined cycle (IGCC) technology. Of these technologies, IGCC promises the best combination of economic, efficiency and environmental benefits and has been identified by many electric utilities as the coal-based power generation technology for the 1990s.

According to a study from the Canadian Energy Research Institute (CERI), integrated gasification combined cycle offers a combination of advantages which no other coal-based system can match. IGCC promises short lead-time construction, competitive capital cost, operational and planning flexibility, lower water consumption, small land requirements, and markedly reduced sulfur, nitrogen, particulate and CO$_2$ emissions relative to conventional coal fired power plants.

Ongoing progress in gas turbine technology promises further gains in IGCC efficiency. System improvements stemming from IGCC demonstration projects portend additional improvements in efficiency, lower costs and major reductions in CO$_2$ emissions. Moreover, IGCC affords a unique opportunity for coproducing valuable chemical byproducts.

In Canada, IGCC is under active investigation in Nova Scotia, New Brunswick, Ontario, Saskatchewan and Alberta.

IGCC Application

According to the CERI study, *New Coal Technology and Electric Power Development*, one of the most important characteristics of the IGCC concept is the flexibility this technology provides utility planners in dealing with the uncertainties associated with forecasting and planning for future load growth coupled with uncertain future fuel prices. This flexibility stems from the ability to install the full IGCC facility in a series of steps or phases.

IGCC’s ability to respond quickly to changes in electricity demand with relatively small increments of generating capacity is extremely important, as it enhances planning flexibility by reducing the risk of errors in forecasting future electricity demand.

While IGCC technology is best suited to new power plant applications, it may also be used to repower existing gas, oil or coal fired boilers. An existing plant, at the end of its useful life, can be repowered to have the 30-year lifetime of a new facility.

Integrated gasification combined cycle also affords a unique opportunity for producing valuable byproducts from the gasification of coal, when electricity production is naturally scaled back at night to match low demand periods.

In an IGCC plant, the capacity factor on the gasification section of the plant could be significantly increased if the syngas that could be produced when the power plant was not operating could be converted into a valuable chemical byproduct. This idea of coproducing a number of products at a single facility leads to the concept of an integrated energy facility (see Figure 1 on the next page).

It has been shown that coproduction of electric power and chemicals could result in reductions in the cost of producing electricity that are as high as 33 percent. This type of operation not only increases the value added to both capital equipment and fuel, but also provides a long-term opportunity for diversification and the generation of low cost electric power.

Canadian IGCC Efforts

A major evaluation of IGCC for three sites in Canada—Nova Scotia, Ontario and Alberta—was recently completed by Bechtel Canada Inc. The work was sponsored by the Canadian Electrical Association and was funded by the Government of Ontario, Ontario Hydro, Environment Canada, and members of the Canadian Coal Gasification Technical Committee. Conceptual engineering design, plant performance, the selection of gasification processes, emission projections and capital cost estimation were carried out by Bechtel.

In addition, the need for IGCC demonstration under conditions unique to Canada encouraged the Coal Association of Canada (CAC) to propose the design, construction, and operation of an IGCC demonstration project. The proposed study will address CO$_2$ removal, environmental emissions, site selection, process selection and capital and operating costs.

One of the unique facets of the Coal Association’s proposed IGCC study is the assessment of carbon dioxide recovery and disposal. It is anticipated that over 50 percent of the CO$_2$ could be removed after a water gas shift reaction converts carbon monoxide to CO$_2$. As a result, carbon dioxide emissions would be approximately the same as those resulting from the combustion of natural gas. The CAC contends that CO$_2$ production from a significant percentage of the presently installed coal fired generation in Western Canada could be used for enhanced oil production. However, other means of disposing of CO$_2$, including injection into salt domes or depleted oil and gas reservoirs or into brines or other aquifers, would also be assessed as part of this research.
The province of Saskatchewan is also supporting joint government-industry assessment of the technical and economic feasibility of using IGCC for post-2000 power generation. Saskatchewan is currently considering the testing of a lignite coal in a pilot gasification unit to determine the gasification characteristics of the coal.

Coal Technology Efficiency Gain

Table 1 presents a scenario which assumes that a 10 percent absolute energy efficiency gain is realized over the 1990 to 2010 period for IGCC, PFBC and AFBC technologies. This improvement in efficiency seems realistic given the impressive strides made in gas turbine technology to date, says CERI, and is an accreditation for the kind of overall improve-

---

**TABLE 1**

<table>
<thead>
<tr>
<th></th>
<th>Carbon</th>
<th>Sulfur</th>
<th>Nitrogen</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$10^4$ ton/yr</td>
<td>$10^3$ ton/yr</td>
<td>$10^3$ ton/yr</td>
<td>$10^3$ ton/yr</td>
</tr>
<tr>
<td>Total for 1988 - 2011</td>
<td>3,224.4</td>
<td>18,588</td>
<td>7,692</td>
<td>3,250,680</td>
</tr>
<tr>
<td>Base Case Minus Coal Efficiency Gain Case</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total for 1988 - 2011</td>
<td>124.5</td>
<td>837</td>
<td>651</td>
<td>125,988</td>
</tr>
</tbody>
</table>

Objective Function (million C$1989)$

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>C$1989$/Tonne</td>
<td>1,482</td>
</tr>
<tr>
<td>$11.76$</td>
<td></td>
</tr>
</tbody>
</table>

---

SYNTHETIC FUELS REPORT, DECEMBER 1991
ment expected as a result of wider demonstration of these technologies around the world.

As displayed in the lower half of the table, the net impact of this increase in efficiency means that aggregate emissions from the Canadian electric power sector fall 126 million tons at an incremental savings of C$1.5 billion or C$11.76 per tonne. To reduce emissions to this level, Ontario requires 2.1 gigawatts of selective catalytic reduction, 0.8 gigawatts of flue gas desulfurization and 7.6 gigawatts of IGCC over the 1994-2011 period. Alberta brings on 4.3 gigawatts of IGCC and New Brunswick, Nova Scotia and Prince Edward Island bring on 0.9 gigawatts of flue gas desulfurization, 2.1 gigawatts of IGCC capacity and 0.47 gigawatts of PFBC (see Figure 2).

**FIGURE 2**

CAPACITY ADDED FROM COAL TECHNOLOGY EFFICIENCY IMPROVEMENT BY 2009

SOURCE: CERI

Recommendations

The CERI study makes a number of recommendations, some of which are listed below.

Research and development of clean coal technologies for use in Canadian electric power production should be increased and export of Canadian clean coal technology to developing countries should be evaluated.

Electric utilities should be allowed to include demand-side programs and competitive bidding programs into utility rate base.

Public utilities boards’ regulatory powers should be changed to recognize energy efficiency in electricity production and use, not simply rates and rate structures.

Canadian public and government spokesmen must recognize the strategic importance of coal to fueling the electric power needs of Canadian business, industry and residences. Coal constitutes over 80 percent of Canada’s remaining fossil fuel reserves; coal can be used cleanly; and the price of coal is directly tied to the cost of production not to geopolitical events.

Significantly more research and development funding support should go to research, development and demonstration of integrated energy efficiency programs which include burnable waste for energy.

The use of IGCC burning coal and sewage sludge, akin to plans for the Cool Water Plant in California, should be seriously evaluated by Canadian energy/environment policy makers—an integrated approach to energy and environment is mandatory.

####

SYNTHETIC FUELS REPORT, DECEMBER 1991
MILD GASIFICATION TO PRODUCE FORMCOKE IN PENNSYLVANIA SHOWS PROMISE

A project to evaluate the integration of a mild gasification process (MGP) within an existing power station shows that the arrangement could be a very attractive commercial venture.

The owners of the Homer City Power Station in central Pennsylvania were interested in the potential for utilizing fine coal in the MGP. The power station is owned by Pennsylvania Electric Company and New York State Electric and Gas Company.

Researchers at the Morgantown Energy Technology Center (METC), United States Department of Energy, have been developing technology to produce value added products from coal using mild gasification technology. MGP thermally distills coal at relatively low temperatures, producing valuable coal liquids and a char which can be further processed to metallurgical grade coke. METC was interested in reducing the capital and operating costs of MGP by using a power station infrastructure.

MGP Market Potential

The production of coke from coal using the MGP technology coupled with formcoke production offers great potential. No new domestic coke ovens are planned.

The steel industry is seeking to extend the existing supply of domestic coke by the use of new carbon sources. Alternatives to high temperature coke, used as chemical carbon and carbon as fuel, are being sought. The MGP technology coupled with the production of formcoke is an attractive source of carbon for both fuel and chemical reduction of ore.

MGP technology provides three principal products which have significant commercial value: char, light oil and heavy oil. In addition, combustible gas is available for heating. For the cases evaluated in the study, these products have a value ranging from $42.62 to $138 per ton of feed coal. The value of formcoke was varied from $75 to $200 per ton.

The study results indicate that the installation of an MGP at an existing power station will result in significant capital and operating cost savings as compared to a greenfield MGP installation. The resulting savings will allow the production of formcoke for metallurgical purposes at commercially competitive prices with significant internal rates of return.

Homer City Site

The Homer City site includes a 1,200 ton per hour coal preparation plant, coal handling and storage facilities, 1,850 megawatts of power production, fly ash disposal site, and a coal refuse disposal site.

The coal preparation plant produces on the average 100 tons per hour of uncleaned minus 100 mesh coal. The presence of fines in both the cleaning plant product and the fuel supply to the power generating station, however, results in several major operating problems.

The coal supplied to the power station must have 7 percent or less moisture. Consequently, and primarily because of the minus 100 mesh coal, both the middling and deep cleaned coal are thermally dried. This represents a significant operating and maintenance cost.

Case Studies

For the economic evaluation of the capital and operating costs, four MGP cases were evaluated. These are:

- Greenfield site: Construction of MGP at a new non-utility site
- Case 1: Integration of MGP at the utility site, including all modifications required to produce and handle char, formcoke, coal liquids and gases
- Case 2: Same as Case 1 but utilization of coal liquids and gases as fuel for power production
- Case 3: Same as Case 1 but utilization of existing coarse coal supply and eliminating the need for oil agglomeration as a drying step

Economic Analysis

Each of the four cases was evaluated using a capital cost model, an operating cost model and an internal rate of return (IRR) model. The initial investment is 100 percent of capital requirements. The basis for the economic evaluation includes use of utility financial criteria as follows:

- Discount factor - 10.7 percent
- Interest on debt - 12 percent
- Corporate tax rate - 39.61 percent
- Depreciation, straight-line - 20 years
- Term of loan - 20 years
- Escalation rate - 4 percent

The integrated MGP plant is designed to receive fine coal 48 weeks per year, 5 days per week, 24 hours per day. A second capacity case involves operation of the plant for 7 days per week using on-site coal as additional feed to the MGP. Overall plant capacity is 2,400 tons per day of feed.
The preliminary economic analysis indicated that the char formed in the MGP process is not an economic fuel for the utility company. For this reason, the economic analysis is based on production and sale of formcoke.

The utility expects a positive IRR in 5 years or less to justify a project.

The capital investment and operating costs for the four cases are summarized in Table 1.

### TABLE 1

**CAPITAL AND OPERATING COSTS OF STUDY CASES**

(Millions of Dollars)

<table>
<thead>
<tr>
<th>Case</th>
<th>Capital Investment</th>
<th>Annual Operating Cost</th>
<th>High</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greenfield</td>
<td>200.8</td>
<td></td>
<td>64.1</td>
<td>48.1</td>
</tr>
<tr>
<td>Case 1</td>
<td>188.3</td>
<td></td>
<td>62.6</td>
<td>46.9</td>
</tr>
<tr>
<td>Case 2</td>
<td>177.5</td>
<td></td>
<td>61.1</td>
<td>45.7</td>
</tr>
<tr>
<td>Case 3</td>
<td>107.8</td>
<td></td>
<td>52.2</td>
<td>38.3</td>
</tr>
</tbody>
</table>

(Annual operating cost includes coal cost of $35 per ton.)

A more detailed summary of the capital investment for two of cases is shown in Table 2. The economic analysis is summarized in Table 3, on the next page.

For the Greenfield case, with an installed capital cost of $200.8 million and an annual operating cost of $48.1 million at the 66 percent capacity factor and $64.1 million at the 92 percent capacity factor, economic viability occurs only when a high plant capacity factor is achieved and only at a high value of formcoke ($200 per ton). The IRR is 10 percent. The positive IRR occurs in 9.5 years.

In Case 1, the capital investment is reduced to $188.3 million and the operating costs are reduced to $46.9 and $62.6 million, respectively. The plant realizes $5.5 million in annual savings due to elimination of coal fines.

For the high capacity factor case, positive IRR is achieved at formcoke values in excess of $125 per ton. In Case 1 utility economic justification for new projects are not met at any formcoke value; however, at $200 per ton, positive IRR is achieved in 6 years.

Case 2 represents a less intensive capital requirement to integrating the MGP into the utility site. The capital savings realized by eliminating the recovery of liquids and gases and utilizing these products in a hot condition as fuel are evaluated in terms of power generated. This value is the utility's avoided cost value of $0.027 per kilowatt-hour.
TABLE 3
SUMMARY OF ECONOMIC ANALYSES
MINIMUM CONDITIONS FOR MEETING
UTILITY ECONOMIC CRITERIA

<table>
<thead>
<tr>
<th>Case</th>
<th>Form Coke</th>
<th>Capacity</th>
<th>Year</th>
<th>IRR, %</th>
<th>Meets Utility Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greenfield</td>
<td>200</td>
<td>92</td>
<td>9</td>
<td>10</td>
<td>No</td>
</tr>
<tr>
<td>Case 1</td>
<td>200</td>
<td>92</td>
<td>6</td>
<td>18</td>
<td>No</td>
</tr>
<tr>
<td>Case 2</td>
<td>200</td>
<td>92</td>
<td>5.5</td>
<td>20</td>
<td>No</td>
</tr>
<tr>
<td>Case 3</td>
<td>110</td>
<td>92</td>
<td>5</td>
<td>25</td>
<td>Yes</td>
</tr>
</tbody>
</table>

ECONOMIC IMPACT OF COAL IN CANADA ASSESSED

The Canadian Energy Research Institute (CERI) recently published a study assessing the economic impact of mining, processing, transportation and consumption of coal in Canada. Coal in Canada, by K.M. MacRae and S. Hatch, reviews the history and current status of Canada's coal industry and analyzes the widespread economic impact of the coal industry on the domestic economy.

According to the report, there are three principal reasons for the strategic and economic importance of Canadian coal to the national economy:

- Canada has large reserves of thermal and metallurgical coals
- Many regions in Canada depend on coal for electric power generation
- Canadian coal production and exports generate significant employment in mining, manufacturing, and transportation across Canada

Canada has about 6.5 billion tonnes of proven recoverable reserves of coal—about 100 years of supply at current Canadian production levels. Coal-fired electricity generation accounts for over 85 percent of total Canadian consumption of coal.

The Canadian coal industry has both direct and indirect effects on the national economy. The direct effects result from the purchase of goods and services required to produce coal and the income generated as a result of coal output. The indirect effects derive from the linkages between the coal industry and the rest of the economy, and the input requirements and income generated in those industries required to support the production of coal.

To analyze the various types of linkages and indirect effects of Canada's coal industry, the Statistics Canada (1987) commodity by industry input-output table was used to provide estimates of the effect that coal production and related activities have on total Canadian employment and income.

Aside from the impacts related to rail and port transportation, the indirect impacts associated with forward linkages of coal production (e.g., electric power generation) were not estimated in the study due to data limitations. Because coal-fired electric power generation is important in Saskatchewan, Ontario, Alberta and Nova Scotia, these employment effects may be significant.

Economic Impact: Port and Rail Systems

The movement of coal through Canadian ports creates jobs for individuals directly involved in the handling of coal at the ports. Additional jobs are created in the transportation of coal by railway. The wages and salaries collected by individuals with jobs directly created by coal transport can be described as an income impact, which may be adjusted to reflect the level of respending throughout the provincial and national economies.

According to a Ports Canada System study, movements of coal created 0.09 jobs per 1,000 tonnes handled at ports, and for every direct job created by port activity, another 0.7 jobs were induced throughout the provincial and national economies. Additional indirect jobs are created due to purchases by firms supplying maritime and transportation services.
Summing across all port facilities, the roughly 35 million tonnes of coal transported by railways and loaded at ports created about 3,200 direct jobs, 1,180 indirect jobs, and 2,340 induced jobs for a total estimate of 6,720 transportation jobs nationwide in 1989 (Figure 1).

![Figure 1](image)

The estimated total personal income generated from the handling and transportation of domestic coal production in 1989 was of the order of $290 million.

The estimated total revenue accruing to firms directly involved in the railway transportation and port handling of domestic coal production in 1989 was of the order of $887 million throughout Canada's economy.

**Economic Impact: National Economy**

From the Statistics Canada National Input-Output model, an employment multiplier of 1.62 was calculated. That is, for each person directly employed in the production of coal, 0.62 indirect jobs were also created in the rest of the economy to support the production of coal. In 1989, the total number of employees involved in Canadian coal mining activity was 11,239. Applying the employment multiplier of 1.62 yields an estimate of total direct and indirect jobs supported by Canadian coal mining activity of 18,208 jobs in 1989. While coal production has a broad-based impact on many industries in Canada, the majority of the impact is felt in industries such as wholesale and retail trade, the business service industries and rail transportation and related services. Figure 2 (on the next page) depicts the employment impact of coal production on selected major industries in Canada.

Consumer expenditures by persons directly employed in the coal mining industry generate additional induced employment. Using an induced employment multiplier, direct coal industry employment induces an additional 7,867 jobs throughout Canada for a total direct, indirect and induced employment impact of 26,075.

Adding the employment resulting from port and railway movements of coal, the estimate of total employment generated across Canada by coal production and transportation in 1989 is 32,795. Thus, every job in the coal industry generates an additional 1.92 jobs in the economy. However, this estimate does not account for those employed in coal-related consulting firms, or those employed by the federal and provincial governments in coal policy, research and development.

The direct and indirect value-added from the activity of coal mining industries supports an income multiplier of 1.487. That is, for each dollar of value-added in Canada's coal mining industry, another $0.487 is generated in the economy.

Including consumer expenditures of those directly employed in the coal industry, the income multiplier is calculated as 2.38. That is, for every dollar of value-added income in the coal industry, another $1.38 of indirect and induced income is generated in the Canadian economy. In 1989, total value-added in Canada's coal industry was $1.2 billion. It follows then that the total value-added to the Canadian economy from coal industry activity was $2.9 billion in 1989. Adding personal income generated in port and rail activity associated with coal transportation brings this total to almost $3.2 billion for 1989.
FIGURE 2

EMPLOYMENT IMPACT OF COAL PRODUCTION IN CANADA

Electric Power Sys. 3.7%  Rail Transportation 6%
Repair Construction 3.8%
Chemical Products 4.5%
Other Mach. & Equip. 3.3%
Business Services 11%
Wholesale Trade 19%
Retail Trade 6.4%
Banks, Finance 6.8%
Insurance 4.9%

SOURCE: CERI
ENCOAL SOLID PRODUCT SHOWS FAVORABLE
COMBUSTION PROPERTIES

The solid process derived fuel (PDF) obtained from the liquids from coal (LFC) process has desirable handling, storage, combustion and ash utilization properties. Based on these properties, a demonstration plant, now under construction, will begin production in 1992 on a scale sufficient for full scale utility test burns.

ENCOAL Corporation, under the Clean Coal Technology Program, will operate a 1,000 ton per day mild gasification demonstration plant at the Buckskin Mine near Gillette, Wyoming. The demonstration plant will utilize LFC technology developed by Shell Mining Company and SGI International of La Jolla, California. The demonstration plant, using Powder River Basin (PRB) coals as feedstock, will produce 500 tons per day of a low sulfur solid fuel and 500 barrels per day of a low sulfur liquid fuel.

A paper presented by T.G. McCord, ENCOAL Corporation, et al., at the 16th Low Rank Fuels Symposium held in Billings, Montana in May focuses on the properties of the solid product generated in the LFC process. The products retain 90 percent of the feed coal’s heating value.

In the LFC process, coal from the Buckskin Mine is screened to remove fines. The resulting 2 inch by 1/8 inch coal is dried in a rotary grate dryer and fed to a pyrolyzer where the solids are mildly pyrolyzed. Solids from the pyrolyzer are cooled and stabilized. Gases released during pyrolysis are cooled to condense the liquid product and the residual gases are burned.

Product Analysis

The solid product is called process derived fuel. A comparison of the properties of PDF with the Buckskin feed coal is given in Table 1. Heating value increases both on an as-received basis and on a moisture and ash-free basis. This latter increase, from 12,800 to 14,100 BTU per pound is due to chemical changes occurring during pyrolysis. Sulfur content decreases slightly, which may be more significant when the LFC process is used with higher sulfur coals from regions outside the Powder River Basin. Water content is reduced from 30 percent to about 4 percent.

Because the ash stays with the solid and about 1 ton of product is generated for 2 tons of feed, the ash percentage doubles. On a pound per million BTU basis the increase is much smaller, from 6.0 to 8.3 pounds of ash per million BTU. Because of the increased efficiency of burning PDF compared to its parent PRB coal, the amount of ash generated on a pound per kilowatt-hour basis for PDF is only about 30 percent more than from the parent PRB coal. The volatiles content decreases significantly. Ash fusion temperatures are the same as for the parent feed coal.

<table>
<thead>
<tr>
<th>Feed Coal</th>
<th>PDF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heating Value (BTU/lb)</td>
<td>8,300</td>
</tr>
<tr>
<td>SO₂ (lb/MMBTU)</td>
<td>1.2</td>
</tr>
<tr>
<td>H₂O (Wt%)</td>
<td>30</td>
</tr>
<tr>
<td>Ash (Wt%)</td>
<td>5</td>
</tr>
<tr>
<td>Volatiles (Wt%)</td>
<td>29</td>
</tr>
<tr>
<td>Fixed Carbon (Wt%)</td>
<td>36</td>
</tr>
<tr>
<td>Sulfur (Wt%)</td>
<td>0.50</td>
</tr>
<tr>
<td>Ash Fusion Temp. (°F)</td>
<td>2,220</td>
</tr>
</tbody>
</table>

Moisture Resorption

Once moisture has been removed from PRB coal there is the question of whether the dried product will resorb moisture and return to its original state. Only a small amount of water would naturally resorb into PDF. Two factors contribute to this tendency, one physical and one chemical. Some of the pores collapse, thereby physically preventing re-entry of water.

In addition, when PRB coal is subjected to LFC pyrolysis conditions, the oxygen content, on a dry ash-free basis, is reduced by approximately 50 percent. With less oxygen and therefore fewer polar oxygenated sites, the PDF is more hydrophobic, inhibiting the sorption of polar water molecules. Thus moisture resorption from humid air will not cause PDF to regain the high moisture levels of its parent feed coal.

Spontaneous Combustion

For spontaneous combustion to occur in a stockpile, oxygen must come in contact with the coal and then react with it. If there is insufficient heat transfer to the surroundings, the heat released by the coal-oxygen reaction raises the temperature of the coal and leads to spontaneous ignition problems as manifested by a smoldering or hot stockpile. If the spontaneous ignition tendency is assumed to be proportional to the reaction rate with oxygen, all other factors being equal, then measuring the reaction rate with oxygen can be used to estimate relative performance.

The rate for oxygen consumption for PDF is only about one-half the rate for the parent PRB coal. Because the rate at
which oxygen reacts with PDF is significantly less than with the parent PRB coal, the tendency for spontaneous combustion is predicted to be reduced also.

Combustion Temperature Reactivity

The most significant difference between PDF and most other coals that are used for raising steam is the lower volatiles content of PDF. The most frequently specified minimum volatiles content is 25 percent. However, this specification is based on bituminous coals. Therefore, it was necessary to determine combustibility and reactivity of this new type of solid fuel, a subbituminous-based product having about 19 percent volatiles.

A preliminary evaluation of the combustibility characteristics of PDF was carried out in a 600,000 BTU per hour pilot test facility. Key properties examined included PDF flame visual appearance, stability at the burner, and completeness of combustion.

In general, the stability characteristics of PDF appeared to be quite good and were comparable to the parent PRB coal. Problems that would be associated with poor flame stability were not encountered.

Data on carbon monoxide levels and carbon burnout are shown in Table 2. Two types of PDF were tested, one with a volatiles content lower than the projected 19 percent for the commercial PDF product, and the other higher. Also, tests were run at two furnace exit gas temperatures. As shown in Table 2, the carbon monoxide levels for PDF were only slightly higher than the parent PRB coal, and there was little variation in carbon monoxide emissions between the two furnace exit gas temperature conditions tested. The carbon monoxide levels generated by PDF were less than many bituminous coals tested under the same conditions.

Carbon burnout for PDF, at all conditions tested, was comparable to the parent PRB coal. PDF carbon burnout levels (99 percent plus) were also higher than those observed for a number of bituminous coals tested under the same conditions.

According to the paper, the high reactivity of PDF may be due to its structure at flame temperature compared to bituminous coals. Subbituminous coal does not agglomerate, thus retaining the high surface area.

Ash Deposition

In the LFC process, essentially all the ash remains with the solids. Testing has verified the prediction of similar ash deposition characteristics between PDF and its parent PRB coal, for the most part. The one difference was that superheater deposits for PDF were significantly more brittle than those of the parent PRB coal, thus making removal by sootblowing easier.

Successful test burns of PRB coals, both unblended as well as blended with Eastern coals, have been reported recently in steam generators designed for bituminous coals. Thus, it is anticipated that PDF will be compatible with steam generators designed for Eastern coals with respect to ash deposition.

The high calcium content of the PRB ash produces a significantly different deposition pattern than the high iron content in the ash of Eastern coals. Furnace waterwall deposits for ash from PRB coals from the Gillette area are thin and easily blown off the walls.

<table>
<thead>
<tr>
<th>TABLE 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>LABORATORY COMBUSTION TESTS</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Volatiles (%)</th>
<th>FEGT* (°F)</th>
<th>Carbon Monoxide (PPM)</th>
<th>Carbon Burnout (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Higher FEGT Range</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Parent Coal</td>
<td>34</td>
<td>2160</td>
<td>18</td>
</tr>
<tr>
<td>PDF, Higher Vol.</td>
<td>22</td>
<td>2150</td>
<td>25</td>
</tr>
<tr>
<td>PDF, Lower Vol.</td>
<td>17</td>
<td>2200</td>
<td>27</td>
</tr>
<tr>
<td>Lower FEGT Range</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PDF, Higher Vol.</td>
<td>22</td>
<td>2030</td>
<td>25</td>
</tr>
<tr>
<td>PDF, Lower Vol.</td>
<td>17</td>
<td>2060</td>
<td>32</td>
</tr>
</tbody>
</table>

*Furnace Exit Gas Temperature
Backpass fouling, which is heavier with PRB coals than with most Eastern coals, will be a site specific factor depending on tube spacing and sootblower coverage. Backpass fouling on operation with PDF will vary and be studied on a case by case basis. The increased brittleness of PDF superheater deposits could be a positive factor in reducing convection section fouling.

Flyash Collection and Utilization

There are no differences between PDF and the parent PRB coal in the area of flyash collection and utilization. Power plants that have cold side electrostatic precipitators designed for higher sulfur coals have several potential avenues to maintain efficiency when switching to low sulfur coals. One of these options, SO\textsubscript{3} conditioning, can be used with the high calcium ash in PDF generated from PRB coal.

###

**VOXTE FLUIDIZED BED GASIFIER UNDER DEVELOPMENT**

The York-Shipley Division of DONLEE Technologies Inc. in York, Pennsylvania has been working on a project to develop an advanced substoichiometric pre-combustor for removing sulfur by sorbent injection and producing a combustible gas. This concept is based on an advanced Vortex fluidized bed combustion (VFBC) technology in which a portion of the combustion air is introduced tangentially into the hot cyclone. A 4 million BTU per hour laboratory unit was utilized to evaluate the performance and operating limits of the concept.

Results of the testing were presented at the Gasification Contractors' Coordination Meeting held in Morgantown, West Virginia in August.

The Vortex fluidized bed concept was developed to reduce the size of the combustor and the front-end costs of current circulating fluidized bed combustor technologies, while incorporating their desirable features of fuel flexibility, high combustion efficiency, and improved sulfur capture and sorbent utilization.

Heat transfer tubes immersed in bubbling beds can be up to five times more effective than those installed in a circulating fluidized bed freeboard. In addition to the substantial reduction of heat transfer surface required, the use of a bubbling adjacent cooling bed will allow a substantial reduction in combustor height.

To maintain combustion efficiency with this reduced combustor height, the combustion intensity must be increased. This is accomplished by using the cyclone as a combustor in addition to it being used as a particle capture device.

The high heat capacity of solids circulating between the fluidized bed and the cyclone moderates the temperature differential between these two components. The temperature differential depends upon the rate of solids circulation and the heat released within the vortex. As much as 75 percent of the total combustor heat release can occur within the vortex while maintaining a temperature differential of only 130°F.

The primary advantage of the VFBC, compared with other circulating fluidized beds, is reduced cost due to reduction in combustor and cyclone size. The circulating fluidized bed (CFB) in the VFBC can be approximately one-fourth the cross-sectional area of a typical CFB system of the same capacity. Furthermore, elimination of freeboard heat transfer surface results in a dramatic reduction in combustor height. The VFBC combustor height can be as small as one-fourth the height of a typical CFB of similar capacity.

**Project Description**

The VFBC technology is readily adaptable for operation as a gasifier. In fact the equipment is simplified by the removal of the cooling bed. As a gasifier, the Vortex technology provides the first stage in a two-stage combustion process. It operates substoichiometrically and provides a combustible gas and char. Combustion in a second stage could be a gas burner in a conventional boiler operating at atmospheric pressure, or a topping combustor in an integrated gasification combined cycle (IGCC) operating at high pressure (150 to 300 psig).

This two-stage approach, using Vortex fluidized bed technology to minimize the first-stage combustor size is called 2VFBC combustion. A diagram of the concept is shown in Figure 1, on the next page.

Coal or coal water fuel (CWF) is fed into the fluidizing bed, operating in a circulating fluidized bed regime, where coal devolatilizes and is partially gasified. About 50 percent of the total air (approximately 25 percent of the stoichiometric air) is used in this portion of the 2VFBC.

Limestone is injected dry, or with the CWF, into the bed where it reacts with sulfur volatilized from the coal. Because the atmosphere is reducing, calcium sulfide is the probable product of the sulfur capturing reactions. The balance of the first-stage air is injected into the hot cyclone of the unit. This air is injected tangentially into the cyclone barrel to complete the conversion of carbon.

The first task of this project involved theoretical investigation to verify the technical and economic feasibility of the 2VFBC concept for both new equipment and for retrofit of existing boilers. Based upon heat and material balances and design parameters, the 2VFBC concept seems technically feasible for industrial and larger sized systems. In new applications, the 2VFBC system appears least expensive when
The second task of this project was laboratory-scale experimentation to define the operational and performance parameters of the 2VFBC concept.

Test Equipment

The 2VFBC experimental unit was constructed and delivered to the Penn State University Combustion Laboratory in July 1989. Auxiliary systems to feed slurry and burn the 2VFBC fuel gas were available at the site.

The 2VFBC combustor includes a 1 foot inside diameter freeboard section and a 1 foot inside diameter cyclone. The experimental unit was designed for flexibility; it can accept CWF or dry coal feed.

The 2VFBC laboratory unit has been integrated with a 2 million BTU per hour watertube boiler in order to combust the fuel gas and entrained particulates exiting the cyclone. In order to assure complete combustion of the fuel gas and unburned carbon, the natural gas burner at the front of the boiler is maintained at low fire during testing.

Results

The 2VFBC was operated as a substoichiometric combustor, and a series of tests were conducted to define the operational and performance limits of the precombustor concept.

The research was designed to answer the following questions that have significant impact on the concept's overall performance:

- What carbon conversion can be achieved at substoichiometric conditions?
- What forms of sulfur exist in the solids discharge from the 2VFBC?

The 2VFBC operating temperature was expected to be within a range of 1,500 to 1,800°F. At the upper end of this range, carbon conversion to carbon monoxide and hydrogen by reaction with water vapor begins to become significant. Sulfur capture was expected to be effective at relatively high temperatures (up to 1,800°F) because the environment is reducing. The target sulfur capture for these tests was at least 70 percent. Limestone was injected into the 2VFBC with the CWF and the effect of the Ca/S ratio on sulfur capture was investigated.

Preliminary results for the 10 test runs are given in Table 1, on the next page. A detailed data analysis has yet to be completed but observations can be made as follows.

Sulfur capture is very good with values ranging from 84 to 98 percent. However, the relative proportion of CaS and CaSO₄ in both the solids withdrawn from the gasifier and the solids carried over in the product gas has yet to be determined. Also, the SO₂ content of the flue gas after second stage combustion needs to be predicted.

There is essentially no difference in sulfur capture with or without vortex air.

In general, the carbon conversion was higher than expected with values up to 98 percent. The carbon conversion with vortex air (tests 8 through 10) is significantly higher than without vortex air (tests 1 through 7). It appears that a conversion of about 92 percent can be achieved with vortex air and an operating temperature of less than 1,800°F.

With vortex air there is an increase in product gas heating value that corresponds to the increased carbon conversion.

Future Work

Following data reduction and analysis, design recommendations for a proof-of-concept facility will be made. This will
### Table 1

**Preliminary Test Results**

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Temp. (°F)</th>
<th>Carbon Capture (%)</th>
<th>Carbon Conversion (%)</th>
<th>HHV (BTU/SCF)</th>
<th>Ca/S Molar Ratio</th>
<th>Stoichiometric Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1,688</td>
<td>92.1</td>
<td>58.8</td>
<td>39.7</td>
<td>2.5</td>
<td>0.43</td>
</tr>
<tr>
<td>2</td>
<td>1,684</td>
<td>90.8</td>
<td>56.2</td>
<td>71.3</td>
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<td>0.43</td>
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<td>3</td>
<td>1,788</td>
<td>91.7</td>
<td>62.4</td>
<td>34.2</td>
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<td>0.53</td>
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<tr>
<td>4</td>
<td>1,859</td>
<td>84.7</td>
<td>81.6</td>
<td>42.2</td>
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<td>0.52</td>
</tr>
<tr>
<td>5</td>
<td>1,681</td>
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<td>6</td>
<td>1,683</td>
<td>92.2</td>
<td>55.3</td>
<td>41.9</td>
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<td>7</td>
<td>1,680</td>
<td>96.1</td>
<td>83.4</td>
<td>64.2</td>
<td>4.3</td>
<td>0.46</td>
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<tr>
<td>8</td>
<td>1,776</td>
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<td>76.8</td>
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<td>9</td>
<td>1,748</td>
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<td>10</td>
<td>1,748</td>
<td>84.8</td>
<td>91.2</td>
<td>63.0</td>
<td>2.5</td>
<td>0.51</td>
</tr>
</tbody>
</table>

The above work will be primarily based on using the 2VFBC concept as a retrofit coal combustor for oil, gas or coal fired boilers. However, the performance to date, together with lower capital cost because of the high intensity of the reactions, indicates that the technology is also suitable for advanced integrated gasification combined cycles.

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**Advantages Seen for COREX Process**

Development of the COREX process began in 1980 through a joint venture of the German and Austrian governments. The process has demonstrated an ability to handle a wide range of coals and ores and has developed from a 60,000 ton per year pilot plant to a 360,000 ton per year small scale commercial unit.

ISCOR, a South African steel company, contracted with Deutsche Voest Alpine Industrialanlagenbau (DVAI) in 1985 to build this first small-scale commercial COREX. The unit was commissioned in November 1989, and has operated successfully with non-coking coals and high alkali ores.

Geneva Steel has carefully analyzed various means to reduce emissions while increasing productivity. A team of Geneva's engineers and operators studied a wide range of alternative processes to determine the most viable and environmentally acceptable means of increasing steel production. The study showed the COREX process as the most economical means to attain Geneva's long-term production goals.

A basic flowsheet of the COREX process, for a plant without gas recycling, is shown in Figure 1 on the next page.

**DVAI's Claims**

DVAI claims that operation of the ISCOR unit and the pilot plant have demonstrated the following:

- A 25 to 35 percent operations cost advantage over coke plant/blast furnace ironmaking
- A lower cost than coke plant/blast furnace ironmaking
- The ability to utilize increased quantities of high alkali ores
- The ability to exclusively use non-coking coals for ironmaking
- The ability to eliminate coke plant pollution
- Greater operational flexibility
The ability of COREX offgas to replace natural gas in soaking pits, reheating furnaces, and general plant usage.

Geneva's Analysis

Geneva has analyzed the COREX process to assess the validity of DVAI's claims while also determining the compatibility of the process with Geneva's modernization. Geneva's review of the process has included plant visits, meetings with DVAI and Voest Alpine (joint owners of the technology), extensive in-house analysis, and capital cost studies with a major engineering and construction company. Geneva has concluded that COREX is a viable process and is more adaptable to a wider range of raw materials than the conventional coke plant/blast furnace process.

Cost Effectiveness

A comparison of eight scenarios showed that COREX could be the best option for Geneva. The cost of each scenario was projected over an operating period of 10 years, and included increases in product demand and optimization of coke, iron, and steel production. The eight scenarios are as follows:

- 1 and 2: Optimization of blast furnace production combined with new coke making facilities
- 3 and 4: Implementation of COREX combined with increased fuel and oxygen injection to the blast furnace
- 5 and 6: Coke charging to the Q-BOP for increased scrap usage
- 7 and 8: Utilization of the open hearths to produce artificial hot metal

Odd numbered scenarios use natural gas injection on the blast furnace, while even numbered scenarios use coal injection.

The cost projections indicated that the COREX scenarios No. 3 and 4 were the lowest in cost.
Raw Materials

The COREX process provides a means of increasing the use of low cost Western ores that have high levels of alkalies. DVAI has analyzed and tested Geneva’s iron ore and a range of candidate Western coals and concluded that both can be used in the COREX.

Alkali Ores

DVAI says that increased levels of high alkali iron ores can be used in the COREX process because the sponge iron produced in the reduction shaft is rapidly melted in the high temperature fluidized bed. During this meltdown, DVAI says the alkalies associated with the iron ore are transferred unreduced into the slag. The alkali in the gas will be removed by the cooling gas circuit. The reducing gases entering the reduction shaft are cooled from around 1,900 to 1,550°F by a side stream of 200°F cooled gas. In cooling the side stream of gas, the alkali is condensed out. Because this side stream consists of approximately 20 percent of the reducing gas flow, DVAI claims it restricts the alkali buildup to no more than five times the input value.

Western Coals

DVAI has substantiated that non-coking coals can be used in the COREX process. The determination as to whether a coal is suitable for COREX is based on its heat release capacity under the reducing conditions of the melter/gasifier and on its physical properties after devolatilization. The level of heat release can be assessed through reference charts developed by DVAI which indicate the heat release of the coals by plotting the volatiles on a dry, ash free basis against the ash content and by determining the adiabatic flame temperature from a plot of atomic ratios. The physical properties of the coal/char are presently tested by only DVAI. Several Western coals have been accepted for the COREX process.

Emissions

By eliminating the need for coke, the COREX process eliminates the air, water, and solid-waste discharges associated with coke making. This significantly reduces the emissions, effluents and wastes per unit of iron produced. Table 1 contains data developed by DVAI comparing the emission levels of a typical European steel plant with that of COREX.

Energy Savings

The thermal efficiency of the COREX process is 9 percent higher than a conventional coke oven/blast furnace. The higher efficiency of COREX is primarily attributable to its being a single self-contained process, which effectively retains and utilizes the bulk of the heat generated. In a conventional two-staged coke plant/blast furnace, the heat contained in the pushed coke is lost in quenching. This heat loss represents approximately 7 percent of the heat input to the coke plant/blast furnace.

###

**TABLE 1**

<table>
<thead>
<tr>
<th>Air Emissions</th>
<th>Conventional Process</th>
<th>COREX Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO$_2$</td>
<td>6.6</td>
<td>0.5</td>
</tr>
<tr>
<td>NO$_2$</td>
<td>2.4</td>
<td>0.046</td>
</tr>
<tr>
<td>Particulates</td>
<td>4.2</td>
<td>0.036</td>
</tr>
</tbody>
</table>

Source: DVAI

Cost Savings

For comparative greenfield installations with capacities of 2,200 tons per day of hot metal, the capital costs and production costs of the COREX process are estimated to be some 25 to 35 percent lower.

Operational Flexibility

A major advantage of the COREX process is its production flexibility and the ability for a quick, inexpensive shutdown. Raw material inputs can be controlled to meet either required production levels or iron quality. The slag basicity can be changed from tap-to-tap by adding fluxes or silicon to the coal feed. The COREX unit, or stages of the unit, can be inexpensively shutdown through control of the coal, the sponge iron feeders, or the oxygen supply. DVAI claims the unit can be stopped in 30 minutes and restarted in 4 hours.

COREX Export Gas

The export gas can be utilized for the majority of inplant uses. Computations using Western coals show that 26 billion BTU per day of 223 BTU per standard cubic foot export gas is produced from a 2,200 ton per day COREX unit. The adiabatic flame temperature of this gas at 3,241°F is closer to natural gas, at 3,525°F than blast furnace gas at 2,650°F. This comparison and ISCOR's use of the gas for all inplant usages confirms its ability to replace natural gas.

SYNTHETIC FUELS REPORT, DECEMBER 1991
DIRECT COAL-FIRED GAS TURBINE TESTED

Combustion turbines have historically been limited to burning "clean" fuels such as natural gas and oil. Now, for the first time, a modern turbine has run successfully with direct coal-firing.

In the process, a new technology has emerged that could offer a way to reduce smog-forming pollutants from future turbine power stations, regardless of the fuel used.

The United States Department of Energy (DOE) announced that the Allison Gas Turbine Division of General Motors Corporation successfully tested a 4-megawatt gas turbine fueled by a finely ground coal and water mixture. This is the first known test in which a modern turbine ran long enough without damage to verify that coal firing is a realistic possibility.

Past attempts have failed because tiny ash particles from the coal eroded turbine blades or plugged gas flow passages. In some tests, turbine operations had to be halted after only 15 minutes. Allison ran its tests for 4 hours, the planned duration, with no ill effects.

The test run took place at the company's Indianapolis, Indiana plant in August as part of a cost-shared DOE contract. DOE made the announcement after completing its review of test data. The data showed that complete and stable combustion of the fuel occurred and the turbine performed as designed.

The innovation is a low-NO\textsubscript{x} combustion system that Allison has named the "rich, quench, lean," or RQL technology.

The system is a three-stage, high pressure combustion process. Coal is first burned at very high temperatures (about 1,820°C or 3,000°F) in a fuel-rich zone with a limited amount of air. The coal is only partially burned, and there is not enough time nor oxygen for nitrogen to combine with air to form large quantities of NO\textsubscript{x}.

The fuel-rich gases are then doused with water in the "quench" zone, essentially "freezing" their low amount of NO\textsubscript{x}. Quenching lowers the temperature and solidifies coal ash so it can be removed before harming the turbine. Combustion is then completed in a third, fuel-lean zone.

In the coal tests, the new system limited NO\textsubscript{x} emissions to 25 parts per million, a level that is well below current standards for coal combustion. When used with gas-fired units, RQL technology will be able to meet even lower NO\textsubscript{x} levels.

Allison has already begun to offer RQL-equipped combustion turbines for natural gas systems in California where NO\textsubscript{x} emission limits are among the most stringent in the nation. The coal fueled version is expected to be ready for commercialization in the late 1990s.

Fuel for the tests was made from subbituminous, low-sulfur coals. In the remaining 3 years of the DOE contract, the company will focus on developing a dry, pulverized coal feed system that can replace the slurry fuel system and lower costs. Work will also include tests of advanced techniques for removing sulfur and small fly ash particles.

Allison is paying 20 percent, or $7.6 million of the project's total cost of $38.3 million. The effort is being managed by DOE's Morgantown Energy Technology Center in West Virginia.

###

COAL HYDROGEN CONTROLS CATALYST DEACTIVATION IN HRI COPROCESSING

Catalyst deactivation in coal/oil coprocessing can be controlled by selecting coals with high hydrogen content. Selected operating conditions and catalyst management concepts can further reduce catalyst deactivation.

These findings were reported in a paper by J.E. Duddy and S.V. Panvelker of Hydrocarbon Research Inc. (HRI). Their paper was presented at the American Institute of Chemical Engineers Summer National Meeting held in Pittsburgh, Pennsylvania in August.

HRI is continuing to work on the development of coal/oil coprocessing technology under the sponsorship of the United States Department of Energy and a consortium of international private industry companies.

In coal/oil coprocessing, coal is slurried with petroleum-derived residual oil. The coal is liquefied, while the petroleum-derived residual oil is simultaneously upgraded to lighter boiling products. Coal/oil coprocessing is a clean coal technology that removes both sulfur and nitrogen from the feed coal. Liquid products from coprocessing can be used directly in combined cycle combustion turbines to produce electric power with very low levels of SO\textsubscript{2} and NO\textsubscript{x} emissions.

Alternatively, coal/oil coprocessing can be used in a conventional petroleum refinery to produce high quality transportation fuels. The addition of coprocessing to a refinery increases the yield of finished products per barrel of crude oil. Coprocessing also provides the refiner with the opportunity to purchase lower priced, poor quality heavy crudes. These heavy crudes contain high proportions of residual oil, with...
high sulfur, metals and asphaltene contents, and are difficult to refine using conventional refining technologies.

Coking of these residual oils results in unacceptably high yields of poor quality (high sulfur) coke. Hydroconversion, while able to produce high yields of good quality products, uses large amounts of catalyst due to metals poisoning. In coprocessing, the presence of the coal solids provides a very effective surface for deposition of metals from these poor quality residual oils. Thus hydroconversion catalyst life is no longer limited by metals poisoning.

Figure 1 presents a simplified process flow diagram of HRJ's coal/oil coprocessing technology.

Catalyst Deactivation

In analyzing the properties of catalysts recovered from bench-scale operations, it was observed that a trend existed with respect to the average catalyst deactivation rate and carbon loading on the recovered catalyst. Figure 2 shows the average catalyst deactivation rate as a function of catalyst carbon loading. Catalyst carbon loading is expressed as the weight ratio of carbon to molybdenum on the recovered catalyst. This figure shows that the average catalyst deactivation rate is directly related to the catalyst carbon loading. This supports earlier data which has shown that carbon deposition in the initial periods of operation can contribute 80 percent of the total deactivation to equilibrium activity.

Furthermore, this initial carbon deposition can be directly attributed to coal feedstock quality. Figure 3 plots the average catalyst deactivation rate as a function of the hydrogen/carbon atomic ratio of the coal feed. Coprocessing higher hydrogen content feedstocks results in less carbon deposition and a lower catalyst deactivation rate.

In addition to feedstock effects there are other factors which can influence catalyst deactivation rates. These factors relate to the operating conditions and operating modes employed in coprocessing, specifically catalyst cascading and low/high reactor temperature staging.

In the operation of two ebullated-bed reactors in series, the recovered catalyst from the second-stage reactor can reduce or eliminate fresh catalyst addition to the first-stage reactor. The operating mode is referred to as catalyst cascading.

**FIGURE 1**

**HRI COAL/OIL COPROCESSING PROCESS FLOW DIAGRAM**
According to the paper, with catalyst cascading, fresh catalyst addition rates could be reduced by as much as 40 weight percent because the overall catalyst deactivation rate is not affected.

Another operating mode which has implications for catalyst consumption and catalyst deactivation in coal/oil coprocessing is low/high reactor temperature staging. The concept is to operate the first reactor stage at considerably lower temperature (50 to 75°F) than the second-stage. The lower temperature provides for excellent hydrogenation efficiency to improve the hydrogen donor quality of the solvent. Complete hydroconversion is then achieved in the higher temperature second-stage.

This operating mode improved selectivity to liquid products and improved product quality. It also reduced the average catalyst deactivation rate.

Summary

Catalyst deactivation in coal/oil coprocessing occurs in two parts. After a rapid initial deactivation, due to carbon deposition uniformly on the catalyst surface, a more gradual deactivation occurs, due to metals deposition, catalyst pore mouth plugging, and/or core poisoning. Coal feedstock selection can affect this initial carbon deposition and reduce the average catalyst deactivation rate by half, by selecting coals with high hydrogen content. Proper selection of operating conditions can similarly reduce the average catalyst deactivation rate by providing for improved hydrogenation conditions. Finally, catalyst cascading can further reduce fresh catalyst requirements.

###
INTERNATIONAL

IGCC BASED ON BIOMASS AND PEAT UNDER STUDY IN FINLAND

Biomass and peat are significant sources of energy in Finland, which has no oil, coal or natural gas resources. At present, fuel peat and wood wastes provide about 19 percent of Finland's primary energy, equivalent to about 5 million metric tons of oil per year. Most of this energy is used for generating heat and electricity for the process industry and for district heating in different types of boilers.

E. Kurkela and K. Sipila of the Technical Research Center of Finland (VTT) in Espoo authored a paper summarizing research activities related to power production from biomass and peat using simplified IGCC processes.

In the late 1980s an interest in integrated gasification combined cycle (IGCC) power plants was sparked in Finland. Government-funded research was directed mainly toward the utilization of indigenous fuels, wood wastes and peat. Because the potential for these fuels is mainly in medium-scale combined heat and electricity production (from 20 to 150 megawatts), research and development work was focused on simplified IGCC processes based on air gasification and hot gas cleanup.

The advantages of IGCC power production are based mainly on the potential to increase the power to heat ratio in cogeneration and on the increased efficiency of electricity production. Table 1 shows the efficiencies estimated for different simplified IGCC processes compared with those of the conventional steam process.

Finland's National Fuel Conversion Research Program plans to maximize utilization of biomass and peat in IGCC power plants. The total amount of additional electricity, as a result of the increased power to heat ratio in biomass and peat-based IGCC cogeneration, would be 2,000 megawatts by the year 2025.

Gasification Alternatives

VTT studied two alternatives for biomass gasification and hot gas cleanup. The first concept is based on fluidized-bed gasification and gas filtration by ceramic or metallic filters. The hot product gases are cooled to about 500°C before particulate removal in order to condense the vapor-phase alkali metals. Because of the low sulfur content of biomass feedstocks, no sulfur removal is needed.

The other process concept is based on fixed bed gasification and separate catalytic gas cleaning. While fixed bed gasification has a number of advantages over fluid bed gasification, gas combustion is rather problematic because of the copious production of tars and oils. In addition, if particulate removal is required and the cyclones cannot meet this task, it can be very difficult to find particulate removal equipment suitable for this tar-containing cool gas. Most of the present research activities in Finland are related to processes based on fluid bed gasification.

Pressurized Fluidized-Bed Gasification

A pressurized fluidized-bed test facility was constructed at VTT in 1986-1987 in cooperation with a Finland utility com-

### Table 1

<table>
<thead>
<tr>
<th>Separate electricity production</th>
<th>Steam Process</th>
<th>Simplified IGCC Process</th>
</tr>
</thead>
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<td>efficiency, %</td>
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<td>40 - 50</td>
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<table>
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<th>Industrial cogeneration plant</th>
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<th>Simplified IGCC Process</th>
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<tr>
<td>power to heat ratio</td>
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<td>overall efficiency, %</td>
<td>80 - 88</td>
<td>80 - 88</td>
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<table>
<thead>
<tr>
<th>District heating cogeneration plant</th>
<th>Steam Process</th>
<th>Simplified IGCC Process</th>
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</thead>
<tbody>
<tr>
<td>power to heat ratio</td>
<td>0.4 - 0.6</td>
<td>0.75 - 1.25</td>
</tr>
<tr>
<td>overall efficiency, %</td>
<td>85 - 88</td>
<td>85 - 88</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, DECEMBER 1991
pany, Imatran Voima Oy, and the Helsinki University of Technology. This test facility has been used to study the most critical aspects of the simplified IGCC concept with Finnish feedstocks. The studies have shown that the problems of biomass and peat gasification are fairly different from the key questions of coal gasification.

The most important research topics studied at this test facility in 1988 through 1991 were as follows:

- The effect of operating conditions on the formation of tars in fluid bed gasification
- Formation of nitrogen compounds from different feedstocks
- Filtration of peat and wood derived product gases at temperatures from 400 to 750°C
- The behavior of alkali metals in fluid bed gasification and gas filtration

The first wood gasification experiments led to nearly complete blocking of the ceramic filters in less than 5 hours, although the filters were operated at a rather high temperature (600 to 700°C). Heavy tars formed soot in the filter pores and also penetrated the filter. In 1991, better results were achieved by using a dolomite addition to the fluidized bed.

Because the formation of tars seems to be the most critical question of biomass-based simplified IGCC processes, the formation of tars in biomass gasification and the behavior of these tars in high-temperature filters will be studied on a more fundamental level in 1992 and 1993.

**HTW Gasifier of Kemira Oy**

The Finnish company Kemira Oy modified its oil-based ammonia plant to use peat-derived synthesis gas in ammonia production. The HTW (High Temperature Winkler) gasification plant was commissioned in 1988 and was in productional use for several thousands of hours from 1988 to 1990. In 1991, the plant was shut down for economic reasons, based on the world market price of ammonia.

Figure 1 shows a schematic diagram of Kemira Oy's peat gasification plant. Peat is dried from about 45 percent mois-
ture to 15 percent in a pressurized pneumatic steam dryer before feeding it through a lockhopper system into the gasifier. In the beginning, the heterogeneous structure of peat caused a lot of operational problems in the feedstock pretreatment equipment and in the lockhopper system. The high naphthalene content of the raw gas also caused operational problems. The problem was eliminated by raising the freeboard temperature and by adding a naphthalene removal unit to the gas purification line.

The Kemira peat gasification project proved the technical feasibility of peat-based synthesis gas production and also yielded valuable information relevant to the development of IGCC power plants.

VTT carried out tar and ammonia measurements at the Kemira gasifier in order to compare the results from a small-scale air gasifier with those from the commercial-scale steam oxygen gasifier. The tar results were surprisingly similar, showing that the effect of the gas-phase residence time and the reactor diameter are not as important as that of the feedstock properties and gasification temperature.

Commercial Activities

Tampella Corporation is commercializing the U-GAS coal gasification process, which was developed by the Institute of Gas Technology in the United States. Tampella has constructed a pilot plant at their research and development center in Tampere, Finland. Test runs will begin with coal gasification, but Tampella also plans a program of peat and biomass gasification.

A large Finnish boiler manufacturer, Ahlstrom Corporation, has developed a Pyroflow pressurized circulating fluidized-bed combustion process for coal. Ahlstrom is cooperating with a Swedish utility company, Sydkraft, in order to demonstrate a simplified IGCC process for biofuels. A small demonstration plant with a capacity of 6 megawatts electricity and 10 megawatts district heat will be constructed in the town of Varnamo, Sweden.

The Finnish utility company, Imatran Voima Oy (IVO), is developing an advanced gas turbine power plant process for wet fuels like peat, biomass and lignite. The process consists of a steam-injected gas turbine, an air-blown gasifier and a pressurized fuel dryer. The process is patented and called IVOSDIG (Imatran Voima's steam drying, injection gasification) process. IVO's development work aims at reaching a commercial level for the peat based process towards the end of the 1990s.

China Plans More Coal Gasification Plants

With approximately 70 percent of China's energy coming from coal, advanced coal utilization technologies are needed to improve the country's level of energy efficiency and to reduce air pollution. According to a report from China Daily, a Canadian firm has agreed to design and equip a coal gasification plant in Kunming, Yunnan Province. The contract is the first in a series of expected contracts to provide coal gasification plants in a number of Chinese provinces.

Joe Ng Engineering, based in Ontario, Canada, has contracted to design and equip the plant in Kunming with the support of a $5 million loan from the Canadian Export Development Corporation to the Bank of China.

The coal gasification plant will convert low grade coal to coal gas, which can be burned to produce cleaner power. The Kunming plant is scheduled to be completed in 2 years and will produce about 220,000 cubic meters of gas per day.

According to Joe Ng, president of the company, "Air pollution knows no geographic boundaries. And for air quality to improve, China needs both modern technology and large-scale foreign government financing to invest in these environmental public works projects. Building coal gasification plants in China will produce better living for the whole world."

Ng's company is also considering coal gasification projects in both Xinxiang and Luohe in Henan Province.

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Sasol to Expand Chemicals Production

Sasol has authorized final engineering for a $90 million alpha olefin purification facility to be located at Secunda, South Africa. According to European Chemical News (ECN), Sasol will target the markets for pentene, hexene and other higher olefins.

Startup of commercial operations is planned for late 1993 with over 750,000 tonnes of product produced per year. Products from the facility will range from C_5 through C_8 alpha olefins that are contained in the product streams from the two coal-based synthesis gas plants at Secunda. The company is also considering marketing quantities of alpha olefins higher than C_8.

The purification of these streams will recover nearly 170,000 tonnes per year of copolymer grade 1-hexene, which will be marketed first. According to ECN, the company will target growing demand in markets in Africa, Asia and the Middle East.
Polymerization pilot plants have been testing the new 1-hexene comonomer and preliminary results have shown no signs of catalyst poisoning. The pilot plants will supply product for commercial testing while the commercial-scale plant is being designed and constructed.

ECN reports that SASOL has also approved the design of the purification facility that will allow the processing of streams containing comonomer grade 1-pentene, which would result in 250,000 tonnes of the product per year.

The company is also planning new product development of pentene copolymers, saying that 1-pentene copolymers could potentially improve 1-butene copolymers for ultralow density polyethylenes and elastomeric polyethylenes. In addition, 1-pentene copolymers are expected to replace 1-butene copolymers to meet food grade restrictions.

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200 TPD IGCC PILOT IN OPERATION IN JAPAN

Japan's New Energy and Industrial Technology Development Organization (NEDO) is studying integrated gasification combined cycle (IGCC) technology as part of a national energy project called the "Sunshine Project." NEDO is currently operating a 200 ton per day IGCC pilot plant at the site of the Naksoso Power Station in Iwaki City, Fukushima Prefecture.

NEDO's T. Shimada reported on IGCC development in Japan at the American Institute of Chemical Engineers Summer National Meeting held in Pittsburgh, Pennsylvania in August.

**Research and Development**

In 1973, an IGCC project employing a fluidized bed gasifier was developed. The Coal Mining Research Center Japan (CMRCJ), under the direction of the Ministry of International Trade and Industry (MITI), installed a 40 ton per day pilot plant at Yuubari, Hokkaido. The Yuubari plant consists of a two-stage fluidized bed gasifier, a two-stage fluidized bed desulfurizer using iron-oxide as sorbent, a granular filter using silica sand or mullite for filtration, and a gas turbine test facility with a combustor. This plant was operated from 1981 to 1987.

Meanwhile, in 1981 NEDO conducted a feasibility study for a 1,000 megawatt IGCC fluidized bed gasification power station. In 1985, research and development of IGCC technology with an entrained flow gasifier was included in the Sunshine Project. The 200 ton per day pilot plant was constructed at the Naksoso Station and operations began in March 1991.

**IGCC Pilot Plant**

The Japanese Government decided to develop IGCC technology with an entrained flow gasifier because of its higher efficiency and better environmental acceptability. 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, environmental performance similar to oil-fired plants, 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 IGCC technology with a fluidized bed gasification pilot plant. NEDO has contracted with 10 electric utility companies and 1 laboratory to assist in the development of this technology.

The gasifier is an air-blown, two-stage entrained flow type with a dry feeding system. The gas cleanup system consists of a two-stage fluidized bed desulfurizer and a granular bed filter, using iron-oxide particles as sorbent and synthetic filtrates as granular bed.

A heat recovery steam generator and a steam turbine were not installed. Therefore, the performance of the total combined cycle system will be confirmed and evaluated by simulation.

The pilot plant started in distillate dry-up operation in March 1991. Coal gasification began in June. NEDO expects to operate the pilot for 3 years using four different kinds of coal. The Yuubari plant was operated as a support study of the gas cleanup system from 1988 to 1990.

A diagram of the pilot plant, shown in Figure 1, was provided by Y. Wajiki of the Engineering Research Association for Integrated Coal Gasification Combined Cycle Power Systems, the company that designed and constructed the facility.

The plant is designed to produce 42,900 cubic meters of synthetic gas per hour with a carbon conversion efficiency of 97 percent or higher.

The pilot plant will be tested using three different types of coal, classified according to their difficulty in gasifying. Initially, the plant will gasify an "easy-to-gasify" coal having a low fusion temperature and low fuel ratio. This will provide an opportunity to make any needed adjustments to the equipment.

Following that, coal with a medium ash fusion temperature and medium fuel ratio will be used to determine the performance of each piece of equipment and to perform improvement tests on various components. Finally, a coal that is "difficult to gasify" will be used to conduct tests aimed at improving the scope of applicable coal types.
CIAB SEES OPPORTUNITY TO REDUCE CARBON DIOXIDE EMISSIONS FROM COAL

A technical report from the Coal Industry Advisory Board (CIAB) says there are substantial opportunities to reduce emissions of carbon dioxide (CO₂) through improved efficiency of coal utilization and by applying state-of-the-art technology, particularly in developing countries.

The CIAB report, titled "Potential to Reduce Carbon Dioxide Emissions," also contains a policy statement from the board on global climate change.

According to the report, virtually every assessment of future energy requirements indicates that the world will remain heavily dependent on coal as a secure and low cost supply of energy. There is however, growing concern about the contribution of coal combustion to global carbon dioxide emissions and the potential impact this may have on future global climate patterns.

Currently, the most practical and economical method for reducing CO₂ emissions from coal is to increase the energy efficiency of coal utilization technologies. This is particularly true for power generation, where each 1 percentage point increase in absolute power generating efficiency results in a 3 to 4 percent reduction in CO₂ emissions, says CIAB.

Existing advanced technologies for producing power from coal can achieve significant reductions in CO₂ emissions compared with the average thermal power plant currently in operation. In addition, there are a number of developing coal utilization technologies that offer the potential for even greater levels of energy efficiency.

Table 1 provides a comparison of the power generation efficiencies of commercially advanced, imminent and developing coal utilization technologies against two base levels of thermal power plant efficiency. The higher figure represents the current level of thermal power plant efficiency in developed countries, while the lower figure represents the level of efficiency in less developed countries. Also shown is the potential for reducing CO₂ emissions as low-efficiency thermal power plants are replaced by commercially advanced, imminent and developing coal utilization technologies.

As indicated in Table 1, present coal utilization technologies such as advanced pulverized coal (PC) boilers and atmospheric fluid bed combustion (AFBC) can achieve reductions in CO₂ emissions of 9 to 31 percent as compared with existing thermal power plants. Pressurized fluidized bed combustion (PFBC) and integrated gasification combined cycle (IGCC) are technologies that are expected to be in widespread commercial use by the end of this decade. These tech-

### Table 1

**Comparison of Various Coal-Fired Power Generation Technologies**

<table>
<thead>
<tr>
<th>Technology</th>
<th>Potential Reduction in CO₂ Emission From Base (%)</th>
<th>Energy Efficiency From Low</th>
<th>From High</th>
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<tbody>
<tr>
<td>Base Case</td>
<td></td>
<td></td>
<td>Base</td>
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<tr>
<td>Existing Thermal Power Plants</td>
<td>25 - 33</td>
<td></td>
<td>Base</td>
</tr>
<tr>
<td>Commerically Advanced</td>
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<td></td>
<td>Base</td>
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<tr>
<td>Pulverized Coal (PC)</td>
<td></td>
<td>37</td>
<td>31</td>
</tr>
<tr>
<td>Atmospheric Fluidized Bed Combustion (AFBC)</td>
<td></td>
<td>37</td>
<td>31</td>
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<tr>
<td>Imminent</td>
<td></td>
<td></td>
<td>Base</td>
</tr>
<tr>
<td>Pressurized Fluidized Bed Combustion (PFBC)</td>
<td></td>
<td>40</td>
<td>36</td>
</tr>
<tr>
<td>Integrated Gasification Combined Cycle (IGCC)</td>
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<td>39</td>
</tr>
<tr>
<td>Hybrid (IGCC/FBC)</td>
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<td>Developing</td>
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<td>IGCC/Fuel Cells</td>
<td></td>
<td>50</td>
<td>49</td>
</tr>
<tr>
<td>Magnetohydrodynamics (MHD)</td>
<td></td>
<td>55</td>
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</tr>
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</table>
nologies offer the potential for reducing CO₂ emissions from 16 to 45 percent versus existing coal-fired power plants. In the long term, IGCC/fuel cells and magnetohydrodynamics (MHD) offer the potential for reducing CO₂ emissions by more than 50 percent compared to existing coal-fired power plants.

Figure 1 depicts the level of CO₂ reduction that can be achieved through improved efficiency of coal utilization and through application of advanced emerging technologies.

Those technologies that have the greatest near-term potential for reducing CO₂ emissions from thermal power plants include commercially advanced PC boilers, fluidized bed combustion (both atmospheric and pressurized) and IGCC. Following is a summary of the state of development of each of these technologies.

Pulverized Coal

Commercially advanced PC boilers equipped with flue gas desulfurization (FGD) systems for SO₂ control have been operated with efficiencies of 37 percent. These power generation systems were built in the last 10 to 15 years and were designed to meet strict environmental standards and with improved efficiencies to meet the higher cost of fossil fuels. The commercially advanced SO₂ FGD systems (wet lime or limestone) also have been designed to minimize power consumption, maintaining overall power plant efficiencies in the range of 36 to 38 percent.

According to the report, longer term, ultra-supercritical steam conditions in pulverized coal-fired power plants offer the potential for energy efficiencies approaching 45 percent. Improvements would involve higher combustion temperatures and pressures, which would require the introduction of new materials and production technologies (e.g., welding and machining processes). Progress already has been made in developing suitable materials having appropriate mechanical characteristics and showing resistance to hot corrosion and steam oxidation.

Fluidized Bed Combustion

AFBC has the potential for reliable and economic burning of a wide range of coal types with plant efficiencies approaching 37 percent.

Fluidized bed combustion technologies also reduce emissions of sulfur and nitrogen oxides. Sulfur oxides can be captured by the use of limestone in the combusting bed, while nitrogen oxides are reduced by avoiding high temperature combustion. FBC plants are already commercially available up to a scale of 150 megawatts. The technology is suitable for repowering existing power plants and reducing carbon dioxide emissions by up to 30 percent.

The advantages of AFBC will be extended by the development of PFBC, which is expected to achieve efficiencies of over 40 percent. Several PFBC units are operating, under construction, or planned for the United States, Europe, and Japan. The 70 megawatt Tidd project in the United States is sponsored by the United States Department of Energy (DOE) Clean Coal Technology Program. The 330 megawatt Sporn repowering project is planned to go into operation in 1996 and is also sponsored by DOE. Two cogeneration units were started up in Sweden in 1990 and will produce 135 megawatts. An 80 megawatt Spanish unit was commissioned in late 1990 with plans for a second 350 megawatt installation.

Energy efficiencies approaching 45 percent may be achievable in the future with the application of ultra-supercritical steam conditions to FBC technology. A 70 megawatt PFBC combined cycle demonstration plant incorporating an ultra-supercritical steam turbine will be operational in Japan by 1994 leading to a commercial plant in 1997.

Integrated Gasification Combined Cycle Technology

Integrated gasification combined cycle technology has been identified by a growing number of utilities as the dominant coal-based power generation technology for the future.

IGCC, using any type of coal, can achieve efficiencies of 42 percent with a corresponding reduction in CO₂ emissions. In the oxygen-blown version, the gasifier product is cooled to remove 99 percent of the sulfur as a byproduct. This system is commercially available worldwide. The air-blown IGCC version with hot gas cleanup offers the potential for even higher energy efficiencies, but this technology is not yet developed beyond the large pilot plant stage. Several large-scale air-blown IGCC demonstration projects are planned in the United States and Europe.
A hybrid, or topping cycle, also is being developed. In this system the coal is partially gasified and then combusted to provide high turbine inlet temperatures. Coal which is not gasified is fed as a char to an FBC unit. The FBC unit provides flue gas for the gas turbine and steam for the steam turbine. As shown in Table 1, the hybrid cycle has the potential for achieving a 46 percent energy efficiency with a corresponding reduction in CO\(_2\) emissions. Air-blown IGCC hybrid cycles are being piloted and demonstrated in the United States and the United Kingdom and could be ready for commercial deployment in the late 1990s.

According to CIAB, promising developments in Japan and other countries with high inlet temperature, high-efficiency gas turbines could make IGCC even more attractive in the future. Another concept, called externally fired combined cycle (EFCC), employs a ceramic heat exchanger being developed specifically for gas turbines. EFCC is still in the small pilot plant stage, but could offer the potential for coal utilization efficiencies approaching 43 percent for small blocks of about 50 megawatts.

Developing Technologies

Two developing technologies for power generation are fuel cells and magnetohydrodynamics. While commercial development of these technologies will probably not occur until after the year 2000, they illustrate the future potential for excellent energy efficiency and CO\(_2\) emission reduction.

Fuel cells are devices in which hydrogen obtained by reforming natural gas, methanol, or coal gas reacts electrochemically with oxygen from the air to generate electric power. Fuel cells have the potential for a power generation efficiency of 50 percent and corresponding low CO\(_2\) emissions. When exhaust heat from fuel cells is utilized in cogeneration systems, even higher efficiencies could be realized. Low environmental emissions plus the absence of mechanical moving parts that generate vibration or noise make fuel cells very favorable in terms of environmental impact and siting issues.

The energy efficiency of the MHD system is expected to approach 55 percent. In a coal-fired MHD system, coal is burned to produce an extremely hot gas or plasma. A chemical "seed" (for example, a potassium compound) is added to give the gas an electrical charge. The charged gas is passed through a strong magnetic field producing electricity. Heat from the combustion gases is used to generate additional electricity by means of a conventional steam turbine. Research on MHD systems is being conducted in several countries, including Japan and the United States.

Carbon Dioxide Removal and Storage

Several processes have been considered for the removal of carbon dioxide from combustion gas and its storage. The technologies for CO\(_2\) removal are available, but would add substantial cost to power generation, says the report. Water, methyl ethano-lamine, lime, caustic soda, and physical solvents have been suggested as agents for removing carbon dioxide. Liquefaction is a possibility, particularly if an oxygen-carbon dioxide combustion gas mixture or oxygen-gasification is used. Proposed storage methods for carbon dioxide include dissolution in deep oceans and saline aquifers, storage as liquid carbon dioxide in depleted gas and oil reservoirs, in caverns, or as plant material.

The International Energy Agency is evaluating all of these possibilities and promoting a cooperative program to analyze options for CO\(_2\) removal, utilization and disposal from coal fired stations. The goal is to determine the technical feasibility and the costs involved in such approaches and to demonstrate that they are environmentally acceptable. Based on current technology, however, CO\(_2\) removal and storage is not a realistic option because of its extremely high cost and the uncertainty of containing stored material indefinitely.

Policy Statement on Global Warming

In a separate policy statement, the CIAB called government policies to control greenhouse gases "imprudent" if they do not consider fully the economic and social impacts on society.

"Nowhere is this more true than in the energy sector," said B.R. Brown, CIAB member and chairman of the global climate committee of the CIAB. "Energy policy decisions can have a pervasive and profound impact on economic development and the efficient use of energy resources throughout the world. We are concerned that governments in several industrialized countries have enacted target limits on greenhouse gases without sufficient consideration of the long-term social and economic consequences; without adequate information on the effectiveness of such actions in reducing global greenhouse gases; or without specific plans for how the targets are to be achieved."

The CIAB encouraged industry and government groups to pursue joint programs to commercialize technologies which improve fossil fuel combustion efficiencies. The statement also urged governments to reduce institutional barriers to investment in commercially unproven power generation technologies and to review regulatory and taxation policies that may influence choices between fuels. "The CIAB is particularly concerned that the crucial contribution of coal to energy needs should not be jeopardized by fiscal or regulatory measures which place it at a relative disadvantage."

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BLM AFFIRMS MONTANA LEASES WITH CULTURAL STIPULATIONS

Four federal coal leases in Montana have been affirmed in a Record of Decision from the Montana State Office of the Bureau of Land Management (BLM), United States Department of the Interior. In compliance with a decision handed down by the District Court of Montana, the Colstrip leases (M54711, M54712, and M54713) and the West Decker lease (M54716) have been affirmed, subject to certain cultural stipulations.

Although the Economic, Social and Cultural Supplement to the Powder River I Regional Environmental Impact Statement found that there were no social or economic impacts associated with these leases, it does indicate that the leasing and development of these tracts would have cultural impacts. The cultural impacts would occur to the belief and value systems of the Northern Cheyenne and Crow Tribes.

Cultural Impacts

Belief and value systems are spiritual and are often associated with a range of geographic and anthropologic sites found on the tracts and adjacent terrain—tangible objects and physical features. They are also associated with a range of intangible values, such as spirits associated with wells and springs and the isolation and privacy necessary for meditation or certain religious ceremonies.

Both tribes contend that the spiritual and physical values of their belief systems can only be sustained by totally avoiding any mining and associated support activities on the subject tracts. Further, it is their belief that these spiritual values will be unalterably destroyed and that there are no measures by which to mitigate the impacts of mining.

However, BLM says that years of experience in administering mining operations on federal mineral leases have indicated that, while surface mining and subsequent reclamation may be temporarily disruptive to the belief and value systems of Native Americans, the impact on tangible physical objects and features can often be effectively reduced or eliminated by intense on-site surveys coupled with the development of appropriate requirements to inventory, excavate, and/or restore such sites and features, when appropriate. Intangible factors may also be able to be mitigated, depending upon what is discovered during the inventory.

Mitigation

Because the potential cultural impacts are similar for both the Northern Cheyenne and the Crow Tribes and because they are common to all four coal leases, only one mitigation measure is being imposed. This measure revises the cultural resources stipulation in the current leases to accomplish the following:

- Recognize the intangible as well as tangible cultural resources
- Involve the Northern Cheyenne and the Crow Tribes in the cultural resource inventory more intensively than previously
- Accommodate changes in statutes, organizational structures, and cultural resource management policy occurring since 1982

The revised stipulation states that before undertaking any activities that may disturb the surface of the leased lands, the lessee shall conduct a cultural resource intensive field inventory. Cultural resources are defined as a broad, general term meaning any cultural property or any traditional lifeway value.

The stipulation goes on to define "cultural property" and "traditional lifeway value" in detail. These are essentially the tangible and intangible cultural assets associated with the property by the Northern Cheyenne and Crow Tribes.

Prior to beginning the prescribed cultural resource field inventory, the lessee must first consult with the BLM, the Northern Cheyenne Cultural Protection Board, and the Crow Historic and Cultural Committee. The purpose of the consultation is to guide the work to be performed and to identify any cultural properties or traditional lifeway values within the area.

Further, the lessee is not allowed to commence with surface disturbing activities until permission to proceed is given by the regional director in consultation with the authorized officer.

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The following papers were presented at the American Chemical Society meeting held in New York City, New York, August 25-30:


Choudhry, V., et al., "Utilization of Coal Gasification Slag: An Overview"

Najjar, M.S., et al., "Phase Characterization of Unmodified Petroleum Coke and Coal Gasification Slags"

Fu, Y.C., et al., "Coal/Oil Coprocessing Using Syngas"

Song, C., et al., "Catalysis of Metal-Ion Exchanged Y-Zeolites and Modified Ni-Mo/Al₂O₃ for Hydrocracking of Phenanthrene and Coal-Derived Distillates"

Hager, G.T., et al., "Ultrafine Iron Carbide as Liquefaction Catalyst Precursor"

Xu, L., et al., "Catalytic Hydrotreatment of Coal-Derived Naphtha"

Lee, J.M., et al., "Distillate Selectivity and Quality of Bituminous Coals in the Catalytic Two-Stage Liquefaction Process"

Skodras, G., et al., "Two Stage Gasification: Effect of Hydropyrolysis Conditions"

Vorres, K.S., et al., "Moisture Removal from and Liquefaction of Beulah-Zap Lignite"

Owens, R.M., et al., "Hydrogen Transfer from Naphthenes to Coal During Coprocessing"

Timpe, R.C., et al., "Catalytic Effect on the Gasification of a Bituminous Argonne Premium Coal Sample Using Wood Ash or Taconite as Additive"

Kapteijn, F., et al., "A Transient Kinetic Study of the Gasification of Carbon in CO₂"

Cacho, J.M., et al., "The Role of Activated Diffusion in the Gasification of Porous Carbons/Chars"

Calemma, V., et al., "Influence of Maceral Composition of Raw Coal on Potassium Activity in Steam Gasification of Chars"

Leon y Leon, C.A., et al., "Effect of Thermal and Chemical Pretreatments on the Copper-Catalyzed Gasification of Carbon in Air"

Cazorla-Amoros, D., et al., "Further Evidence on the Mechanism of the CO₂ Carbon Gasification Catalyzed by Calcium: TPD After ¹³C₂ Chemisorption"

Bartholomew, C.H., et al., "Catalysis of Char Gasification in O₂ by CaO and CaCO₃"

Kapteijn, F., et al., "Potassium-Catalyzed Carbon Gasification in CO₂ Studies by Transient Techniques"

Rodriguez, J., et al., "In Situ Evaluation of the Carbonization Behavior of Graphitizable Carbon Precursors"

Walker, D.G., "Coal and Carbon in the Post-Petroleum World"

Arnett, E.M., et al., "Acid-Base Properties of Coals and Coal Liquids"

Brandes, S.D., et al., "The Application of Advanced Analytical Techniques to Direct Coal Liquefaction"

Kamo, T., et al., "Hydrogen Transfer During Coal Liquefaction Determined by $^2$H/$^1$H Measurement"


Sharma, D.K., et al., "Mechanism of Successive Solvolytic Extraction of Coal"

The following presentations were made at the EPRI 10th Annual Conference on Gasification Power Plants held in San Francisco, California, October 16-18:


Adlhoch, W., et al., "The Rheinbraun HTW Coal Gasification Process—The Clean Way from Coal to Electricity"

Koleda, M. "GCC Benefits—A Statement from the Council on Alternate Fuels"

Brady, J.M., "The Similarity of Texaco's Gasification Process for Utility and Industrial Applications"

Sundstrom, D., et al., "The Destec/PSI Energy 265 MW Repowering Project"

Van Laar, J., et al., "Comparison of GCC Integration Concepts"

Bechtel, T., "Gasification—A Key for Advanced Power Systems"

Furfari, S., "Gasification and IGCC Within the European Communities"

Mahagaokar, U., et al., "Shell's SCGP-1 Test Program—Final Overall Results"

Lacey, J., et al., "An Update on the BGL Gasifier"

Schellburg, W., "Status of PRENFLO Technology"

Kern, E., "Coproduction of Fuels, Chemicals, and Power"

Bradshaw, D., et al., "TVA's Coproduction of Electricity and Fertilizer Project"

Becker, B., "Low Emission Coal-Derived Gas Combustion in Advanced Gas Turbines"

Allen, R., "Further Progress in the Application of Advanced Gas Turbines to IGCC"

Day, W., et al., "FT400 HAT: A 250 MW Class Aeroderivative Gas Turbine"

Cohn, A., et al., "The Application of Humidification to Integrated Coal Gasification/Compressed Air Storage Power Plants"

Drnevich, R.F., et al., "Air Separation Integration for GCC Plants"

Sorensen, J., et al., "Cost Effective Oxygen for GCC—Matching the Design to the Project"

Corman, J.C., et al., "Hot Gas Cleanup Developments"

Gogineni, M.R., "CE Air-Blown Gasification Process for Power"

Mojtahedi, W., et al., "Development of Tampella IGCC Process"

Wajiki, Y., "Current Status of R&D for 200 T/D Entrained Flow Coal Gasification Power Generation Pilot Plant"
Hojlund Nielsen, P.E., et al., "The Topsoe Steam Regenerable Sulfur Absorption Masses and Their Application in IGCC Plants"

Cahill, P. et al., "Hot Gas Clean Up for the British Coal Topping Cycle"

Niemeyer, V., "Status of Externalities Considerations in the U.S., Potential Implications for Technology Selection"

Gillis, E., "Fuel Cells—Key Technology for Minimization of Externalities"

Van der Burgt, M., et al., "CO₂ Disposal from Coal Based IGCC's in Depleted Gas Fields"

The following articles appeared in Energy & Fuels, September/October 1991:

Davis, B.H., et al., "Liquefaction Pathways of U.S. Bituminous Coals"

Satou, M., et al., "Determination of Atomic Groups of Hydrocarbons in Coal-Derived Liquids by High Performance Liquid Chromatography and Nuclear Magnetic Resonance"


Niksa, S., et al., "FLASHCHAIN Theory for Rapid Coal Devolatilization Kinetics. 1. Formulation"

Niksa, S., "FLASHCHAIN Theory for Rapid Coal Devolatilization Kinetics. 2. Impact of Operating Conditions"

Niksa, S., "FLASHCHAIN Theory for Rapid Coal Devolatilization Kinetics. 3. Modeling the Behavior of Various Coals"

Tomita, A., et al., "Study of Ca Catalysis on Carbon Gasification with 18O₂"


Joseph, J.T., et al., "Coal Maceral Chemistry. 1. Liquefaction Behavior"

COAL - PATENTS

"Slurry Hydrotreating Process," Willard H. Sawyer, William E. Winter, Jr. - Inventors, Exxon Research and Engineering Company, United States Patent Number 5,037,532, August 6, 1991. A slurry hydrotreating process is described in which a hydrotreating catalyst of small particle size is contacted with a heavy fossil fuel. High catalyst activity is maintained by circulating the catalyst between a hydrotreating zone and a reactivating zone where the catalyst is hydrogen stripped.

"Method and Apparatus for Desulfurizing and Denitrifying Coal," Timothy C. Keener, Soon-Jai Khang - Inventors, University of Cincinnati Research Foundation, United States Patent Number 5,037,450, August 6, 1991. An apparatus and process for desulfurizing and denitrifying coal by pyrolysis and subsequently treating the gaseous pyrolysis byproducts with a solid sorbent to substantially reduce the release of SO₂ gases to acceptable levels. In one aspect of the invention, coal in pyrolyzed in the inner chamber of the desulfurization and denitrification apparatus to drive off the sulfur and nitrogen compounds contained therein. In another aspect of the invention, the gaseous byproducts of pyrolysis are treated with a solid sorbent in the outer chamber of the desulfurization and denitrification apparatus to substantially desulfurize those gases. In a further aspect of the invention, the desulfurized gases, which contain nitrogen compounds, are combusted under controlled conditions to minimize the production of NOX gases.

"Method for Beneficiation of Low-Rank Coal," Linda Atherton - Inventor, Electric Power Research Institute, United States Patent Number 5,035,721, July 30, 1991. A method is provided for removing moisture and improving the handling and storage characteristics of low-rank coal by demoisturizing the coal and rendering the coal surfaces hydrophobic, separating the fines and agglomerating the fines in a slurry.

"Apparatus for Thermal Pyrolysis of Crushed Coal," Reginald D. Richardson - Inventor, United States Patent Number 5,034,021, July 23, 1991. Apparatus is described for the pyrolysis of coal comprising a pyrolysis tower through which crushed coal and hot gas are counter-currently passed. The tower enables a controlled temperature profile to be maintained in the tower, and contains inner appurtenances which define cascading passageways to promote heat exchange and mixing of the coal with the hot gas. The coal
volatiles are carried out of the top of the tower by the gas. The pyrolysis tower may be conjoined with a gasifier so as to most directly utilize the char residuals remaining after pyrolysis of the coal while they are still hot to more efficiently produce a hot synthesis gas, to be used to perform thermal pyrolysis in the tower.

"Method for Passivating Particulate Coal," Gerhard J.A. Kennepohl and Frank Souhrada - Inventors, Alberta Research Council, United States Patent Number 5,033,230, July 23, 1991. A method is disclosed for drying and passivating wet coals, for example bituminous, subbituminous or lignite. The wet coal is introduced into a heating zone at a controlled rate, then is contacted with a heavy hydrocarbonaceous treatment material having a softening point of at least 60°C. The particles and treatment material are simultaneously intimately mixed and are heated to a temperature of at least 200°C but below the coal decomposition temperature while being moved along the heating zone in a plug flow manner. The particles are then cooled in a cooling zone.

"Process for Beneficiation of Coal and Associated Apparatus," Amol A. Kulkarni - Inventor, Viking Systems International Inc., United States Patent Number 5,032,257, July 16, 1991. A process for removing mineral matter from coal is disclosed. The process involves creating ultra-fine coal by pulverizing the coal feed material and mixing it with an aqueous amine solution. The coal/amine solution is fed into a flotation cell and gaseous carbon dioxide is charged into the cell. The carbon dioxide reacts with the amine solution to form bubbles which carry the "clean" coal component of the coal feed material to the top of the cell for subsequent removal from the cell. The bubbles are reduced in size as they move up within the cell. The mineral matter, which is heavier than the clean coal, stays at the bottom of the cell and can be removed separately. The amine and the carbon dioxide used in the process can be recycled. An associated apparatus is also disclosed.

"Coal Extraction," Gordon Dennison, Geoffrey M. Kimber, Terry D. Rante - Inventors, Coal Industry Ltd GB, United States Patent Number 4,997,548, March 5, 1991. Recycled oil solvents for coal extraction have their content of saturated cyclic species reduced by thermal cracking at 470 to 540°C for a few minutes, restoring their effectiveness as solvents for coal.
STATUS OF COAL PROJECTS

COMMERCIAL AND R&D PROJECTS (Underline denotes changes since September 1991)

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 a new nuclear power generating plant.

APAC has 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 modest capacity of the plant and 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 APAC coal gasification process can emphasize either acetylene production 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 MAP. 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.

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The improved deashing configuration also resulted in additional product recovery attributable to recycling ashy bottoms. For bituminous coal, conversion of the incremental product was achieved by adding another catalyst (cobalt-based Amocat 1-A) to the first stage reactor, resulting in a 70 percent MAP distillate yield. For subbituminous coal, more thermal volume was used, resulting in a 61 percent MAP distillate yield. Use of the first stage catalyst also reduced the deactivation of the more active second stage catalyst.

Later results showed that nickel-based bimodal catalysts can be used in both reactions, thereby allowing the aged catalyst from one stage to be cascaded to the other. This can increase operating flexibility and reduce overall catalyst cost.

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.

Current work using 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. Additional efforts regarding reactor optimization are 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, (C-465)

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 (10 tonne/hr) which will be built at British Coal’s Grimethorpe site in South Yorkshire.

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 driving off calcium sulfate and other volatiles, and to avoid sintering of the ash. This comparatively low temperature 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, raising the 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 10 tonne per hour gasifier.

The gas turbine operation is funded by British Coal, United Kingdom Department of Energy, PowerGen, 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.

A fluidized bed combustion system has been commissioned at the plant to overcome problems of ash disposal. The proposed system generates additional steam, and has reduced requirements for land for ash disposal.

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.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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 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 char 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, is being carried out by a working group made up of BEWAG/EAB (Berlin), Ruhrkohle Oel und Gas GmbH (Bottrop), and Lurgi GmbH (Frankfurt), under the project leadership of EAB Energie-Anlagen Berlin GmbH.

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 feasibility study was made on the basis of detailed technical planning. The main result of the study is the minimized 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 capacity 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°C.
COMMERCIAL AND R&D PROJECTS (Continued)

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.

In 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

BHEL COMBINED CYCLE DEMONSTRATION PLANT – Bharat Heavy Electricals Limited (India) (C-50)

Bharat Heavy Electricals 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

BOTROP 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 the Federal Republic of Germany (C-60)

During operation of the pilot plant the process improvements and equipment components have been tested. The last improvement made being 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 raffinate 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)

BRICC COAL LIQUEFACTION PROGRAM – Beijing Research Institute of Coal Chemistry - BRICC (C-68)

In the early 1980s, China renewed study on direct liquefaction with emphasis on converting coal into clean liquid fuel by direct hydrogenation. Two continuous process units (CPU) were set up at the Beijing Research Institute of Coal Chemistry. The 0.1 ton per day continuous liquefaction unit, set up jointly by China and NEDO (New Energy Development Organization) of Japan, had
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

been operating for more than 1,000 hours as of 1990. A five kilogram per hour CFU using "New German Technology" was introduced from the Federal Republic of Germany. To study various coal liquefaction processes and operation conditions, a 1.8 kilogram per hour slurry continuous liquefaction unit from Xytel Company of the United States was also installed.

A 24 tons per day coal throughput gasifier was to be put in operation in late 1990. A demonstration plant will then follow in the next five years.

At present, research is being carried out in the following areas: (1) evaluation of coal liquefaction characteristics; (2) suitability of coal for small-scale continuous liquefaction units; (3) selection and evaluation of catalysts, and (4) upgrading of coal liquefaction products. Tests have shown that some Chinese lignite and high-sulfur coal are ideal feedstocks for liquefaction. The high sulfur bituminous coal from Tengxian and Beizu of Shandong province have very good liquefaction behavior and the oil yield can reach 50 percent. The liquefaction behavior of lignite from Inner Mongolia and Yunnan is also good. A NiMo catalyst, natural iron ore powder, ferrous disulfide, red mud from several aluminum factories and some compounds containing iron have been tested successfully.

Research on indirect liquefaction, i.e., modification of the Fischer-Tropsch synthesis process is also being carried out by the Shanxi Research Institute of Coal Chemistry of the China Academy of Science. Based on laboratory study and tests in a single tube of 50 millimeter diameter, a pilot test with an output of 100 kilograms per day of synthetic oil underwent tests in a chemical fertilizer plant in 1990.

BRITISH COAL LIQUID SOLVENT EXTRACTION PROJECT — British Coal, British Department of Energy, European Economic Community, Ruhrkohle AG, Amoco (C-70)

British Coal has built 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 undissolved 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 ebullating bed hydrocracking reactors.

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 H$_2$ 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 I 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
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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 10 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.

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 but Calderon plans to reapply under Round 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

SYNTHETIC FUELS REPORT, DECEMBER 1991
COMMERCIAL AND R&D PROJECTS (Continued)

CAN DO PROJECT – Continental Energy Associates (C-100)

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 100 megawatt 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. The electricity 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.

The new facility is owned by Continental Energy Associates.

Project Cost: over $100 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 Charfucl 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.

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

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.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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 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 – Fundacáo 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. The result of this stage, a conceptual design for a prototype plant will be made. This prototype plant will be operational in 1992 and in 1994 the basic project for the demonstration unit will be started. The demonstration unit is planned to be operational in 1998.

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 – Fundacáo de Ciencia e Technologia - 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 Candiota 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.

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.

SYNTHETIC FUELS REPORT, DECEMBER 1991
A 120 MW(e) coal-gas based combustion turbine combined cycle power generating system is planned for Tallahassee, Florida. The plant will include an air blown coal 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, as proposed, will be built on a site outside Tallahassee, Florida near the existing Arvah B. Hopkins Power Station. The power plant will burn 1,270 tons per day of IS to 33 percent sulfur eastern coal. In addition, the project will provide steam to a commercial facility to be built adjacent to the property.

The air blown integrated gasification combined cycle (IGCC) project is being developed by Clean Power Cogeneration Inc., a 50/50 joint venture between CRSS Capital, Inc., a leading independent power producer, and TECO Power Services (TPS), a subsidiary of a major southeastern electric utility. CRSS/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 16CC 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 120 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.

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-150)

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-160)

The Colombian state coal company, Carbocol plans for a coal gasification plant in the town of Amaga in the mountainous island department of Antioquia.
COMMERCIAL AND R&D PROJECTS (Continued)

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 Carbocol 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

COOL WATER COAL/MSW GASIFICATION PROGRAM – Texaco Syngas Inc. (C-170)

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. The California Energy Commission approved the state environmental permit in December 1979 and construction began in December 1981. Plant construction which took only 2.5 years, was completed on April 30, 1984, a month ahead of schedule and well under the projected $300 million budget. A five-year demonstration period was completed in January 1989.

Texaco and Southern California Edison (SCE), which have contributed equity capital of $45 million and $25 million respectively to the effort, signed the joint participation agreement on July 31, 1987. The Electric Power Research Institute (EPRI) executed an agreement to participate in the Project in February 1980 and their contribution was $69 million. Bechtel Power Corporation was selected as the prime engineering and construction contractor and also executed a participation agreement in September 1980 and have contributed $30 million to the project. General Electric signed a participation agreement in September 1980. In addition to contributing $30 million to the Project, GE supplied the combined cycle equipment. The JCWP Partnership, comprised of the Tokyo Electric Power Company, Central Research Institute of the Electric Power Industry, Toshiba CGP Corporation and HHI Coal Gasification Project Corp. signed a participation agreement on February 24, 1982 to commit $30 million to the Project. ESEERCO and Sohio Alternate Energy Development Company were non-equity contributors to the project, having signed contribution agreements on January 20, 1982, and April 10, 1984, respectively committing $5 million each to the Project. A $24 million project loan with a $6 million in-kind contribution by SCE of facilities at SCE's existing generating station in Daggett, California completes the $263 million funding.

A supply agreement was executed with Airco, Inc. on February 24, 1981 for Airco to provide "over-the-fence" oxygen and nitrogen from a new on-site facility, thus reducing capital requirements of the Project.

The Project applied to the United States Synthetic Fuels Corporation (SFC) for financial assistance in the form of a price guarantee in response to the SFC's first solicitation for proposals. This was designed to reduce the risks of the existing Participants during the initial demonstration period. The Project was not accepted by the SFC because it did not pass the "credit elsewhere" test (the SFC believed sufficient private funding was available without government assistance). However, the sponsors reapplied for a price support under the SFC's second solicitation which ended June 1, 1982. On September 17, 1982, the SFC announced that the project had passed the six-point project strength test and had been advanced into Phase II negotiations for financial assistance. On April 13, 1983 the sponsors received a letter of intent from the SFC to provide a maximum of $120 million in price supports for the project. On July 28, 1983 the Board of Directors of the SFC voted to approve the final contract awarding the price guarantees to the project.

A spare quench gasifier, which has been added to the original facility to enhance the plant capacity factor, was successfully commissioned in April 1985.

A Utah bituminous coal was utilized as "the Program" coal was burned at all times that the facility was not burning an alternate test coal. The Program could test up to 8 different coal feedstocks on behalf of its Participants companies.

A 32,000 ton Illinois No. 6 coal (nominal 3.1 percent weight sulfur) test, a 21,000 ton Pittsburgh No. 8 coal (nominal 2.9 percent weight sulfur) test, and a 20,000 ton Australian Lemington high-ash-fusion-temperature coal (nominal 0.5 percent weight sulfur) test were completed. Energy conversion rates and environmental characteristics while running the alternate coals are essentially the same as those observed while burning the low sulfur Utah bituminous.

The gasifier was started up on May 7, 1984. On May 20, 1984 syngas was successfully fed to the gas turbine and the first combined cycle system operation was accomplished on May 31, 1984. On June 23, 1984 the ten continuous day SFC acceptance test was successfully completed and the Program was declared to be in commercial production on June 24, 1984.

At the completion of the demonstration program in January 1989 the gasifier had been on-line for more than 27,116 hours, and gasified over 1,132,000 tons of coal (dry basis). Approximately 2.8 billion gross kWh of electricity was produced.

In September, 1989 Texaco Inc. announced that Texaco Syngas Inc., its wholly owned subsidiary, had been awarded the rights to negotiate with Southern California Edison for the purchase and operation of the Cool Water plant.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

Texaco intends to utilize a new application of Texaco's technology which will permit Cool Water to convert sewage sludge to useful energy by mixing it with the coal feedstock. Sewage sludge has been disposed of for many years in landfills and by ocean dumping, methods that are now becoming unacceptable for either overcapacity or environmental reasons. Texaco has demonstrated in pilot studies that sludge can be mixed with coal and, under high temperatures and pressures, gasified to produce a clean synthesis gas. Texaco officials emphasize that its gasification process results in no harmful by-products.

Acquisition of the plant is conditioned upon finalizing the terms of the purchase agreement and the completion of negotiations with SCE for the sale of electricity to be produced at Cool Water. 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 Cool Water plant for modifications aimed at reopening the facility in late 1992.

Project Cost: $263 million

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 has been sponsored by the European Economic Community (EEC) under two separate demonstration grants. Results to date have 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 have been 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 calorific values up to 7.5 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. The aim was to develop a range of commercial gasifiers with a coal throughput typically of 24 to 100 tonnes per day. 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 in the United Kingdom process industries.

Although OSC has yet to build the first commercial unit, they say interest has been shown from a large number of potential clients worldwide.

The application of the process for power generation is also being investigated. Various cycles incorporating a pressurized version of the spouted bed technology have been studied and power station efficiencies up to 45 percent are predicted. A contract with the EEC to develop a pressurized version was initiated in January 1989. The proposal is to link the gasifier to a char combustor to form what is known at the British Coal topping cycle.

CRIEPI ENTRAINED FLOW GASIFIER PROJECT — Central Research Institute of Electric Power Industry (Japan) (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 has been determined to be employed as the prototype of the national 200 ton per day pilot plant. As of late 1989, the gasifier had been operated for 1,652 hours, and tested on 17 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/sturry), oxidizer (air/oxygen) and gas cleanup methods (hot-gas/cold-gas). The optimal plant sys-
COMMERCIAL AND R&D PROJECTS (Continued)

... 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. Tests will be beginning in 1991 for the air-blown pressurized entrained-flow gasifier connected with the hot gas cleanup system and a high temperature gas turbine of 1,260°C combustor outlet temperature.

Project Cost: 53 billion yen

DANISH GASIFICATION COMBINED CYCLE PROJECT – Elkraft (C-205)

The Danish Utility, Elkraft, in response to government directives to lower pollution by using more natural gas, says that it will increase the use of natural gas to generate electricity. However, the utility says that it also plans for two power plants based on integrated coal gasification combined cycle (IGCC). The first will be a 50-megawatt demonstration unit at Masnedoe, at the site of an existing power plant that will be retired.

The Danish energy minister was expected to decide by 1990 whether to approve this scheme.

If the Masnedoe demonstration is successful, Elkraft intends to move on to construct a full-scale 300-megawatt IGCC unit at Sittakcea, for service in 1997.

It is not known which IGCC design Elkraft favors for the Masnedoe demonstration.

Potential bidders could include Shell, Dow, Texaco and Krupp-Koppers.

DANISH GASIFICATION COMBINED CYCLE PROJECT – Elsam (C-206)

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. 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 Sonderjylland Hojspeedningvaerk.

Commissioning is planned for 1995.

DELWARE 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 of 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)
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

DOW SYNGAS PROJECT – Louisiana Gasification Technology, Inc. a subsidiary of Destec Energy, Inc. (C-210)

The Dow Syngas Project, located in Plaquemine, Louisiana, began commercial operations in April, 1987, operating at rates up to 105 percent of capacity. As of July 1991 the project has completed 18,718 hours on coal. It has produced 20,355 billion BTU of on-spec syngas and has reached 1,524,712 tons of coal processed. A 90-day consecutive production record of 71.3 percent capacity was reached in October 1990. A 30-day consecutive production record of 94.3 percent was reached in the third quarter of 1991.

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-I acid gas removal system and Unocal’s Selectox sulfur conversion unit are also used at the Plaquemine, Louisiana, plant. 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. Therefore, if more than 150-200 megawatt capacity is needed, the plant can be built in phases as demand requires reducing the overall interest cost during the construction period versus building all of the capacity at the onset. 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 Dow Gasification 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-220)

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. The Federal Water Service Contract was to be approved in 1990. Operation of Phase I of the project is scheduled to begin in 1996.

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 calls for phased construction and operation, with initial construction (site preparation) beginning in 1992 and mechanical construction beginning in 1993 on a facility producing at one-half the full capacity. Commercial operation of this phase of the project is scheduled for 1996. Construction of the remainder of the facility is scheduled to begin in 1995 and to
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

be in commercial operation in 1998. This schedule 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: $2.2 billion (Phase I and II)
$0.2 billion (CO2 compression)
$0.1 billion (Pipeline interconnection)
$0.3 billion (mine)

ENCOAL LEC 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 SOx, 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. The principal machinery is being received and erected, all major subcontracts have been awarded and the contractors are on site. 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

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, SOx and NOx 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. This combination of equipment is able to produce electricity in a highly efficient manner.

Project startup is scheduled for late 1995.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

FRONTIER ENERGY COPROCESSING PROJECT - Canadian Energy Developments, Kilborn 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 fuel 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 Kilborn 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 (C₅—975 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 (AOCKT) and Gesellschaft für Kohleverflüssigung 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.

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 will begin by end-1991.

Project Cost: Not disclosed

GREAT PLAINS SYNFUELS PLANT - Dakota Gasification Company (C-240)

Initial design work on a coal gasification plant located near Beulah in Mercer County, North Dakota commenced in 1972. 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.
COMMERCIAL AND R&D PROJECTS (Continued)

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 137.5 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.

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 crescote 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 and other 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
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

GSP PILOT PLANT PROJECT – German Democratic Republic (C-250)

Since 1983 a 30 tonne per day gasification complex has been in operation at Gaskombinat Schwarze Pumpe (GSP) in East Germany. It produces more than 50,000 cubic meters of raw gas per hour. Practical results and experience gained during operation of this system are planned to be applied to the construction of a large-scale gas works, 5 to 10 times larger, with an annual output of 2 to 4 billion cubic meters raw gas.

The environmental compatibility of the GSP coal gasification process is said to meet the highest requirements even if coal that is rich in ash and sulfur and contains salt is used. The GSP process involves the gasification of pulverized coal under pressure, using the brown coal of the German Democratic Republic. Its mode of operation, however, is widely independent from the fuel, so that brown coal, hard coal, coke, high-ash coal, and so-called salt coal as well as waste products can be processed.

A combined cycle demonstration with an output of 150 megawatts is being considered at Geiseltal. The Geiseltal power plant burns high-salt brown coal characterized by a high Na₂O and K₂O content in the ash of more than 20 percent. Brown coal with such high salt contents cannot be fired in conventional power plants, because the low softening point of the ash results in severe contamination of the heating surfaces.

This project has been canceled.

Project Cost: Not disclosed

HOT GAS CLEANUP PROCESS – Southern Company Services, Inc. and United States Department of Energy (C-257)

Southern Company Services, Inc. of 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 cleanup techniques from laboratory research to integrated engineering tests. Actual gases from coal gasification or combustion will be used.

A vessel will be built to create coal gases for the tests, consuming up to 2 tons a day of coal to create particulate-laden hot gases in an amount similar to what would be produced from a 2 to 3 megawatt power plant. Gases typical of both high pressurized combustion and different methods of coal gasification will be produced.

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.

Design and construction of the test facility will take three years. 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

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 is scheduled 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 flows 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
- **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 researches are 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)

The Institute of Gas Technology (IGT) plans to build an experimental facility for its 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 formed 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.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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 will begin April 1, 1991 and will be completed September 30, 1994. Total estimated cost of the project is $22,700,000.

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 4,725,306, 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.

KANSK-ACHINSK BASIN COAL LIQUEFACTION PILOT PLANTS - Union of Soviet Socialist Republics (C-280)

The Soviet Union is building a large coal-based project referred to as the Kansk-Achinsk Fuel and Energy Complex (KATEK).

The project consists of a very large open pit mine (the Berezovskiy-1 mine), a 6,400 megawatt power plant, and a coal liquefaction facility. Additionally, the small town of Sharypovo is being converted into a city with new schools, stores, housing, and transportation.

A pilot plant referred to as an ST-75 installation is being built at KATEK to test a catalytic hydrogenation process. Construction of the unit began in 1982. Start up of the unit was originally planned for 1984, however, the plant has still not been completed. Preliminary tests indicate that five tons of Kansk-Achinsk brown coal can produce one ton of liquid products at a cost that is 25 to 30 percent less than products that are refined from crude oil from remote Siberian regions.

Additionally, a second unit referred to as the ETKh-175 is being built at a power station in Krasnoyarsk to test rapid pyrolysis of brown coal from the Borodinskoye deposit and is said to be nearing completion. The test unit will have a capacity of 175 tons of coal per hour. The plant is designed to crush the Kansk-Achinsk run of mine coal with 40 percent moisture in hammer mills and simultaneously dry the resulting coal dust with the flue gas from a special-type self-contained furnace. In the thermal reaction (pyrolysis) chamber, the dried coal dust heats up quickly to 550-700 degrees C as it mixes with a solid transfer agent (pulverized coke) circulating in the system and preheated to 850-950 degrees C in a process furnace. As the two mix during pyrolysis, the coal forms coke breeze and a mixture of combustible gas, resinous and pyrogenous water vapors. Upon dedusting in cyclone separators, the mixture is subjected to fast cooling whereupon it is fed to the gas cleaning and condensation plant.
COMMERCIAL AND R&D PROJECTS (Continued)

The excess coke breeze formed during pyrolysis is cooled down to 75-80 degrees C and is used as a commercial product.

The ETKh-175 energy efficiency is said to be about 85 percent, with account for the energy losses and auxiliary power. The plant will be supplemented with facilities for obtaining liquid tar resins, motor fuel and coal tar, various chemical products and for making coke breeze briquettes from a mixture of brown coal and coal tar.

A third experimental coal liquefaction unit, ST-5, is located at the Belkovskaya mine of the Novomoskovsk Coal Association. The unit is intended to demonstrate a relatively low pressure hydrogenation process that operates at approximately 1,500 psig and 400 degrees C. A catalyst is used in the process to enhance the hydrogenation of coal into high octane gasoline. The liquid and solid are separated, and the solids are combusted to recover the catalyst.

Project Cost: Not disclosed

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 use of the K-Fuel technology on coal only in North America was issued to the Heartland Fuels Corporation (HFC), an ENSERV subsidiary. HFC made application for funding to DOE under Round 4 of the Clean Coal Technology program. If funding is approved, construction of a 425,000 ton commercial plant will begin.

A new company, Smith Powerfuels, a partnership of K-Fuel Partnership and Energy America, has been established to develop an international market for K-Fuel.

Project Cost: $62 Million

KOBRa HIGH TEMPERATURE WINKLER IGCC DEMONSTRATION PLANT -- RWE Energie AG (C-294)

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 desulphurized 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 with 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 desulphurization unit, the coal drying unit and some other large components were placed in 1990. The permit procedure will be initiated in late 1991.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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.

KRW ENERGY SYSTEMS INC. ADVANCED COAL GASIFICATION SYSTEM FOR ELECTRIC POWER GENERATION – The M.W. Kellogg Co., United States Department of Energy, and Westinghouse Electric (C-310)

In April 1984 Westinghouse sold its coal gasification technology to Kellogg Rust and the new organization was named KRW Energy Systems Inc., owned 20% by Westinghouse and 80% by the M.W. Kellogg Company. The major activities of KRW Energy Systems has been to complete development of a fluidized bed coal gasification technology and to develop a commercial demonstration project.

The major development facility for KRW is a coal gasification pilot plant located at the Waltz Mill site near Pittsburgh, Pennsylvania. This facility started operation in 1975 and accumulated more than 12,000 hours of hot operation utilizing a broad range of coals. These coals include high caking Eastern bituminous, Western bituminous, and lignites with high and low ash contents and high and low moisture contents. A number of German brown coals have also been successfully gasified. The pilot plant program was completed in September 1988, and the facility has been decommissioned.

The pilot plant utilized a single stage fluidized bed gasifier with ash agglomeration and hot fines recycle. The pilot gasifier is operated at temperatures between 1,550 degrees F and 1,950 degrees F and pressures between 130 psig and 230 psig, with air feed to produce low-BTU gas and oxygen feed to produce medium-BTU gas. Pilot plant coal capacity ranged between 20 and 25 tons per day, depending on coal type.

The Department of Energy hot gas cleanup program that was initiated in late 1984 was also completed in fiscal year 1988. The results from this development program have provided significant cost and efficiency improvements for the KRW gasification technology as applied to gasification combined cycle electric power generation. Operations at the Waltz Mill pilot plant with an air blown gasifier using a high sulfur (2-4.5%) and highly caking Eastern bituminous coal, have achieved the following significant demonstrations:

- A simplified process to deliver a hot and clean low BTU fuel gas to a combustion turbine.
- Gasifier in-bed desulfurization to meet NSPS requirements by removing over 90% of feed sulfur utilizing limestone or dolomite sorbents.
- Utilization of a regenerable zinc ferrite sorbent in a sulfur polishing mode to reduce fuel gas sulfur levels to less than 20 ppm.
- Demonstrated use of sintered silicon carbide candle filters at 1,100-1,200 degrees F and 16 atm pressure to reduce fuel gas solid particulates to less than 10 ppm.
- Delivery of final product fuel gas at high temperature and pressure containing less than 1 ppm combined alkali and heavy metals.

Commercial scale process performance systems studies show the KRW hot gas combined cycle power system to have net heat rates less than 8,000 BTU/kWh and capital costs less than 1,250$/kWh for 300-400 MW sized plants. A significant feature of these systems is the modularity of design which provides much planning and construction flexibility.

Kellogg is interested in applying the KRW gasification technology to a commercial size demonstration plant of about 60 MWe capacity.

Project Cost: Not disclosed

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).

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STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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.


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 LIQUID PHASE METHANOL SYNTHESIS – Air Products & Chemicals, Chem Systems Inc., Electric Power Research Institute, and United States Department of Energy (DOE) (C-330)

Air Products is testing a 5 ton per day process development unit (PDU) located near LaPorte, Texas. The unit is being run as part of a program sponsored by DOE and will be used to evaluate the liquid phase methanol synthesis technology developed by Chem Systems. In the process, synthesis gas is injected in the bottom of a reactor filled with light oil in which a methanol synthesis catalyst is suspended. The oil acts as a large heat sink, thus improving temperature control and allowing the use of more active catalysts and/or a more concentrated synthesis gas.

Additionally, a wider range of synthesis gas compositions can be used, thereby allowing the use of low hydrogen/carbon ratio gases without the need for synthesis gas shift to produce more hydrogen. The technology is particularly suitable to syngas derived from coal in modern, efficient coal gasifiers which produce a high CO content syngas.

In spring 1985, the liquid phase methanol PDU was started, with the initial objective of a 40 day continuous run. During the run, the unit was operated under steady-state conditions using carbon monoxide-rich gas representative of that produced by advanced coal gasifiers. During the run, the plant achieved a production rate of up to 8 tons per day with a total production of approximately 165 tons of methanol (50,000 gallons). The plant, including the slurry pump and a specially designed pump seal system, apparently operated very reliably during the run.

In a four-month test lasting from September 1, 1988 to January 8, 1989, the unit produced methanol from simulated coal gas at a rate more than twice the original design rate of the test facility.

The LaPorte run lasted 124 days and was interrupted only briefly when Hurricane Gilbert threatened the Gulf Coast early in the test program. During the marathon operation, the experimental facility produced just over 8,000 barrels of fuel-grade methanol. Production rates averaged 60 to 70 barrels per day – roughly twice the facility's original 35-barrel per day design rate. Methanol from the test run was of high enough quality to be used directly as a motor fuel without further upgrading.

The 124-day run also demonstrated the effectiveness of improvements in the facility's reaction vessel which had been modified earlier to incorporate an internal heat exchanger and vapor/liquid separation process. Synthesis gas was provided by Air Products from its adjacent HyCO production plant. Operation of the PDU was again successfully tested from September 1989 through March 1990. The PDU was said to have operated extremely well with excellent productivity.

The 48-month, $10.2 million project was completed in March 1991.

Project Cost: DOE: $26.4 million
Private participants: $3.8 million

LIQUID PHASE METHANOL DEMONSTRATION PLANT – Texaco Syngas, Inc., Air Products and Chemicals, Dakota Gasification Company, Electric Power Research Institute (C-345)

Air Products and Chemicals, Inc. and Dakota Gasification Company (DGC) were selected by the United States Department of Energy (DOE) to negotiate for an estimated $93 million from the federal government to help underwrite the costs of a 500 ton-per-day liquid phase methanol unit the two companies jointly planned to construct at DGC's Great Plains Synfuels Plant in Beulah, North Dakota. The novel project, which is designed to lower power costs and reduce acid rain emissions, was one of 13 selected by the DOE under the third round of the nation's Clean Coal Technology Demonstration Program.
Coal Gasification Combined Cycle (CGCC) is the cleanest technology for generating electric power from coal. The liquid phase methanol technology that was originally planned to be demonstrated at the Great Plains facility has been developed specifically to lower the cost of electricity produced in CGCC power plants by efficiently storing energy in the form of methanol for use during periods of peak power demand. These types of facilities could also sell any excess quantities of the clean-burning fuel for other applications. CGCC can effectively repower coal-fired facilities and meet stringent environmental limits for sulfur dioxide and nitrogen oxide emissions. Thus, on a commercial scale, the liquid phase methanol technology could reduce electric power costs by allowing utilities to rely less on imported liquid fuels or natural gas and still meet the nation’s clean air requirements.

The project originally called for about 10 percent of the synthesis gas produced at the Great Plains plant to be converted to make 500 tons per day of methanol, while the remaining synthesis gas would be used in making substitute natural gas. However, it has been announced that the project will be located elsewhere. DCG said that a major reason for not being able to locate the project at Great Plains is the company could not get permission from its gas buyers to divert 10 percent of its synthetic natural gas to methanol production.

Texaco Syngas, Inc. is negotiating to buy the Cool Water plant in Daggett, California to house the project. Because of the project site change, DOE will allow more time to negotiate a cooperative agreement.

Project Cost: $213 million estimated

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, 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. When completed in mid to late 1991, the Lu Nan modification will replace 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 for conversion to coke in a continuous rotary hearth coker. The moisture and volatile hydrocarbons contained in the char 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 recondensed 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.

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STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (continued)

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.

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 yuan 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:

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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 (PDUs) 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.
COMMERCIAL AND R&D PROJECTS (Continued)

Project Cost: 100 billion yen, not including the three existing PDU

OUUL AMMONIA FROM PEAT PROJECT—Kemira Oy (C-450)

Kemira of Finland is building a pressurized fluidized bed peat gasification system for producing synthesis gas. The gas will be used for ammonia and other chemicals. Ammonia production is to be 80,000 tons per year.

Currently Kemira operates in Oulu a minor ammonia plant based on the gasification of heavy fuel oil. However, peat is the only realistic domestic raw material for synthesis gas in Finland. Therefore, a research program aiming at the gasification of peat was started in the middle of the 1970s.

The gasification plant includes as integrated individual processes: peat transfer, screening, crushing, drying, pressurized HTW fluidized bed gasification, soot removal, raw gas compression and three-stage gas purification. The existing Pyroflow boiler plant serves for energy supply and a waste incinerator. The gasification plant was placed in operation in June 1988. It has a capacity of 150 megawatts, thermal.

Project Cost: Investment costs are expected to be FIM225 million.

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 iron. 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, M.W. Kellog Company (C-459)

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 for use in other plants by outside contractors who do not have facilities for such testing. The facilities are scheduled to be completed by mid-1993.

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.

PREFNLO 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 tons per day demonstration plant and designing a 1,000 tons per day demonstration module for the PRENFLO (pressurized entrained flow) process. The PRENFLO process is KK's pressurized version of the Koppers-Totzek (KT) flow gasifier.

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.

Krupp Koppers and Siemens, KWU Group, are planning a demonstration IGCC plant based on the PRENFLO process. This demonstration plant will have a capacity of 160 megawatts, based on one PRENFLOW module with 1,200 tonnes per day coal throughput and two Siemens V64 gas turbines. The detailed engineering was to be finished in 1989, so that a contract can be awarded in the second half of that year. The startup of the plant is planned for 1992.

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/PGD 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 SO2 and NOx 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.
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 fur Eisenhutenkunde" 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 1985 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 38,000 hours of operation. The specific synthesis gas yield reached 1,580 standard cubic meters per tonne of brown coal (MAE) 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 specific fuel gas flow per square meter.

This work is performed in close co-ordination with Rheinbraun's parent company, the Rheinisch-Westfalisches 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.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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-hexene or 1-pentene will be built to come online in January 1994.

- Krypton and xenon gases will be recovered from the Secunda oxygen units.

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
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

SCOTIA COAL SYN FUELS 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 downsized 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. (HRI) 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 $23 million coprocessing feasibility study. The study was expected to be completed by June, 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 are continuing in 1991 with the governments of Canada and Nova Scotia and with corporations.

Project Cost: Approximately $2.5 million for the feasibility study
Approximately $350 million for the plant

SEP GASIFICATION POWER PLANT – SEP (C-520)

In 1989, 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 will be Buggenum, in the province of Limburg, The Netherlands.

The Siemens/KWU V94.2 gas turbine was chosen and tested to satisfaction using coalgas of the same composition as that from the Shell process.

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)

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.

SHOU GANG COAL GASIFICATION PROJECT – People’s Republic of China (C-523)

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.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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 requirements in the mid-1990s.

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-Wachtberg, 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

SYNTHESGasANLAGE RUHR (SAR) – Ruhrkohle Oel and 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 Synthesgasanlage Ruhr has been completed on Ruhrchemie's site at Oberhausen-Holten.

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 oxo-synthesis plants. As of 1989 the gasification plant was to be 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)
COMMERCIAL AND R&D PROJECTS (Continued)

TAMPELLA KEEER IGC PROCESS DEMONSTRATION – Tampella Keeer (C-965)

After having obtained the rights to the Institute of Gas Technology's fluidized bed gasification technology in 1989, Tampella Keeer began to design and initiate construction of a 10 MW thermal pilot plant at their research facilities in 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 papermill 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.

Tampella with the assistance of Stone & Webster Engineering Corporation is in the process of identifying a utility project in the United States to be the basis of an application for funding to the United States Department of Energy's Clean Coal Program. Thus far, the team has evaluated four different options which include a stand alone IGCC plant and repowering scenarios. Capital costs for these four options ranged from $141 million to $173 million.

TEXACO MONTEBELLO RESEARCH LABORATORY STUDIES – Texaco Inc. (C-971)

Texaco has a number of on-going 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.

While a major purpose for MRL is carrying out the research and pilot plant testing needed in the development of the Texaco Gasification Process (TGP), the pilot units are used also to obtain data required for the design and environmental permitting of commercial plants. Currently a major focus at Montebello is a five year cooperative agreement with the United States Department of Energy to develop and demonstrate the integration of hot gas cleanup with TGP-based coal gasification-electric power generation. The program calls for investigating, both technically and economically, in-situ and external hot gas desulfurization. The most promising of these will be demonstrated, along with other hot gas cleanup steps, in an integrated pilot unit.

The program consists of five phases and will continue Phase II in 1991. These include: Phase I - Preliminary Desulfurization Research, Phase II - Process Optimization, Phase III - Integrated Pilot Demonstration Unit (PDU) Design, Phase IV - Integrated System Commissioning, and Phase V - Integrated PDU Tests.

Phase II work completed as of year end 1990 includes the evaluation of in situ sorbents using air-blown gasification instead of oxygen-blown gasification, the evaluation of a number of mixed metal oxide sorbents using external fixed beds, and the evaluation of slurries of calcium-based sorbents.

UBE AMMONIA-FROM-COAL PLANT – Ube Industries, Ltd. (C-990)

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 1980. 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
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

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.

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

VIRGINIA IRON COREX PROJECT – Virginia Iron Industries Corp. (C-613)

In 1990, Virginia Iron announced it would be the first United States industry to use the COREX coal gasification technology, a German steel manufacturing process integrated with power generation. The plant will be very similar to the ISCOR plant installed in 1989 in Pretoria, South Africa, but will be located in Hampton Roads, Virginia.

SYNTHETIC FUELS REPORT, DECEMBER 1991
The plant will produce a total of 340 megawatts, of which 130 megawatts will be used in the plant's gasification process and 210 megawatts will be sold to Virginia Power. The $800 million project is scheduled to come on line in 1994 with full operation beginning in 1995.

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 C$1 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. When complete in mid 1991, the feasibility study will also identify the plant site and operator.

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.

Operation of the facility could begin as early as 1996.

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 Scoria Inc., a subsidiary of NRG, Northern States Power's 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.

The ACCP demonstration facility is under construction and is currently scheduled to begin startup during the last quarter of 1991. Initial product test burns are scheduled during the first quarter of 1992. 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.

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 stages.

The study was completed and evaluated. Bechtel was paid from a $600,000 grant to SCCP from the United States trade and development program, International Development Cooperation Agency.
STATUS OF COAL PROJECTS (Underline denotes changes since September 1991)

COMMERCIAL AND R&D PROJECTS (Continued)

The Phase I design has been revised to produce one million cubic meters of town gas per day and 20,000 tons of formic acid per year. Its feasibility study was submitted by Shanghai Municipality in December of 1990 to the Chinese National Planning Commission for approval. Its early stage work will begin in 1991. The original Phase I design which was approved by the Chinese National Planning Board in 1989 called for the production of 100,000 tons of methanol and 15,000 tons of cellulose acetate per year.

Phase I is scheduled for startup in the first half of 1994 and will cost 545 million yuan. In Phase I, the plant will consume 500,000 tons of coal per year.

Project Cost: 2 billion yuan

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.
## COMPLETED AND SUSPENDED PROJECTS

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SYNTHETIC FUELS REPORT, DECEMBER 1991
NEW ZEALAND SYNFUELS PRODUCES RECORD 6-MONTH OUTPUT

According to the annual report from Fletcher Challenge, Ltd., the Motunui synfuels plant in New Zealand produced a record 562,000 tonnes of gasoline in the first 6 months of 1991. In addition, a percentage of crude methanol was pipelined to Fletcher's Petralgas plant to produce 186,000 tonnes of chemical grade methanol.

Fletcher Challenge is the plant's majority owner since taking over from the government. Mobil, which holds a 25 percent share of the Motunui plant, operates the facility.

The company is expecting a strong demand for gasoline in the Asia-Pacific area, and therefore has begun producing its first regular grade of oil and high octane gasoline.

Fletcher Challenge will reportedly exercise its option to require the government to buy NZ$400 million (US$222 million) of new shares from the company. This option was part of the deal negotiated in 1988 when Fletcher Challenge bought Petrocorp. Government officials, saying that the government does not want to be a major player, say the shares will eventually be resold.

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SYNTHETIC FUELS REPORT, DECEMBER 1991
DOE OUTLINES PROPOSALS TO HELP GAS INDUSTRY

United States Department of Energy (DOE) Deputy Secretary W.H. Moore has outlined a series of proposals to encourage the use of natural gas as an alternative to imported oil. Speaking before the Southern Gas Association in Orlando, Florida, Moore highlighted initiatives proposed in the National Energy Strategy and in Senate energy bill S.1220, including working aggressively with state regulators and switching of federal facilities from imported oil to natural gas.

"The Department of Energy plans to work closely and aggressively with state regulators to encourage efficiency and expansion of gas markets. That is why we are announcing today a joint DOE-National Association of Regulatory Utility Commissioners (NARUC) Conference to be held in Phoenix, Arizona, February 3-5, 1992. We are also looking at the feasibility of switching federal facilities from imported oil to alternative energy sources like natural gas. All of DOE's facilities, except one which is in the process of switching, have already switched," Moore said.

In addition to the DOE-NARUC Conference and the switching of federal facilities from imported oil, DOE will:

- Restructure its own gas research and development program
- Accelerate the conversion of the federal fleet to alternative fuels such as compressed natural gas
- Work with industry to identify and eliminate obstacles to long-term contracts
- Work aggressively with the Federal Energy Regulatory Commission on reform issues
- Work harder to educate the public about the reliability and availability of natural gas supplies

Moore went on to say, "I believe that the long-term future of natural gas depends on three key initiatives of the National Energy Strategy: Public Utility Holding Companies Act reform, pipeline construction reform, and an increase in the use of alternative fuels. The increased use of natural gas is in danger because the Senate refused to consider the energy bill proposed by Senators Johnston and Wallop."

GAS-FIRED LIQUEIFIER GETS SBIR AWARD

A Small Business Innovation Research (SBIR) grant was awarded to General Pneumatics Corporation of Scottsdale, Arizona for a gas-fired liquefier for natural gas recovery from remote locations. The grant was awarded under Phase I of the 1991 SBIR program, administered by the United States Department of Energy, in the amount of $49,790. Of the 1,401 grant applications received in response to the ninth annual solicitation in 1991, 173 Phase I projects were selected.

This project consists of a mobile, self-contained, gas-fired natural gas liquefier system for the economic recovery of natural gas from "capped" wells in remote locations. The system is an innovative arrangement of multiple, truck-mounted Stirling liquefier modules that liquefy methane for recovery from the wellhead gas while utilizing the heavier fractions of the natural gas for combustion to power the system. By deriving power from wellhead gas to liquefy methane, the system facilitates the refinement and transport (by tank truck) of natural gas from well sites for which provision of a pipeline and electric power or diesel fuel is impractical.

The liquefier module is a compact arrangement wherein a four-cylinder, double acting Siemens-Stirling engine powered by gas combustion drives a second four-cylinder, double-acting Siemens-Stirling cryorefrigerator capable of liquefying methane. The engine and refrigerator are coupled by a common drive linkage that gives the pistons optimum phasing with straight-line motion to minimize side forces and wear. The system uses helium as the working fluid and is cooled by recirculating water. A switching recuperative heat exchanger is used to precool the wellhead gas and separate out the "heavy ends" for combustion prior to liquefaction of the methane.

The prototype design under development in Phase I is for a refrigeration capacity of 4 kilowatts at 110K to liquefy 16 kilograms of methane per hour. This unit will serve as a scaled-down, test-bed prototype for an eventual 80 kilowatt Siemens-Stirling natural gas liquefier for field application.

Potential Commercial Applications

The natural-gas-fired methane liquefier system could provide the means for economic recovery and utilization of natural gas from otherwise unproductive "capped" wells in remote locations. It may also be adapted to the useful recovery of "methane drainage" from coal fields. Liquefaction of the natural gas facilitates gas transport and may help producers
to promote natural gas as a fuel for government, commercial, and private automotive fleets; for mass transportation; and for railway, marine, construction, and agricultural engines.

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SYNTHETIC FUELS REPORT, DECEMBER 1991

5-3
LIQUID FUELS FROM NATURAL GAS SHOULD BE COMPETITIVE AT OIL PRICES OF $25 TO $30

The outlook for liquid fuels from natural gas was reviewed by G. Pyke of Chem Systems, London, United Kingdom at a symposium in The Netherlands in October. Pyke’s remarks were featured in a special supplement of European Chemical News. According to Pyke, petrochemical firms are committing substantial amounts of research and development spending to developing technologies to convert gas feedstocks into useful chemicals, notably lower olefins, fuels and aromatics. With such intense research, a breakthrough in one of the current technologies is likely in the next 2 decades.

At present, only around 6 percent of natural gas resources are used as feedstock either in bulk or by conversion of natural gas liquids. Bulk conversion of natural gas, predominantly methane, is mainly to syngas which is used in the production of methanol and ammonia. However, Shell, BP, Sasol, and Badger, among others, have developed processes to convert syngas to higher hydrocarbons via Fischer-Tropsch type reactions.

The conversion of methane to new products is a goal being pursued by several companies. Avenues include the oxidative coupling of methane to olefins (ARCO, Phillips Petroleum, Union Carbide and IFP), olefins oligomerization to gasoline and diesel (Mobil), methanol synthesis (Air Products, Mitsubishi), methanol to olefins (Mobil, BASF, Union Carbide), direct oxidation to methanol/formaldehyde, cracking to acetylene/ethylene (IFP) and chlorination / cracking to acetylene/ethylene (BP).

With respect to methane conversion to transport fuels, Pyke points to research such as methanol via syngas, synthetic gasoline via methanol dehydration (Mobil), synthetic gasoline/diesel via Fischer-Tropsch reactions (Shell, Sasol) and via olefins oligomerization (ARCO, BP, Mobil, and Shell).

Mobil has already built a plant using its methanol-to-gasoline process in New Zealand. Sasol is currently building a plant for a Fischer-Tropsch process to convert natural gas-derived syngas into gasoline and olefins at Mossel Bay, South Africa. At the same time, Shell is building the first plant to use its Shell middle distillates synthesis (SMDS) process in Malaysia.

A Chem Systems analysis of the Mobil process found that for a 500,000 tonne per year methanol-to-gasoline plant using first-generation technology in an Arab Gulf location and gas supplied at $0.50 per million BTU, the estimated full cost of production corresponds to a crude oil price of around $40 per barrel. However, if capacity is scaled up to 2 million tonnes per year and with further process refinement, the process is likely to be economic at oil prices of $30 per barrel.

A similar analysis of the SMDS process found that for a first-generation 500,000 tonne per year plant in an Arab Gulf location and gas supplied at $0.50 per million BTU, the process is again only likely to be economic at oil prices of $30 per barrel. Developments that are expected to improve the prospects for the SMDS process include scaleup, use of fluid bed reactors, rather than the presently used multiple fixed bed Fischer-Tropsch reactors, and the availability of lower-cost syngas.

The overriding determinant for the success of all the technologies will be the comparative price of crude oil. Pyke concludes that with price levels of $25 to $30 per barrel likely in the late 1990s, the potential for new gas technologies is expected to increase significantly.

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SYNTHETIC FUELS REPORT, DECEMBER 1991
TECHNOLOGY

EXXON DEVELOPS NEW PROCESS FOR SYNTHETIC LIQUIDS FROM GAS

Exxon says that it has recently completed a 10-year, $100 million research and development program which has resulted in a new process to make synthetic liquid fuels from natural gas. Natural gas is first converted to a synthesis gas (a mixture of carbon monoxide and hydrogen), then to an intermediate hydrocarbon product, and finally to a high-quality liquid. The liquid product is suitable for use as a refinery feedstock, a range of end-use fuel products, petroleum specialty and petrochemical products, or any combination of these, depending on local market conditions.

The company says that its gas-to-liquid conversion technology is at the leading edge of such efforts by the petroleum industry. It features exceptionally high-performing catalyst systems and advanced reactor designs that, together, produce higher yields of intermediate product for upgrading—and at less cost—than any other known process either in use or under development. More than 100 United States patents have been issued or allowed on this technology since its beginnings in the early 1980s.

According to company spokesmen, the new conversion process approaches in technological stature Exxon's development of fluid catalytic cracking some 50 years ago. "Gas conversion technology has the potential to be that important to the petroleum industry, as well as to Exxon," says C. Eidt, vice president for petroleum and synthetic fuels research at Exxon Research and Engineering Company.

Proprietary catalysts have been defined, manufactured by commercial vendors and tested for each step of the process. Pilot-scale testing of major components and the basic chemistry have been completed. Currently, a demonstration plant at Baton Rouge, Louisiana is providing the remaining data required to design and construct a commercial-scale gas conversion facility.

The new process was developed especially for gas discovered in remote areas of the globe which are not economically accessible by conventional transportation methods. Of the world's estimated 3,800 trillion cubic feet of discovered gas reserves, roughly half are located in remote areas—not close to any sizeable market—and are uneconomic to move long distances at today's price levels. Exxon holds the rights to significant quantities of remote gas and thus has a strong incentive to find new ways to bring these resources to markets more economically. The new gas-to-liquids technology opens an additional dimension for potential exploitation of remote gas. Having the ability through the new technology to convert gas into a variety of liquid forms will provide more options in dealing with local market conditions in different parts of the world.

Still, Exxon says, this new technology must first break through an economic threshold before becoming commercially feasible. The cost of constructing commercial-size gas conversion plants in remote areas will be very high. Depending on the location of a specific remote gas reservoir and the cost to produce it, oil prices will have to grow to a level higher than today's before liquids produced from the new process will be competitive.

"This technology will be applied selectively, but we could see the first commercial plant around the turn of the century," says F. Voigt, vice president for gas at Exxon Company International.

The process involves three distinct steps—each requiring its own technical advances.

In step one, natural gas is converted to a syngas. In this stage, Exxon uses a unique fluidized bed reactor system to obtain higher efficiency and better economy of scale than alternative approaches to producing syngas.

In step two, hydrocarbon synthesis (HCS), the syngas is converted to an intermediate liquid hydrocarbon product. Exxon's HCS technology features both a high-performance catalyst system and an advanced reactor design. Taken together, these features are said to provide significant yield and cost advantages over competitive technologies.

In step three, the intermediate hydrocarbon products are upgraded in a step similar to conventional refinery hydrotreating. Proprietary catalysts designed to produce high-quality refinery feedstock or finished products also are used in this step.

One of the biggest problems was perfecting the HCS reactor in which syngas is converted to a hydrocarbon product. Initially, Exxon's team demonstrated that the HCS step could be conducted in a conventional fixed-bed reactor system where catalyst is packed inside thousands of tubes. Later, in a major departure from prior industry practice, an advanced reactor and catalyst system was devised that raises HCS yields and reactor throughput by a substantial margin.

In the HCS step, a considerable amount of heat is released as the syngas is converted to the intermediate hydrocarbon product. Engineers had to devise a method to remove the heat so that it could be used efficiently in other parts of the plant.

Another area of major interest was determining how the behavior of the complex HCS system—involving solid, liquid and gaseous phases—would change with various reactor designs and scaleup.

SYNTHETIC FUELS REPORT, DECEMBER 1991
The Baton Rouge gas conversion demonstration plant now operates around the clock for up to several months at a stretch providing the information on equipment and catalyst performance, materials and overall system performance needed to design, build and operate a future commercial-scale unit.

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NEW METHOD DISCOVERED FOR CONVERTING METHANE TO HIGHER ALKANES

Researchers at the University de Nancy in France believe they have found the right catalyst and process conditions to enable direct conversion of methane to higher alkanes.

The researchers used a commercial platinum catalyst, Europt-1, and a low temperature technique which they believe is a new route to producing higher alkanes. The catalyst was placed in a U-tube. At a temperature in the range of 150 to 280°C, methane was passed over the catalyst, resulting in evolution of both ethylene and hydrogen. The amount of ethylene produced was about 1 order of magnitude less than the amount of hydrogen produced.

Carbonaceous residues were accumulating on the catalyst surface producing a chemisorbed film. Subsequent flushing with hydrogen resulted in rapid production of higher hydrocarbons, going up to C$_7$.

The researchers say that a key factor in the experiment was the continuous removal of hydrogen by flowing methane during exposure of the catalyst. They say that efficient hydrogen removal allowed appreciable amounts of hydrogen-deficient species to build up on the surface. The researchers pointed out two advantages of the process: the low temperatures used and the ability to recycle the methane.

###
GAS PRODUCTION AND RESERVE ADDITIONS UP IN 1990

The American Gas Association (AGA) reports that natural gas production in 1990 rose slightly more than 1 percent over 1989 levels, reaching its highest level since 1984. Gas imports, primarily from Canada, reached a record level of 1.4 trillion cubic feet. However, gas well completions in 1990 decreased by 18 percent as compared to 1989.

By year end 1990, total proved reserves were 169.3 trillion cubic feet, up by 1.3 percent from the 167.1 trillion cubic feet reported for 1989. (See Table 1.) Replacement of natural gas production by reserve additions was 108.9 percent in 1990, compared to the 10-year average of 94 percent of production.

Figure 1 depicts the past 10-year history of proved recoverable reserves and net production of natural gas in the United States. Figure 2 compares net production of natural gas to total discoveries and reserve additions of natural gas for the past 10 years in the United States.

The average retail natural gas price increased by 2 percent in 1990 compared with 1989 prices.

TABLE 1

RESERVES AS OF DECEMBER 31, 1990

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<thead>
<tr>
<th></th>
<th>1990</th>
<th>% Change 90/89</th>
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<tr>
<td>Natural Gas</td>
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<tr>
<td>(Billions of cubic feet)</td>
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<tr>
<td>Total Proved Reserves</td>
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<td>% of Non-Assoc., Est.</td>
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<td>% of Assoc.-Dissolved, Est.</td>
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<tr>
<td>Underground Storage</td>
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<tr>
<td>Total Discoveries</td>
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<tr>
<td>Production</td>
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<tr>
<td>Natural Gas Liquids</td>
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<tr>
<td>(Millions of barrels)</td>
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<tr>
<td>Total Proved Reserves</td>
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<td>Total Discoveries</td>
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<tr>
<td>Production</td>
<td>732</td>
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<tr>
<td>Crude Oil</td>
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<td>(Millions of barrels)</td>
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<td>Total Proved Reserves</td>
<td>26,254</td>
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<tr>
<td>Total Discoveries</td>
<td>689</td>
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<tr>
<td>Production</td>
<td>2,505</td>
<td>-3.1</td>
</tr>
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</table>
STATUS OF NATURAL GAS PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since September 1991)

FUELCO SYNHYTECH PLANT – Fuel Resources Development Company (FRC) (G-10)

Fuel Resources Development Company (FRC) 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 FRC, a wholly owned subsidiary of Public Service Company of Colorado, and Rentech Inc. of Denver, Colorado. FRC 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 230 barrel per day production rate for about 20 years.

Project Cost: $16 million

MOSSGAS SYNFUELS PLANT – South African Central Energy Fund (50%), Gencor (30%), and Industrial Development Corporation (IDC) (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 scheduled to be completed in 1991.

Detailed engineering of the onshore plant is completed and construction is scheduled for completion in mid-1991. The complex is expected to be in full production by mid-1992. The product slate will be liquefied petroleum gas, 93 and 97 octane gasoline, kerosene and diesel.

Assuming Mossgas is given the same incentives as Sasol, the breakeven point for the project will be reached with crude oil prices of $20 per barrel.

Project Cost: $3.1 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 6 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.

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 1989 the plant produced about 4,100 tonnes of methanol per day to be converted into about 12,700 gallons of gasoline per day.

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.

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 Petrogas plant to produce 160,000 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.

Project Cost: $16 million

SYNTHETIC FUELS REPORT, DECEMBER 1991
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.

Project Cost: $660 million