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report

OIL SHALE  ♦ COAL  ♦ OIL SANDS  ♦ NATURAL GAS

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IGT Highlights Research Efforts in Natural Gas and Coal Conversion

The Institute of Gas Technology (IGT) has described energy and environmental work in its 1993 Annual Report (see page 1-1). Various projects were discussed, including work with molten carbonate fuel cells, IMHEX technology, U-GAS coal gasification, RENUGAS biomass gasification, the MILDGAS process, and natural gas processing.

Clinton Administration Releases Domestic Oil and Gas Plan

In December, the Clinton Administration released *The Domestic Natural Gas and Oil Initiative*, designed to increase the energy efficiency and competitiveness of United States industry and reduce the trend toward higher oil imports. As seen in the article on page 1-3, emphasis is placed on developing natural gas resources and environmental protection. Except for developing the oil and gas potential of Naval Oil Shale Reserves, little mention is made of synthetic fuels.

National Research Council Makes Recommendations for DOE Fossil Energy Research

A National Research Council study on the funding of research into fossil energy, including both upstream and downstream technology, is summarized on page 1-5. Heavy hydrocarbon processing, natural gas conversion, oil shale development, oil extraction from tar sands, and coal liquefaction were included. Recommendations were made for future funding priorities.

World Energy Council Foresees Big Increase in Energy Demand by 2020

A World Energy Council Commission has studied world energy consumption, considering economic, technical, environmental, social and institutional factors. The Commission developed four global energy cases, with each representing different assumptions in terms of economic development, energy efficiencies, technology transfer, and the financing of development worldwide. As summarized on page 1-12, a large increase in global energy consumption is forecast, especially in the developing countries.

Bechtel Sees Need for 100 GW of New U.S. Generating Capacity in Next 10 Years

Bechtel has given an overview of United States electricity markets through the year 2003, as reviewed on page 1-17. Bechtel predicts a base 2.0 percent per year average increase in peak electricity demand, leading to a need for 100 gigawatts of new generating capacity by 2003. Natural gas is expected to be the preferred fuel for the near term, with coal consumption increasing near the end of the forecast period.

Attractive Subsidies are Available for Biomass Gasification

Several tax benefits and subsidies exist for the production of energy from biomass, as discussed on page 1-20. The credits, benefits, and subsidies considered include a tax credit for producing gas from biomass, credit for producing electricity from biomass, incentive payments for electricity produced from biomass, benefits for alcohol fuels, accelerated depreciation on equipment, and tax-exempt financing.
Finnish Companies Making Progress in Pressurized Gasification

Finnish enterprises are developing pressurized gasification technology for power production from coal and biofuels, as discussed on page 1-25. Enviropower tests gasification fuels (coal and wood-based biomass) in its 15-megawatt pilot plant in Tampere, and is developing other projects as well. In addition, the A. Ahlstrom Corporation is working with Sweden’s Sydkraft AB on the Varnamo pressurized biomass gasification plant.

Byproduct Market Possibilities Examined for Eastern Oil Shale

Both established and potential oil shale product and byproduct markets for Eastern United States oil shale are examined on page 2-3. These include trace elements, sulfur, cement, asphalt, bricks, fixed gases, specialty carbon fibers, chemicals, and chemical feedstocks. Market evaluations are based for the most part on yields of byproducts expected from an Eastern United States shale processed with KENTORT fluidized-bed technology in a 7,500-short-ton per day plant.

New Opportunities Seen for High-Value Chemicals From Shale

The importance of developing ways to produce high-value chemicals and materials from oil shales, coals, and the liquids derived from them is considered on page 2-8. Examples of advanced, high-value chemicals that could be derived from oil shales or coals are described. Especially noted are heat-resistant high-temperature polymers.

Oil Shale Resources of the Pripyat Basin in Byelorussia Defined

The total area of the Pripyat oil shale basin, in Southern Byelorussia, has been estimated at 20,000 square kilometers, and the total reserves are estimated at 11 billion tons. Two principal deposits, the Turovo and the Lyuban, have been delimited, with total reserves of 3.6 billion tons. See page 2-12.

Baltic Oil Shale Basin Reviewed

The Baltic oil shale basin is located in Northern Estonia and it extends eastward into Russia, as reviewed on page 2-13. The basin has been divided into the Estonia and Leningrad fields; the Estonia deposit is the largest commercially exploited oil shale deposit in the world. Particular attention is given to the geology of the area.

Steam Retorting and Coprocessing with Lignite Studied for Turkish Oil Shales

Fixed-bed steam pyrolysis and fluidized-bed steam pyrolysis systems for processing oil shale are discussed on page 2-15, and experimental results are presented. Coprocessing of shale oils with lignite is also discussed.

Estonian-Finnish Seminar Makes Recommendations for Estonian Energy Development

A joint Estonian-Finnish seminar was held in September to analyze the state of the Estonian energy economy, as reported on page 2-16. Proposals were made to continue developing the oil shale industry and the electric power industry in Estonia.

Canadians to Pool Resources for Oil Sands R&D

The Canadian Oil Sands Network for Research and Development (CONRAD) has been formed to foster research that will improve the competitiveness of the Canadian oil sands industry. As
reported on page 3-4, a major goal of CONRAD is to increase the oil sands and heavy oil share of Canadian oil output to as much as 50 percent of the total within 15 years. The consortium also aims to reduce production costs to well below C$15 per barrel by 2002.

In Situ Combustion in Canadian Heavy Oil Reservoirs Reviewed

The field performance of some of the approximately 30 in situ combustion projects that have been or continue to be operated in Canada is reviewed on page 3-8. Laboratory combustion tube tests are also discussed, and laboratory results are compared with those from field tests. In light of the good agreement between field results and laboratory results, it was concluded that field operating procedures can be developed to realize the theoretical advantages of the combustion process.

Supercritical Fluid Extraction of Oil Sand Bitumen Studied

Supercritical fluid extraction of PR Spring bitumen, from Utah oil sands, was carried out using propane as the solvent. The objectives of this study, reviewed on page 3-11, were to determine the effects of temperature and pressure, to determine the chemical composition of the residual fractions, and to determine the extent of asphaltene rejection.

Steam-Assisted Gravity Drainage Becoming Proven Technology for Oil Sands and Heavy Oil

Steam-Assisted Gravity Drainage (SAGD), as described on page 3-13, is a process in which steam is introduced into growing chambers, and heated oil drains down to horizontal wells below. In SAGD, even the heaviest of bitumens can be produced without extensive preheating, and high recoveries can be obtained. The process has been demonstrated in Canadian field trials.

Heavy Oil Potential In Alaska Studied

The feasibility of heavy oil recovery--production, marketing, transportation and refining--in Alaska has been studied. It was concluded that little of the heavy oil in Alaska is likely to be developed without significant economic incentives. Even then, the costs may make Alaskan heavy oil unable to compete with heavy oil from other parts of the world. See page 3-18 for details.

Carbonate Fuel Cell Being Tested in Slip Stream at Destec Gasification Facility

A 30-kilowatt carbonate fuel-cell pilot plant is being subjected to a 4,000-hour endurance test, as reported on page 4-6. The ability of the fuel cell to operate on syngas from a Destec coal gasification plant is of particular interest.

MITRE Finds Direct Liquefaction More Economical Than Indirect

MITRE has studied technologies and economics for producing liquid transportation fuels from coal, through direct and indirect liquefaction. Economic analyses, discussed on page 4-12, indicate a required selling price of $40.01 per barrel for fuel produced through direct liquefaction and a required selling price of $45.60 per barrel for indirect liquefaction.

IGCASH Cycle Shows Promise for Intermediate Load Applications

The technical and economic merits of the Integrated Gasification Compressed Air Storage with Humidification (IGCASH) power cycle were assessed as described on page 4-14. Performance and cost data were developed for a generic IGCASH plant (400 to 500 megawatts) that can serve as a stand-alone intermediate-load coal-based powerplant. A comparison between the IGCASH
and a cycling pulverized coal-fired steam reference plant showed the IGCASH plant to offer better performance with lower costs.

**Baseload Power Generation Technologies Compared by Black and Veatch**

Commercially available coal and natural gas-fueled generation alternatives which can be expected to provide baseload capacity in the year 2000 were analyzed by Black and Veatch. Plant operations were described, environmental controls and their costs were considered, and overall comparative economic analyses were performed. See page 4-16 for details.

**History of Dispersed Catalysts in Coal Liquefaction Reviewed**

Researchers at the Kentucky Center for Applied Energy Research recently reviewed the history of dispersed catalysts in coal liquefaction. Developments from the first recorded use of catalysts (hydroiodic acid) by Berthelot in 1869 to current work with iron-based catalysts are covered (see page 4-22).

**Hot-Gas Particulate Removal Systems Studied for IGCC Applications**

Types of hot-gas particulate removal devices being considered for use in integrated coal gasification combined cycle systems are reviewed on page 4-24. These devices include the candle filter, Asahi ceramic tube filter, ceramic cross-flow filter, granular-bed filter, and ceramic fabric filter. The candle filter was favored for gasifier hot-gas cleanup.

**Aromatic Polymer Precursors Could Provide a New Direction for Coal Chemicals**

The potential for using coal as a feedstock to produce aromatic precursors to specialty chemicals and advanced polymers is discussed on page 4-33. Possible end products include engineering plastics such as poly(ethylene naphthalate) for use in photographic film and video tape, and heat-resistant polymers such as Kapton. The chemistry of deriving aromatic monomers from coal tar is also considered.

**Liquid Phase Methanol Attractive for Dispatchable Energy Storage**

The Liquid Phase Methanol (LPMEOH) process has been developed for use with Gasification Combined Cycle (GCC) powerplants as reviewed on page 4-26. Methanol is produced from coal-derived synthesis gas off-peak, and is withdrawn from storage and fired on-peak. The economics and emissions performance of a dispatchable GCC energy storage plant incorporating the LPMEOH process are discussed.

**Air-Blown Versus Oxygen-Blown PRENFLO Gasifiers Compared**

A comparison of air-blown and oxygen-blown gasification for PRENFLO gasifiers has led to the conclusion that the air-blown GCC concept may give acceptable efficiency for high-quality coals. However, the oxygen-blown GCC concept would seem to provide greater fuel flexibility, especially for fuels such as lignites, subbituminous coals and biomass. Details are given on page 4-31.

**CRE Gasifier Developed for Topping Cycle**

An air-blown partial gasification component for the topping cycle is being developed at the United Kingdom's Coal Research Establishment (CRE). As is reported on page 4-35, the CRE gasifier can achieve the performance criteria required for the topping cycle with a range of United Kingdom coals. The CRE gasifier is considered ready for scaleup and demonstration.
Puertollano IGCC Project to be Operational in 1996

The status of the Puertollano integrated coal gasification combined cycle powerplant in Central Spain is discussed on page 4-38. The first portion of the plant to be commissioned will be the unit burning natural gas, in the second quarter of 1996. The coal gasification unit should be commissioned at the end of 1996.

KoBra Project Using HTW Gasifier Scheduled for Commissioning in 1996

The High-Temperature Winkler (HTW) fluidized-bed coal gasification process is being used for the KoBra project, a combined cycle powerplant with integrated HTW brown coal gasification, near Cologne, Germany. The plant, which is expected to have a gross electrical output of 367 megawatts, is scheduled for commissioning in August 1996. See page 4-40 for details.

Buggenum IGCC Plant Ready for Demonstration

A 250-megawatt integrated coal gasification combined cycle powerplant has been constructed in Buggenum, The Netherlands, and was expected to begin operations by the end of 1993. Purposes of the project are to demonstrate IGCC as a viable option for electric power generation on a commercial scale, and to gain experience with the IGCC technology. An article begins on page 4-42.

Environmental Impacts at Wabash River Gasification Project Addressed

The Wabash River Coal Gasification Repowering Project is constructing a coal Gasification Combined Cycle (GCC) powerplant, as discussed on page 4-46. The expected environmental impacts of the plant are considered, including air emissions, wastewater, solid wastes and byproducts. Repowering with GCC technology is expected to have a positive environmental impact as compared with the existing technology.

Record United States Coal Production Forecast for 1994

The National Coal Association predicted in January that coal production in 1994 will increase nearly 8 percent from 1993 levels to 1,033 million tons, a new record. As reported on page 4-53, the utility sector accounts for 89 percent of the coal consumed in the United States and just over 80 percent of total United States coal production.

DOE Contractors Report Progress in Natural Gas Conversion

Work on the catalytic conversion of methane and other components of natural gas to various products is reported on page 5-1. Research areas include catalysts in packed-bed and membrane reactors, use of promoted oxide catalysts, development of relatively simple synthetic catalysts based on complex natural catalysts, and use of ceramic membranes in catalytic systems.

Forty Trillion Cubic Feet of Natural Gas Identified in Hydrates on Alaskan North Slope

The United States Geological Survey is assessing the production characteristics and economic potential of continental gas hydrates, particularly in Northern Alaska. As reported on page 5-5, an estimated 40 trillion cubic feet of natural gas trapped as gas hydrates has been discovered. This is about twice the volume of conventional natural gas in the Prudhoe Bay field.
IGT HIGHLIGHTS RESEARCH EFFORTS IN NATURAL GAS AND COAL CONVERSION

The Institute of Gas Technology (IGT), in its 1993 Annual Report, has described progress in energy and environmental research and development work it has been conducting.

Environment

Site remediation is an important component of IGT's environmental research. During fiscal year 1993, the Institute field-tested MGP-REM, an integrated chemical/biological process for the treatment of organic contaminants at former Manufactured Gas Plant (MGP) sites. One test used the technology in the land-farming mode; another test evaluated it in the slurry phase. Results to date indicate that MGP-REM is a reliable and predictable process. Researchers are now conducting bench-scale studies to develop treatment strategies and operating protocols for in situ applications.

In other environmental work, IGT developed improved cultures to remove organic sulfur from Illinois coal. Researchers also successfully biodesulfurized coal-derived products, including liquid products from IGT's MILDGAS mild coal-gasification process. These tests used freeze-fried biocatalysts, which allow cells to be produced in one location, stored indefinitely, then shipped at reduced weight, volume, and cost to another location for use. A feasibility study for using algae to convert flue-gas CO₂ to hydrocarbon fuels was also funded.

Energy

IGT's Molten Carbonate Fuel-Cell (MCFC) technology continued to come closer to commercialization in fiscal year 1993. As the year ended, IGT signed an important licensing agreement with The Netherlands Energy Research Foundation (ECN) that gives the company exclusive rights to manufacture and sell MCFCs in Western Europe. IGT's majority-owned subsidiary M-C Power Corporation has the rights in the United States and Eastern Europe. As part of the agreement, IGT and ECN will exchange technical information aimed at improving fuel-cell performance and endurance.

Improved performance and endurance are also the goals of a subcontract IGT has from M-C Power. Both M-C Power and IGT demonstrated the engineering viability of IGT's IMHEX technology this past year by operating, respectively, full area and subscale stacks, the latter for 7,000 hours. IGT is now working to develop superior components. Two areas being investigated are the reformulation of the porous electrode and the use of different carbonate electrolyte compositions. For another M-C Power project, IGT is testing the performance and endurance of a reformer that converts natural gas and steam into an MCFC fuel gas.

IGT's 7,000-hour stack test was a major step in the development of its IMHEX technology. The original goal was 4,000 hours, but good and steady performance led researchers to operate the 2.5-kilowatt stack longer to obtain more endurance data. Analysis of the operational data and chemical and physical analyses of the cell components are providing valuable information for extending operation to the 40,000-hour level.

In coal gasification work, IGT reported that the world's first commercial-size U-GAS gasifier is being built at Shanghai Coking and Chemical Plant General's WuJin plant. The 800-ton per day plant will produce more than 100 million cubic feet of a low-BTU fuel gas for firing coke ovens, thereby releasing the coke-oven gas for use as town gas. The first of eight gasifiers is scheduled to be in operation by mid-1994.

The Institute licensed its RENUGAS biomass gasification technology to the Finnish company Enviropower Inc. and the Hawaiian-based Pacific International Center for High Technology Research. The latter will demonstrate RENUGAS with sugarcane bagasse in a 100-ton per day plant being built at the Hawaiian Commercial and Sugar Company. The Westinghouse/IGT team will also test a hot-gas cleanup system. The system, including a tar cracker and candle filter, is being added to IGT's 10-ton per day RENUGAS test facility at the EDC. Once testing is completed, researchers will subject the cracker and filter to longer-term testing on a slipstream at the Hawaiian RENUGAS facility. The test data will be used to design and construct a system to clean up gas from the plant for use by a turbine to produce electricity.
IGT’s other gasification research included work on a 24-ton per day process development unit for IGT’s MILDGAS process. In two related projects, IGT is studying the upgrading of mild gasification solids and liquids to value-added industrial products. Both projects are generating the data needed to ensure the marketability and profitability of mild gasification coproducts.

Research is also being conducted on natural gas. Researchers successfully field-tested a membrane separator unit that removes CO$_2$ from subquality gas. Additional tests with a membrane modified by W.R. Grace are being arranged at a well with a higher H$_2$S concentration and flow rate. IGT also started a project to evaluate the potential of rotating gas-liquid contactors for gas processing. Researchers are expanding the current database, especially as it relates to environments typical of those found in gas processing plants, and are addressing operational and reliability concerns.

IGT also continued a project aimed at reducing the cost of removing acid gas and trace impurities from subquality natural gas through the use of a new solvent, N-Formyl Morpholine (NFM). Tests have shown that NFM does not absorb as much methane, ethane, propane, and butane as does a commercially available physical solvent. In another program, biotechnologists demonstrated the production of stereospecific propylene oxide in a novel two-stage bioreactor using a biocatalyst generated on methane.

In other work, IGT’s Design and Engineering Group completed the design of a 3-ton per day bench-scale entrained-bed slagging gasification test facility for the Institute of Advanced Engineering in Korea. IGT started a contract to fabricate and deliver a high-pressure, high-temperature thermobalance reactor system. For Bharat Heavy Electricals Limited of India, IGT and the Pittsburgh Energy Technology Center (PETC) are conducting a design review of a fluidized-bed gasification retrofit for a combined-cycle power station. PETC also sponsored research into the use of hydrogen sulfide to convert methane to gasoline-range hydrocarbons.

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SYNTHETIC FUELS REPORT, MARCH 1994
The United States Department of Energy (DOE) released The Domestic Natural Gas and Oil Initiative in December. The Initiative emphasizes developing natural gas reserves and environmental protection, with little mention of synthetic fuels. The Administration does plan to explore the development of the conventional oil and gas potential of the Naval Oil Shale Reserves.

Two key goals of the Initiative are enhancing the efficiency and competitiveness of United States industry and reducing the trend toward higher imports.

Three major strategic activities are included in the Initiative.

Strategic Activity I--Increase domestic natural gas and oil production and environmental protection by advancing and disseminating new exploration, production, and refining technologies.

Strategic Activity II--Stimulate markets for natural gas and natural-gas-derived products, including their use as substitutes for imported oil where feasible.

Strategic Activity III--Ensure cost-effective environmental protection by streamlining and improving government communication, decision making, and regulation.

The Initiative will also reexamine the costs and benefits of increased oil imports.

Strategic Activity I

This strategic activity is composed of two major actions. The goal of Action 1 is to promote the advancement of natural gas and oil technologies. DOE will promote technology through the following actions:

- Conducting research and development specifically targeting the needs of smaller producers.

- Participating in a United States Treasury Department review of tax provisions related to certain advanced technologies and marginal producers.

- Directing customer-oriented technology transfer efforts.

- Developing a strategy for expanding natural gas markets and technologies. DOE will direct the development of several advanced technologies, including computational analysis of geologic or geophysical data to improve drilling success rates, rock drilling systems for natural gas, advanced oil recovery technologies, and analyses of geologic basins to recover bypassed oil.

The goal of Action 2 is to improve environmental technologies and practices. DOE will advance technologies that serve the dual needs of environmental protection and cost-effective regulatory compliance.

DOE will conduct an environmental technology development and demonstration program to enable the domestic natural gas and oil industry to comply more cost-effectively with environmental regulatory requirements. A key aspect of this effort will be coordination with the United States Environmental Protection Agency, the Department of the Interior (DOI), and other stakeholders. Additionally, DOE will work to develop coordinating mechanisms with non-profit organizations whose efforts are focused on advancing environmental technologies.

Two specific environmental protection areas will also be studied with the intention of developing appropriate policies and actions for DOE's role in the research and development of oil spill cleanup and used oil recycling.

Strategic Activity II

This strategic activity consists of three major actions. The goal of Action 3 is to improve the natural gas infrastructure. This action addresses weaknesses in the present infrastructure, including the physical capabilities for gathering, transporting, storing, and distributing natural gas, and the capabilities for producing accurate, timely information on natural gas supply and demand.

To help improve the physical infrastructure, DOE will work with the Federal Energy Regulatory Commission (FERC) to remove barriers to environmentally sound construction of additional pipeline and storage
facilities. DOE will encourage increased access to existing facilities and will accelerate the development and use of advanced technologies in natural gas storage and distribution.

DOE will also support the industry's efforts to improve real-time capabilities for monitoring and modeling natural gas availability and flows, and to match natural gas storage to end-user requirements. Such efforts will be especially important in enabling greater use of natural gas in electric power generation.

DOE, the FERC, and other interested stakeholders will undertake further discussions of the permitting and regulation of the construction of natural gas pipelines.

The goal of Action 4 is to support natural gas regulatory reform and a "contract portfolio" approach. This action will focus on improving access to natural gas distribution facilities; boosting the use of natural gas for transportation; and encouraging the removal of subsidies that work against energy efficiency goals, cost-cutting by distributors, and efficient pricing for electricity and natural gas.

DOE will also work to educate affected stakeholders on new contract approaches that could lead to improved natural gas availability and market performance.

The goal of Action 5 is to provide information services. DOE will improve its ability to develop, collect, and disseminate information on natural gas deliverability and storage, primarily by enhancing the capabilities of the Energy Information Administration and by developing an Energy and Resources Mapping and Information System.

Strategic Activity III

The objective of this activity is to improve government communication and decision making. Four specific actions are included.

The goal of Action 6 is to simplify regulations without compromising environmental protection. Federal regulatory agencies and departments will streamline and simplify multi-jurisdictional, multi-layer, and overly complex processes that increase compliance costs, while protecting the environment.

The goal of Action 7 is to evaluate production from federal lands. Various agencies and departments will coordinate to ensure that national energy strategies in leasing decisions related to federal lands, and alternative policies to generate greater leasing interest in mature and deepwater areas of the Western and Central Gulf of Mexico are appropriately considered. In addition, DOE will work with Congress and other key agencies to prepare and implement a plan for production of the Naval Oil Shale Reserves.

To develop this plan, DOE will characterize the production potential of the Reserves. The first phase of the program, begun in January 1993, consists of:

- Reprocessing seismic data that are available in the DOE archive
- Acquiring additional, commercially available seismic data
- Producing an assessment of the natural gas and oil potential of Naval Oil Shale Reserve Nos. 1, 2, and 3.

DOE will also work with the DOI and the Office of Management and Budget to conduct economic analyses and to develop a plan for the optimal development of these reserves in an environmentally responsible manner. Assessment of Naval Oil Shale Reserve No. 3 was expected to be completed in January 1994. Assessment of Nos. 1 and 2, is expected to be completed in June 1994.

The goal of Action 8 is to work with states and Native American tribes. Various agencies and departments will work more closely and cooperatively with states and Native American tribes on natural gas and oil supply issues.

The goal of Action 9 is to address West Coast production constraints. DOE will work with the Justice Department, DOI, and the California Public Utilities Commission to ensure access to Central California oil pipelines. The economic, social, and environmental benefits and costs of exporting Alaskan North Slope crude oil will also be examined.

Oil Imports

The National Economic Council and the National Security Council will coordinate an interagency team
headed by DOE to assess the near- and long-term economic, environmental, and security implications of rising United States dependence on oil imports and the role of the federal government in addressing the situation.

The team will also review policy options to reduce oil import vulnerabilities. The study will link the oil imports issue with policy measures being considered to promote domestic supply, energy efficiency, and pollution reduction. And new approaches will be explored that build on already successful energy security strategies, such as maintaining the Strategic Petroleum Reserve and effective multi-lateral cooperation.

The study will be completed in December 1994.

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NATIONAL RESEARCH COUNCIL MAKES RECOMMENDATIONS FOR DOE FOSSIL ENERGY RESEARCH

A National Research Council (NRC) study was requested by the United States Department of Energy (DOE) to examine future needs and priorities in advanced exploratory research related to the following topics:

- Novel and promising areas of research related to oil, gas, shale, and tar sands

- Scientific questions that cut across the full spectrum of fossil fuels

- Currently supported crosscutting research areas that might be broadened or refocused

- Reservoir access and drilling technology

- Composition and physical-chemical and thermodynamic properties of heavy hydrocarbons from oil, shale, and coal-derived liquids

The Committee on Applied Research Needs Related to Extraction and Processing of Oil and Gas was also charged with reviewing current, related DOE programs that are pursued in the Office of Fossil Energy.

The committee formulated the following six assertions that justify DOE’s support of Research, Development, and Demonstration (RD&D) related to oil and gas. These assertions establish the groundwork for priority setting for advanced exploratory research.

- Transportation, power generation, and heating in the United States will rely heavily on liquid hydrocarbon fuels and natural gas for the foreseeable future.

- There are significant economic, security, and employment benefits to making use of domestic resources to help meet United States liquid fuel and gas needs.

- Advanced technology is essential to cost-effective domestic oil and gas operations. Not only can it lower the cost of domestically produced crude oil, petroleum products, and natural gas, but it can also expand the domestic resource base.

- Of particular importance is the prospect that improved technology for enhanced oil recovery could significantly expand the production of domestic oil.

- Research and development to improve refining is important to maintaining low prices for petroleum products as poorer-quality crudes (and eventually feeds manufactured from shale and coal) find their way to markets, and as changes in fuel composition are mandated by environmental and health-related regulations.

- Funding of upstream and downstream oil and gas RD&D by the DOE is of greater potential importance today because industry-sponsored RD&D has been significantly reduced in recent years and refocused to emphasize the short term.

The Council report deals only with the DOE’s advanced exploratory research portfolio and does not address the overall balance of the DOE’s efforts across the entire oil and gas RD&D spectrum.

Tables 1 and 2 give the Council’s recommended priorities to help the DOE balance its advanced ex-
### Table 1: Recommended Priorities for DOE Funding of Major Upstream Research Topics Under Three Budget Scenarios

<table>
<thead>
<tr>
<th>Major Research Topic</th>
<th>Increased Budget</th>
<th>Current Budget</th>
<th>Decreased Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid-Rock Interactions</td>
<td>H</td>
<td>M</td>
<td>O</td>
</tr>
<tr>
<td>Geochemistry</td>
<td>H</td>
<td>H</td>
<td>M</td>
</tr>
<tr>
<td>Seismic Technologies</td>
<td>H</td>
<td>M</td>
<td>O</td>
</tr>
<tr>
<td>Logging</td>
<td>H</td>
<td>H</td>
<td>M/L</td>
</tr>
<tr>
<td>Reservoir Characterization</td>
<td>H</td>
<td>H</td>
<td>H</td>
</tr>
<tr>
<td>Reservoir Simulation</td>
<td>H</td>
<td>M</td>
<td>L</td>
</tr>
<tr>
<td>Drilling</td>
<td>H</td>
<td>H</td>
<td>O</td>
</tr>
<tr>
<td>Mobility Control</td>
<td>H</td>
<td>H</td>
<td>M/L</td>
</tr>
<tr>
<td>Chemical Recovery</td>
<td>H</td>
<td>M</td>
<td>O</td>
</tr>
<tr>
<td>Miscible Recovery</td>
<td>H</td>
<td>M</td>
<td>O</td>
</tr>
<tr>
<td>Microbial Recovery</td>
<td>L</td>
<td>O</td>
<td>O</td>
</tr>
<tr>
<td>Formation Damage/Stimulation</td>
<td>M</td>
<td>L</td>
<td>O</td>
</tr>
<tr>
<td>Profile Control</td>
<td>H</td>
<td>M</td>
<td>O</td>
</tr>
<tr>
<td>Fracturing</td>
<td>H</td>
<td>L</td>
<td>O</td>
</tr>
</tbody>
</table>

**Note:** "Increased funding" refers to a level for the DOE's entire advanced exploratory research program related to oil and gas that is two or more times greater than FY1993 funding, and "decreased funding" corresponds to a level approximately half that of FY1993 funding. "H," "M" and "L" indicate high, medium and low priorities, respectively and zero is a recommendation to not fund.

Three factors were considered before the recommended priority level for each major research category was determined:

- Potential for valuable scientific or technological advances
- Potential impact of the application of successful results
- Importance of DOE's participation

Table 1 shows the committee's recommended relative priorities for funding major research categories in the upstream arena, for three conceivable budget levels for the DOE's entire advanced exploratory research program related to oil and gas.

Table 2 presents the committee's recommended relative priorities for DOE funding of major downstream research topics and is to be interpreted in the same manner as Table 1.

It is important for the DOE to support a significant level of high-quality advanced exploratory research in both downstream and upstream research activities, according to the NRC. For the three funding levels of Tables 1 and 2, program balance should be as recommended in Table 3.

The Council says the DOE program in advanced exploratory research related to oil and gas is very important. The DOE has a special responsibility to protect the national interest through long-range research, and the committee strongly recommends that DOE consider a much higher budget for this program.

**DOE's Role in Advanced Exploratory Research**

It is the Committee's strong belief that the economic pressures that are driving the oil and gas industry...
TABLE 2

RECOMMENDED PRIORITIES FOR DOE FUNDING OF MAJOR DOWNSTREAM RESEARCH TOPICS UNDER THREE BUDGET SCENARIOS

<table>
<thead>
<tr>
<th>Major Research Topic</th>
<th>Increased Budget</th>
<th>Current Budget</th>
<th>Decreased Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermodynamics and composition of heavy fractions</td>
<td>H</td>
<td>H</td>
<td>H</td>
</tr>
<tr>
<td>Kinetics and reaction pathways for heavy petroleum hydrocarbons</td>
<td>H</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>Kinetics and reaction pathways for shale oil and shale kerogen</td>
<td>H</td>
<td>H</td>
<td>H</td>
</tr>
<tr>
<td>Kinetics and reaction pathways for coal liquids</td>
<td>H</td>
<td>H</td>
<td>M</td>
</tr>
<tr>
<td>Kinetics and reaction pathways for synthesis gas conversion</td>
<td>H</td>
<td>M</td>
<td>L</td>
</tr>
<tr>
<td>Conversion of methane to liquid fuels</td>
<td>L</td>
<td>L</td>
<td>0</td>
</tr>
<tr>
<td>Membrane separations</td>
<td>H</td>
<td>M</td>
<td>L</td>
</tr>
</tbody>
</table>

NOTE: See Table 1

TABLE 3

RECOMMENDED BALANCE FOR DOE FUNDING OF UPSTREAM AND DOWNSTREAM ADVANCED EXPLORATORY RESEARCH

<table>
<thead>
<tr>
<th>Percent for Upstream Research</th>
<th>60</th>
<th>40</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percent for Downstream Research</td>
<td>70</td>
<td>30</td>
</tr>
</tbody>
</table>

Projects in this area are focused generally on the upgrading of heavy hydrocarbons; the development of new processes, agents, and technologies; and improving process efficiencies and environmental acceptability. Included are projects oriented toward surface extraction processes, such as for Western tar sands, and the retorting of oil shale. Most, if not all, of this work falls outside the definition of advanced exploratory research, and the budget according to NRC should be reduced. Other projects include characterization of component compounds of heavy oils and identification of their reactions; the development in partnership with industry of new and improved...
processes (largely applicable to tar sands) for upgrading heavy oils; development of a methodology for determining threshold conditions and mitigating fouling (coking) of heat exchangers and furnace tubes when processing residuum and other heavy oils; and reactive flow simulations of heavy-oil upgrading.

In addition to these programs, major refiners have large R&D programs aimed at developing new and improved catalysts and processes for converting heavy oils and residuum to transportation fuels. One research program on extraction of oil from tar sands is being carried out under the DOE program. The Office of Fossil Energy also supports a significant amount of related long-term R&D related to bioprocessing and liquefaction of coal; this R&D focuses on novel approaches to liquefaction, the fundamental chemistry of coal liquefaction, and advanced catalysis, but to some extent this work contributes to the total DOE effort in advanced exploratory research related to oil.

NRC recommends studies such as those that would lead to a better understanding of fundamental process steps and the interactions of hydrogen, steam, hydrogen donors, and lighter hydrocarbons with primary thermal cracking products in the presence of a catalyst. Research is suggested aimed at developing better catalysts for upgrading primary reaction products from shale retorting, heavy-oil cracking, and coal liquefaction: catalysts that remove heteroatoms at higher velocities and without excess formation of light gases, or that convert multi- and single-ring aromatics and naphthenes to environmentally superior compounds.

Conversion of Methane to Liquids

The DOE fiscal year 1994 Strategic Plan includes a goal for achieving by year 2000 the demonstration of "...direct conversion of light hydrocarbons (particularly natural gas) to transportation fuels competitive with $25 to $30 per barrel crude (1991 dollars). However, because major oil companies are investing significant sums on research into such processes, the Committee feels it is difficult to justify a process-oriented DOE program. In fact, says the Committee, proven commercial processes are available for converting natural gas to methanol, gasoline, diesel fuel, and chemicals, but they are not economical in the United States at the oil and gas prices likely to prevail in the coming 2 or 3 decades.

Shale Oil Production and Upgrading

According to NRC, utilization of the large oil shale reserves in the United States is not economical at present because of the large investment required and the complex technology for recovering oil from this source. A 1990 NRC study identified a large number of potential cost reductions in retorting and upgrading and recommended active research programs in the following areas:

- Material handling and solids flow
- Reaction kinetics of kerogen retorting
- Process application chemistry
- Modified in situ processes
- Mining research

A shale oil retorting pilot plant program had a fiscal year 1993 budget from DOE of $4 million, but these funds were eliminated from the fiscal year 1994 budget. The Committee offered no support for continuation of this work.

The NRC notes that upgraded shale oil can produce high-quality transportation fuels that can meet environmental requirements for low content of aromatics and sulfur. The potential still exists for cost reductions in producing shale oil. For example, potential savings would result from developing a retort process that would produce a lighter, lower-molecular-weight oil that could be piped to existing refineries before being upgraded. Possible ways to reduce the molecular weight of shale oil are:

- To use a catalytic material as a portion or all of the heat transport agent, as in catalytic cracking in a low-pressure hydrogen atmosphere
- To develop a very-short-contact-time retort with possible heavy-oil recycle

Extraction of Oil From Tar Sands

A cost study in the 1990 NRC report found that, based on current technology, the cost of oil produced from any alternative source would be substantially higher than the current cost of petroleum; however, of the alternative sources, tar sands oil would be the least costly. The 1990 study recommended DOE research in the following areas:
- Characteristics of nitrogen compounds, to improve the upgrading of low-API-gravity, high-nitrogen bitumen
- Solid-liquid interactions to improve removal of fine solids
- Dissolution mass transfer effects to optimize the extraction and separation operation
- Improved extraction techniques, to improve bitumen recovery
- Upgrading of feeds containing solids (need pilot plant demonstrations) due to solids-handling requirements for disposal
- Environmental studies, especially for solid waste disposal
- Improved techniques for efficient and selective mining of the richest ores

In its new report the NRC makes no new recommendations.

Coal Liquefaction

The 1990 NRC study found that, although liquid fuels produced from coal were more expensive than those obtained from petroleum with current technology, advanced technology showed promise for reducing costs significantly. Recommended approaches to reducing this cost included:
- A vigorous basic and exploratory research program
- A pilot plant program capable of supplying the information needed for commercial-scale designs
- Continuing systems studies aimed at optimization
- A new thrust aimed at integration of hydrogen production from both biomass and coal
- A high level of industrial involvement

Also recommended was a medium level of funding for coal-oil processing.

Based on the broad usefulness of the research and the large incentive to utilize coal, the objectives of most of the DOE's current long-term program on coal liquefaction appear to be well defined and useful, according to NRC. Research efforts that concentrate on basic chemistry, catalysis, and new process concepts aimed at reducing the cost of coal liquefaction and producing products that are environmentally acceptable can have crosscutting value to the advanced exploratory research program for oil.

For indirect liquefaction of coal, NRC suggests research into processes and new catalysts with superior yields of high-octane alkylate.

####

SYNTHETIC FUELS REPORT, MARCH 1994
BATTENEL FORECASTS SLIGHT INCREASE IN OVERALL R&D SPENDING FOR 1994

Expenditures for research and development (R&D) in 1994 in the United States are expected to reach $164.5 billion, according to an annual Battelle forecast.

This represents an increase of $3.8 billion, 2.3 percent, over the $160.7 billion the National Science Foundation estimates actually was spent for R&D in 1993.

Because about 2 percent of the R&D increase will be absorbed by inflation, Battelle forecasts a negligible increase in real total R&D expenditures. This is considerably less than the 10-year average real increase of 2.5 percent since 1983.

Sources of Funds

Industrial funding for R&D will account for 51.6 percent of the total. Industrial support is forecast to be $83.6 billion, up 1.6 percent from 1993.

Battelle sees an increase of 2.6 percent in federal support for R&D, with funding expected to be $69.8 billion. This is 42.2 percent of the total expenditures for 1994, but it represents a smaller increase than originally proposed in President Clinton's first budget.

Funding by academic institutions is expected to be $6.4 billion, 3.9 percent of the total. Other non-profit organizations will provide nearly $3.5 billion (2.1 percent).

Performers of Research

According to the Battelle report, industry will continue to perform most R&D. In 1994, performance by industry is expected to rise to $114.8 billion, slightly less than 70 percent of all research. This compares with $16.8 billion (10.2 percent) by federal government laboratories, $26.7 billion (16.2 percent) by academic institutions, and nearly $6.2 billion (3.7 percent) by non-profit organizations.

Federal funding supports research in all four sectors. About 46 percent of the federal R&D dollars are used by industry. Federal laboratories and colleges and universities receive about 24 percent each, and the remainder, about 5 percent, goes to other non-profit organizations.

Government Support

Defense, energy, space, and health and human services dominate the federal R&D scene and account for 82.6 percent of the total proposed federal R&D funding for 1994, only slightly less than in 1993. The make-up of this funding will not change significantly in 1994. Statistics on some federal R&D expenditures for 1989 and 1991, and projections for 1994, are presented in Table 1.

The emphasis on federal R&D funding as a means of supporting domestic economic growth is evidenced in three initiatives that are expected to continue.

- Congressional action on some of the so-called "big science" programs--including the superconducting supercollider and the space station--came under close scrutiny.

- Efforts are being directed toward reshaping the basic research missions of the National Science Foundation, the National Institute of Standards and Technology, and the United States Department of Energy in an effort to direct resources toward more immediate applied research programs.

- Efforts at developing collaborations between industry and the federal laboratories are being pursued more vigorously.

Industrial Support

Industrial support of research will continue to grow in areas related to electronics, communications, sensors, transportation, advanced machinery, and in fields directly influenced by the need for more energy-efficient products and processes, and environmental protection.

The pattern of industrial support for R&D shows departures from a relatively strong role in basic research, with this having been relegated to the universities on an increasing scale. Furthermore, structural change within industrial laboratories is opening the
door for a greater use of subcontracted R&D, and
greater use is being made of off-shore R&D facilities.
This is offset, in part, by an increasing amount of R&D
performed by United States entities for foreign-based
corporations.

In spite of significant changes, near-term industrial
plans indicate that the slowdown in R&D growth may
be stabilizing. Downsizing in all aspects of operations
will have an adverse impact on R&D personnel levels.
However, Battelle expects these moves to be offset by
an increased interest in collaborative research
programs. Furthermore, industrial postures in R&D
spending will be influenced by the anticipation of a
stronger federal government role in encouraging
public/private partnerships, in promoting permanent
R&D tax credits, and in enhancing the roles of the
federal laboratories.

State governments also continue to expand their roles
and activities in support of a broad range of activities
directed toward technology-based economic develop-
ment and job expansions.

**Long-Term Outlook**

The R&D growth rate has been slowing and is ex-
pected to continue to decline in real terms, although
no significant decrease in real dollar support is ex-
pected.

Industrial support will continue to be affected by con-
flicting and complex factors, for example, major
changes in the traditional defense industries are forc-
ing realignments within the industry.

The trade imbalance and efforts to correct it, as well as
efforts to expand markets in response to shifts in
government priorities, could spur expanded R&D. In
addition, the internationalization of markets—as
promoted through expanding trade agreements—will
influence R&D expenditures as United States-based
companies attempt to accommodate the different
regulatory postures and consumer behaviors in other
parts of the world.

The tenor of the federal budget for 1994 and the pro-
technology attitude of the present administration also
give Battelle reason for cautious optimism regarding
R&D growth and accountability in the near future.

###

**UNITED STATES DEPENDENCE ON OIL IMPORTS CONTINUES TO CLIMB**

An Energy Information Administration (EIA) report
released in January, the *Annual Energy Outlook
1994—With Projections to 2010*, indicates that
American dependency on foreign oil is expected to rise
rapidly. The report shows net oil imports rising to
60 percent of consumption by 2010, up from 38 percent
in 1992. Petroleum consumption climbs to over
21 million barrels per day in 2010, from 17 million bar-
rels per day in 1992. Imports fill the gap between con-
sumption and lower domestic production as United
States oil resources are depleted.

The report projects that people will continue to drive
more and that new car efficiency gains will not be as
rapid as in the 1980s. As the population grows and ur-
ban driving and congestion increase, the gap between
United States Environmental Protection Agency rated

---

**TABLE 1**

**FEDERAL R&D EXPENDITURES BY AGENCY**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Department of Defense</td>
<td>58.5%</td>
<td>59.6%</td>
<td>67.8%</td>
</tr>
<tr>
<td>Health and Human Services</td>
<td>14.8</td>
<td>14.0</td>
<td>11.9</td>
</tr>
<tr>
<td>(includes Nat’l Institutes of Health)</td>
<td>9.3</td>
<td>9.8</td>
<td>6.2</td>
</tr>
<tr>
<td>NASA</td>
<td>3.9</td>
<td>4.4</td>
<td>3.5</td>
</tr>
</tbody>
</table>
miles per gallon and actual on-the-road miles per gallon is expected to widen.


Highlights from the report are summarized in the following.

Total primary energy consumption grows to 105 quadrillion BTU (including renewable fuels) by 2010, a 23 percent increase from 1992. Energy conservation and technological advances moderate the expected demand growth.

Energy intensity (thousand BTU consumed per dollar of gross domestic product) is expected to continue to decline. A somewhat lower rate of decline (1 percent a year through 2010, compared with 1.5 percent between 1970 and 1990) is partly due to lower efficiency gains in the automotive sector.


Greater coal-fired electricity generation, industrial consumption, and exports are expected to stimulate coal production through 2010. Coal production is expected to increase from its 1992 level of nearly 1 billion short tons to 1.2 billion short tons in 2010.

Estimated carbon emissions from fossil fuel combustion increase from 1.3 billion metric tons in 1990 to 1.6 billion metric tons in 2010, assuming no change in current regulations. Coal remains the largest source of carbon emissions from electricity generation despite the growing use of natural gas and renewables.

###

WORLD ENERGY COUNCIL FORESEES BIG INCREASES IN ENERGY DEMAND BY 2020

A World Energy Council (WEC) Commission has conducted a study on world energy consumption, considering economic, technical, environmental, social and institutional factors. The study has been published in book form, Energy for Tomorrow's World.

The study concentrates, from a global aspect, on those key issues which will shape energy provision and its use in the future such as population growth, economic and social development, access to sufficient energy for the developing world, local and regional environmental impact, possible global climate change, efficiency of energy supply and use, financial and institutional issues, technological innovation and dissemination, and single energy issues.

Global Perspectives

The Commission developed four global energy cases, each representing different assumptions in terms of economic development, energy efficiencies, technology transfer and the financing of development around the world. These cases were developed to illustrate future possibilities. They are not predictions. In all four cases, covering a wide range of possibilities, major improvements in energy efficiency compared to historic performance are required—though to differing degrees within the various economic groupings of countries. The main horizon year adopted is 2020. The key characteristics of the four cases are given in Table 1.

The Reference Case (B) represents an updated version of that developed by the WEC in 1989. The other three are variants to illustrate sensitivities to changes in the basic assumptions.

The Ecologically Driven Case (C) is based on the premise that annual carbon dioxide emissions are to be broadly stabilized by 2020 at their 1990 levels.

In all four cases the critically important projection of population growth is assumed to be the same and is

SYNTHETIC FUELS REPORT, MARCH 1994
TABLE 1

MAIN CHARACTERISTICS OF THE FOUR WEC ENERGY CASES

<table>
<thead>
<tr>
<th>Case</th>
<th>A</th>
<th>B&lt;sub&gt;1&lt;/sub&gt;</th>
<th>B</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Name</td>
<td>High</td>
<td>Modified High</td>
<td>Reference</td>
<td>Ecologically Driven</td>
</tr>
<tr>
<td>Economic Growth % pa</td>
<td>High</td>
<td>High</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>OECD</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
</tr>
<tr>
<td>CEE/CIS</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
<td>2.4</td>
</tr>
<tr>
<td>Devel. Countries</td>
<td>5.6</td>
<td>4.6</td>
<td>4.6</td>
<td>4.6</td>
</tr>
<tr>
<td>World</td>
<td>3.8</td>
<td>3.3</td>
<td>3.3</td>
<td>3.3</td>
</tr>
<tr>
<td>Growth per Capita</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>OECD</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>CEE/CIS</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>Devel. Countries</td>
<td>Very High</td>
<td>High</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td>Asia</td>
<td>Moderate</td>
<td>Low</td>
<td>Low</td>
<td>Low</td>
</tr>
<tr>
<td>Sub-Saharan Africa</td>
<td>High</td>
<td>Moderate</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>Most Others</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Intensity Reduction % pa</td>
<td>High</td>
<td>Moderate</td>
<td>High</td>
<td>Very High</td>
</tr>
<tr>
<td>OECD</td>
<td>-1.8</td>
<td>-1.9</td>
<td>-1.9</td>
<td>-2.8</td>
</tr>
<tr>
<td>CEE/CIS</td>
<td>-1.7</td>
<td>-1.2</td>
<td>-2.1</td>
<td>-2.7</td>
</tr>
<tr>
<td>Devel. Countries</td>
<td>-1.3</td>
<td>-0.8</td>
<td>-1.7</td>
<td>-2.1</td>
</tr>
<tr>
<td>World</td>
<td>-1.6</td>
<td>-1.3</td>
<td>-1.9</td>
<td>-2.4</td>
</tr>
<tr>
<td>Technology Transfer</td>
<td>High</td>
<td>Moderate</td>
<td>High</td>
<td>Very High</td>
</tr>
<tr>
<td>Energy Efficiency Improvement</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>OECD</td>
<td>High</td>
<td>High</td>
<td>High</td>
<td>Very High</td>
</tr>
<tr>
<td>CEE/CIS</td>
<td>Moderate</td>
<td>Moderate</td>
<td>High</td>
<td>Very High</td>
</tr>
<tr>
<td>Devel. Countries</td>
<td>Moderate</td>
<td>High</td>
<td>High</td>
<td>Very High</td>
</tr>
<tr>
<td>Institutional Improvements (World)</td>
<td>High</td>
<td>Moderate</td>
<td>High</td>
<td>Very High</td>
</tr>
<tr>
<td>Possible Total Demand (Gtoe)</td>
<td>Very High</td>
<td>High</td>
<td>Moderate</td>
<td>Low</td>
</tr>
<tr>
<td>(1990 = 8.7 Gtoe)</td>
<td>17.2</td>
<td>16.0</td>
<td>13.4</td>
<td>11.3</td>
</tr>
<tr>
<td>CO₂ Emissions from Fossil Fuel (GtC)</td>
<td>10.6</td>
<td>9.5</td>
<td>7.8</td>
<td>5.8</td>
</tr>
</tbody>
</table>

The WEC states that only in the Organization for Economic Cooperation and Development (OECD) and Central and Eastern Europe/Commonwealth of Independent States (CEE/CIS) is there potential for containing future energy demand (Figure 1). Population increases and economic development in many of the developing countries make it inevitable that they will consume considerably increased amounts of energy for many decades. Even the Ecologically Driven Case C (which assumes a dramatic improvement in developing countries’ energy efficiency far beyond historic experience, and despite static per capita energy consumption in some areas resulting from continuing poverty) projects major increases in energy consumption within these countries.

Conversely, cost-effective energy efficiency measures cannot be implemented indefinitely. It is therefore, likely that the rate of reduction in energy intensities (the amount of energy consumed to yield a unit of Gross Domestic Product (GDP) at constant prices--or more positively the increasing amount of GDP which can be generated from a given amount of energy) will slow after 2020 in both the OECD and CEE/CIS. On the other hand, improved energy efficiency in the...
developing countries will reflect their more efficient use of manpower, capital and natural resources. Much of this may therefore happen after 2020.

The improvement in energy efficiency assumed in the Ecologically Driven Case C—in particular for the CEE/CIS and developing countries—is such that it will require a massive program of technology transfer, financing and commercial implementation of energy-efficient technology if it is to be achieved before 2020. Even with major governmental assistance this may not be possible.

A comparison of possible global energy supply mixes for the four cases in the year 2020 with the corresponding mix for 1990 (Figure 2) shows that fossil fuels continue to dominate the energy mix over the next 3 decades and are likely to do so well beyond this period. The only exception is shown in the Ecologically Driven Case C, which is based on extreme assumptions thought unlikely to be achievable before the horizon year of 2020.

Many of the energy mix elements in the four cases line up against their theoretical maxima on today’s knowledge and capabilities. Two, however, demand special consideration.

The contribution from nuclear power to increasing electricity production is assumed to grow in all cases. This cannot be taken for granted. If nuclear energy does not develop it is likely to be replaced by coal.

New renewable energy sources will play an increasing role in the energy mix in absolute terms. However, with the exception of the Ecologically Driven Case C they will make a modest contribution up to 2020 in relative terms.
Carbon Dioxide Emissions

Carbon dioxide emissions and the greenhouse effect were also considered by WEC. Many references to the relationship between fossil fuel burning and environmental protection relate to the overall context of carbon sources and sinks. The Intergovernmental Panel on Climate Change believes that 1990 source emissions of carbon dioxide totaled 200 gigatons of carbon while sinks worldwide absorbed 194 gigatons of carbon. Fossil fuel burning probably accounted for 5.5 gigatons of carbon emissions in 1990 and traditional fuels for 0.4 gigatons of carbon—totaling some 3 percent of global CO₂ emissions from all sources. The crucial question is whether this 3 percent anthropogenic contribution, and an increase in it, will create global climate change.

From Table 2 it can be seen that the Ecologically Driven Case C is the only one which will have global CO₂ emissions from fuel combustion in 2020 close to their 1990 level. As has been pointed out, stabilization of annual CO₂ emissions was the theoretical requirement for this case. All the other cases show large increases in annual CO₂ emissions. However, none of the cases allows a stabilization of greenhouse gas concentrations in the atmosphere within the next few decades.

The WEC Commission recommends the following approach regarding possible global climate change:

- Recognizing the uncertainties and the need for intensified research to improve scientific understanding in this field.

- The need to raise energy efficiency whenever it can be justified on the basis of cost/benefit analysis and to increase energy conservation.

- The application of rational adaptation measures now, because if the hypotheses
about global climate change are scientifically proven then the world is probably already past the point where it can be avoided.

- If rational abatement and adaptation strategies are to be adopted with the necessary speed and effectiveness then government involvement is required to provide stimulus and leadership. Such government action should allow for the optimal use of market instruments and industry-initiated responses to the potential problem; for example, tradable emission permits; and road user pricing.

Measures must be effective, their implementation cost effective, and they need to have the joint support of governments, energy operatives, and the consumers who will have to pay the costs—in order to reap the benefits of such measures.

Regional Perspectives

The WEC Commission found from regional analyses that the first priority for the majority of the world's population is access to sufficient affordable energy. Some 70 percent of the world's population lives at a per capita energy consumption level one-quarter that of Western Europe, and one-sixth that of the United States. In many cases this inhibits even minimal economic growth (e.g., in certain African countries), and restricts services basic to human needs. In other developing countries (e.g., China) sufficient energy is available to support planned growth but not without potentially serious environmental implications.

The second priority highlighted by the regions is solving local environmental problems, such as deforestation, soil erosion, unplanned and uncontrolled urbanization, unchecked industrial pollution, water scarcity and contamination, and loss of natural habitats for wildlife.

The third priority is the need to increase energy efficiency. Such improvement can only be achieved, however, with considerable investment in old as well as new plants, buildings, processes, appliances and in fuel substitution.

Among other key issues highlighted are the need for:

- Massive investment to expand existing energy systems and technologies. This could total US$30 trillion by 2020. By comparison the world GDP in 1989 was some US$20 trillion.

- Through such investment the transfer or local development of modern energy technology suited to local needs, such as mini-hydro and small-scale solar schemes.

- The provision of education, training and technological support for the development of energy systems and local technological independence.

- Substantial institutional change to facilitate the progressive introduction of market systems, foreign equity participation and the mobilization of local capital markets.

By contrast to the discussions in many industrialized countries, WEC found that the reactions from most regions are that the perceived problem of global climate change is not a high priority, particularly among the developing countries.

The WEC concluded that for the developing countries, then, despite the disparate nature of such a grouping,
the key issues are economic growth, access to adequate commercial energy supplies and the finances needed to achieve these.

For the CEE/CIS countries in transition, the key issues are the modernization and expansion of their existing supply infrastructures, the promotion of the rational use of energy, the transition of market-oriented policies and enterprises, and the introduction of stable legal and fiscal regimes which foster investment and satisfactory investment returns.

For the industrialized countries, the dominating issues are securing greater energy efficiency and continuous improvement to the technologies deployed in their own countries and elsewhere.

The consequences of the huge forecasted increase of global population will be the accelerated consumption of the reserves of fossil fuels, with coal depleting less rapidly than oil and natural gas. The result will be increased reliance on coal and ultimately a shift (probably well into the 21st century) to other fossil resources (such as tar sands, shale oil, synthetic gas, etc.) which can only be developed at higher cost, with the application of improved technologies, but with the risk of increased environmental impact.

The higher cost of fossil fuels and environmental considerations will place increased emphasis on energy efficiency, and should stimulate the development and implementation of the various other energy sources.

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BECHTEL SEES NEED FOR 100 GW OF NEW U.S. GENERATING CAPACITY IN NEXT 10 YEARS

An overview of United States electricity markets through the year 2003 is presented in a paper by J.R. Siegel of Bechtel Power Corporation.

In Figure 1, changes in Gross Domestic Product (GDP), electricity consumption, and energy consumption are plotted, using 1973 as a base year. During this period, electricity consumption grew marginally faster than real GDP, at a rate of 2.6 percent per year, compared to real GDP growth of 2.2 percent per year. Total energy growth, however, has averaged only 0.5 percent per year.

Electricity in 1993 represented about 37 percent of all energy consumed in the United States, up from 26 percent in 1973.

Looking to the future, Bechtel made the following assumptions:

- Real GDP grows at an average of 2.2 percent per year.
- Utilities add new supply to maintain a reliability margin of 15 percent; this assumed margin is below the historical 20 percent benchmark, and reflects the evolving, highly competitive utility environment.
- Supply planning considers the North American Electric Reliability Council regional and subregional data.
- 200 gigawatts (GW) of capacity older than 30 years will receive major overhauls which will maintain the useful lives of these units.
- Retrofit/deratings and early retirements--in part, the result of the Clean Air Act--remove about 10 GW capacity in the 1990s; this 10 GW is offset by about 10 GW of mothballed capacity that is reactivated.

Bechtel's base case forecast is for 2.0 percent per year average increase in peak electric demand, with a range
between 1.5 and 2.5 percent per year. This forecast assumes successful load management and conservation at the same rate experienced over the last 10 years.

Real electricity prices from 1960 to 1993 are plotted in Figure 2. Real electricity prices decreased until 1973. Fuel price increases, rising inflation and interest rates, and supply additions exceeding demand growth between 1973 and 1982 caused real electricity prices to increase. Since 1982, however, real electricity prices have decreased dramatically, the result of lower fuel prices, falling inflation and interest rates, and demand growth exceeding supply additions. Today, despite a doubling in the size of the rate base, pending utility rate cases are at a 20-year low.

Bechtel expects the demand for electricity to roughly match GDP growth due to falling electricity prices, rising end-use gas prices, a healthy manufacturing sector, sustained growth in capital spending in the 1990s, and technical and environmental initiatives which result in electricity substituting for gas and oil at the end use. From 1987 through 1993, electricity demand has exceeded GDP growth by roughly 1 percentage point.

At a 2.0 percent per year average growth rate (assuming 15 percent reserve margin), additional electric generating capacity of 100 GW must be installed and operating by 2003 (Figure 3). At the extremes of 1.5 and 2.5 percent per year, the range of requirements that must be operating by the year 2003 is 70 to 130 GW. Considering lead-times, about 140 GW must be ordered over the next 10 years. Bechtel assumes Non-Utility Generators build about 50 percent of new capacity.

In Bechtel's base case forecast, gas is the fuel of choice in the near term. Coal economics prevail near the end of the period, largely due to forecast increases in gas prices. During the first 5 years, Bechtel forecasts new orders to be nearly two-thirds gas or dual fuel and one-third to be coal or solid fuel. In the second 5 years, orders are predicted to be one-half gas or dual fuel and one-half coal or solid fuel. Alternative energy sources and renewables can be expected to add an important, albeit small, amount of capacity. In arriving at these fuel market shares, the following real fuel price increases were assumed:

- Oil and natural gas, 3 percent per year
- Coal, 1 percent per year

The 1993 starting points are $20 per barrel oil (West Texas Intermediate), $2.80 per million BTU delivered utility gas, and $1.50 per million BTU delivered utility coal.
The technology mix also varies during the forecast period. Technologies Bechtel envisions for coal include pulverized coal, fluidized bed combustion and integrated coal gasification combined cycle. Also to be constructed are waste-to-energy units, and as indicated earlier, the repowering and upgrading of existing facilities. Bechtel Power assumes that new nuclear orders will commence near the end of the decade, if important policy questions are addressed.

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ATTRACTIVE SUBSIDIES ARE AVAILABLE FOR BIOMASS GASIFICATION

The United States Congress has created several tax benefits and subsidies for the production of energy from biomass. Congress enacted biomass energy incentives in 1978 with the creation of excise tax exemptions for alcohol fuels, in 1980 with the enactment of the Internal Revenue Code (IRC) Section 29 non-conventional fuel credit provisions and the IRC S40 alcohol fuel credits, and recently with the addition of favorable biomass energy provisions as part of the Comprehensive National Energy Policy Act of 1992.

G.A. Sanderson and K. Martin, in separate papers presented at the First Biomass Conference of the Americas held in Burlington, Vermont in August, discuss the following specific tax credits, tax benefits and subsidies for biomass energy:

- IRC S29 credit for producing gas from biomass
- IRC S45 credit for producing electricity from biomass
- Incentive payments for electricity produced from biomass
- Excise tax exemptions for alcohol fuels
- IRC S40 alcohol fuels credits
- IRC S179A special deduction for alcohol fuels property
- Accelerated depreciation on related equipment
- Tax-exempt financing

IRC S29 Biomass Gas Credit

In 1980, Congress enacted the Section 29 income tax credit provisions as part of the Crude Oil Windfall Profits Tax Act to promote the production and sale of energy from "non-conventional sources." The two "non-conventional sources" which may qualify today for the S29 credit are gases produced and sold from biomass, and synthetic fuels produced and sold from coal. The S29 credit is available for biomass gasification and coal fuels facilities placed in service by December 31, 1996, pursuant to written contracts signed by December 31, 1995. Facilities which meet these deadlines, and are originally placed in service after December 31, 1992, can qualify for the S29 credit until January 1, 2008.

The S29 credit is based on a barrel-of-oil equivalent, adjusted annually for inflation. The 1992 credit was $5.53 per barrel.

To qualify for the S29 credit, the biomass facility must produce a combustible gas from biomass and sell this gas to an "unrelated" party.

The S29 credit is phased out when oil prices exceed a certain level, which is adjusted annually for inflation. The 1992 credit would have begun to phase out if oil prices had exceeded $43.31 per barrel.

IRC S45 Electricity From Biomass Credit

The Comprehensive National Energy Policy Act of 1992 added an income tax credit under IRC S45 for production of electricity from wind and biomass facilities. Under this new S45, a credit of $0.015 is allowed for each kilowatt-hour of electricity produced from wind or closed-loop biomass facilities if the electricity is sold to an "unrelated" party. Closed-loop biomass is defined as any organic material derived from a plant which is planted for the exclusive purpose of being used to produce electricity. The Congressional Committee Reports state that this credit will not be available for electricity produced from scrap wood and agricultural waste, or from standing timber. The credit is phased out as the national average price of electricity exceeds a threshold price range of $0.08 to $0.11 per kilowatt-hour. Both the $0.015 credit amount and this phase-out range will be adjusted annually for inflation.

Electricity Production Incentive

In addition to the IRC S45 electricity credit, the 1992 Energy Act also added an incentive payment provision entitled "Renewable Energy Production Incentive," for electricity generated and sold from solar, wind, biomass or geothermal energy. This electricity incentive amount is $0.015 per kilowatt-hour, adjusted annually for inflation, and is available to
states, political subdivisions, any corporation or association which is wholly owned (directly or indirectly) by states or political subdivisions, and to non-profit electrical cooperatives. Unlike the IRC 545 credit, the electricity production incentive appears to be available for all forms of biomass, except that burning municipal solid waste and producing energy from certain dry steam geothermal reservoirs will not qualify.

Excise Tax Exemptions for Alcohol Fuels

Several tax incentives exist in the Internal Revenue Code for alcohol fuels. Perhaps the most important alcohol fuels incentive, however, is the exemption of methanol and ethanol fuel blends from excise taxes levied on gasoline, diesel and aviation fuels.

IRC S40 Alcohol Fuels Credits

In addition to the excise tax exemptions for alcohol fuels, three types of alcohol fuel income tax credits exist under IRC S40. These credits are:

- Alcohol mixture credit
- Alcohol production credit
- Small ethanol producer credit

Whereas the small ethanol producer credit applies only to ethanol, either ethanol or methanol may qualify for the alcohol mixture credit and the alcohol production credit, as long as the ethanol or methanol is not produced from petroleum, natural gas, or coal (including peat).

The amount of the alcohol mixture credit is generally $0.60 per gallon for alcohol which is at least 190 proof, and $0.45 per gallon for alcohol which is of a proof ranging between 150 to 190. In the case of ethanol, however, the alcohol mixture credit is reduced to $0.54 for 190 proof ethanol, and to $0.40 for ethanol of a proof between 150 and 190. To qualify there must be a mixture of alcohol and gasoline (or any other liquid fuel which is suitable for use in an internal combustion engine).

IRC S179A Special Deduction for Alcohol Fuels Property

The 1992 Energy Act added under IRC S179A a special income tax deduction provision for certain equipment which would otherwise have to be capitalized and depreciated over a term of years. The special deduction may be used on "qualified clean-fuel vehicle property" and on "qualified clean-fuel vehicle refueling property." "Clean-fuel" includes natural gas, liquefied natural gas, liquefied petroleum gas, hydrogen, electricity, and any fuel which is at least 85 percent methanol, ethanol or any other alcohol. "Refueling property" is generally property used for storage or dispensing of clean fuel into a tank of a motor vehicle.

Accelerated Depreciation

Equipment in a powerplant or other facility that uses biomass or disposes of "waste" may qualify for a depreciation allowance.

Certain equipment in an electric generating plant that uses biomass for fuel qualifies for depreciation over 5 years using the 200 percent declining-balance method, provided the plant is a "qualifying small power production facility" within the meaning of the Public Utility Regulatory Policies Act. There may be a limit of 80 megawatts on size of the generating unit, depending on whether the fuel is classified as "biomass" or "waste" by the Federal Energy Regulatory Commission.

The following equipment qualifies: boilers, burners, pollution control equipment required by law to be installed, and equipment for "the unloading, transfer, storage, reclaiming from storage and preparation" at the place where the biomass will be used as fuel. This is basically all equipment up to the point where electricity is produced.

Tax-Exempt Financing

Assuming there is more than 10 percent private business use, most biomass projects will qualify for tax-exempt financing only if they fit into one of two categories:

- Two-county rule. A project can be financed in the tax-exempt bond markets if it supplies gas or electricity to an area no larger than two contiguous counties or one city and a contiguous county.

- Solid waste disposal facility. Tax-exempt financing can be used for a project that disposes of solid waste, which means "useless, unused, unwanted, or discarded solid material which has no market or other value at the place where it is located."

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Only two parts of a project qualify for tax-exempt financing as a solid waste disposal facility. One is that part up to where the first marketable product is produced.

The other part is the equipment at the back end that disposes of ash and other solid pollutants.

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NEW SMALL BUSINESS INNOVATION RESEARCH PROJECTS DESCRIBED

The Small Business Innovation Research (SBIR) program is designed for implementation in three phases, with Phase I determining the scientific or technical merit and feasibility of ideas proposed for investigation. The period of performance in this initial phase is about 6 months. Phase II is the principal research or research and development effort, and the work is performed in a period of up to 2 years. Phase III is the commercial application of the research or research and development effort by the small businesses using non-federal funding or alternatively, it may involve follow-on non-SBIR federal contracts.

Phase I awards have been made in fiscal year 1993 under the United States Department of Energy (DOE) SBIR program. The 168 Phase I projects were selected from a total of 1,999 grant applications received in response to the 1993 DOE annual SBIR solicitation. The 1993 solicitation contained 37 technical topics in the areas of basic energy sciences, health and environmental research, high energy and nuclear physics, magnetic fusion energy, energy efficiency and renewable energy, fossil energy, nuclear energy, and environment, safety, and health. Awards of interest relating to fossil energy were listed in the Face Synthetic Fuels Report, September 1993 (page 1-4). Descriptions of the work to be carried out under some of those awards are given below.

Removal of Volatile Metals From High Temperature Coal Conversion Gas Streams

The development of sorbents to remove volatile metal emissions at high temperatures from coal conversion systems is the objective of a project being conducted by ADA Technologies, Inc. Twelve candidate sorbents will be evaluated during Phase I laboratory testing at high temperature using a gas stream simulating an actual coal conversion stream. Mercury will be used as a surrogate volatile metal for the tests. Reacted sorbents will be subjected to a comprehensive series of analytical tests to determine the fundamental mechanisms involved in capturing the mercury.

Data to be obtained include absorptive capacities, sorption capabilities as a function of temperature and residence time, reaction product composition, reaction sites, and reacted sorbent stability. Selected sorbents will be evaluated further during Phase II to evaluate physical treatments (pelletizing), and long-term stability.

Oxide-Based Ceramic Composite Hot Gas Filter Development

Oxide fiber-oxide matrix ceramic composites are excellent candidates as hot gas particulate filters for use in clean coal conversion systems. They show greater toughness and mechanical strength than porous monolithic ceramic filters. The selection of oxide constituents will provide the highest corrosion resistance against coal combustion and gasification byproducts.

Oxide-oxide composite filter samples in tubular geometry will be developed by Ceramic Composites, Inc. in Phase I. Low-cost preform fabrication techniques will be used based on chemical vapor infiltrated boron nitride interfaces and oxide matrices of alumina and zirconia. The oxide-oxide composite filter structures will be tested for coal particulate filtration efficiency and durability. Post test microstructural and chemical analyses will provide guidance for composite processing improvements and scaleup in Phase II.

Direct Sulfur Reduction in Advanced Coal Conversion Processes

Cost-effective Direct Sulfur Reduction Processes (DSRP) are being investigated for producing elemental sulfur from sulfur dioxide generated in hot fuel gas cleanup systems.

Core Technologies, Inc. is working to determine whether a new electrodeless radio frequency plasma system described as plasma electron dissociation would be a viable DSRP to be used in conjunction with mixed metal-oxide systems to produce elemental sulfur from the hot regeneration offgas. Planned work in Phase I includes conducting tests with simulated gas input to evaluate operating performance (e.g., conversion rate versus throughput), estimate operating costs, and project capital costs for scaled-up systems. The project will include testing a computer model of the plasma operation and validating it with experimental data.
Furthermore, limited tests will be conducted to demonstrate its flexibility to reduce other pollutants, particularly nitrogen oxides.

**Carbonate Fuel Cell Monolith for Low-Cost and High Power-Density Operation**

This project, being conducted by Energy Research Corporation, is aimed at improvement in power density and lowering of carbonate fuel cell costs. Commercial applications of carbonate fuel cells can be significantly expanded if the power density is increased by a factor of 3 (from 1 to 3 kilowatts per square meter). Such an increase would not only lower the powerplant and stack replacement cost, but also improve volumetric and weight densities. The emphasis of this project will be to achieve a quantum jump in power density with accompanying cost benefits by innovative cell design. A monolithic carbonate fuel cell design using thin electrodes is planned in Phase I for achieving high power-density operation and reduction of cell materials use. This cell design makes high power-density operation feasible by providing 12 percent higher active area within the same geometric area, lowering mass transfer resistance of the anode as well as the cathode, and reducing cell internal resistance by about 60 percent.

**Advanced Ceramic Fibers for a Carbonate Fuel Cell Matrix**

Carbonate fuel cell life can be extended by improving the strength and thermal cycleability of the electrolyte matrix. The goal of electrolyte research planned by Energy Research Corporation is to improve the strength and thermal cycleability of the matrix by reinforcing it with strong ceramic fibers. A fiber manufacturing technology able to provide strong, robust fibers for reinforcing composite materials will be used to produce strong ceramic fibers stable in the carbonate electrolyte.

In the Phase I program, the matrix fabrication process will be improved to disperse the fiber uniformly. The fiber produced will be evaluated for its stability in molten carbonate. The fiber-reinforced matrix will be evaluated in out-of-cell thermal cycling testing. The fibers and matrix will be further optimized in Phase II in out-of-cell, single-cell, and sub-scale stack testing.

**Improved Carbonate Fuel Cell Design**

This project, being conducted by Energy Research Corporation, addresses the cost and performance of carbonate fuel cells that can readily use coal-derived fuels. Investigation of an innovative means for achieving reduced capital costs together with a streamlined system design is planned. A major opportunity for accomplishing these objectives exists in the area of anode offgas management by simplifying the method of recycling carbon dioxide to the fuel cell cathode. In Phase I, system design analysis, tradeoff analysis, and bench-scale fuel cell testing will be carried out.

**Clean High-Temperature Air Heater for Coal-Fired Gas Turbines**

An approach to significantly enhancing the efficiency, economy and environmental control capabilities of a combined-cycle, coal-fired powerplant is to apply presently available pulse combustion technology to a system that can use state-of-the-art materials, components, and sub-systems. The system consists of a high-temperature air heater for raising gas turbine compressor air temperatures to near turbine inlet requirements followed by supplementary turbine duct firing with natural gas to match turbine inlet air requirements. Emissions of nitrogen oxides, sulfur oxides, and particulates are reduced to lower levels than can be expected from solely increasing power generation efficiency.

Phase I of a project being conducted by Manufacturing and Technology Conversion International, Inc. will experimentally demonstrate the high flue-gas to compressor air heat transfer rates available from pulse combustion technology. It will also establish a matrix database for mass flow rates, pressure, and temperature that can be used in designing the high-temperature air heater section. In Phase II a reference integrated combined-cycle system can then be designed for feasibility systems studies of performance and economics as well as for sensitivity analysis, off-design analysis, and transient performance analysis (startup, shutdown, and upset conditions).
FINNISH COMPANIES MAKING PROGRESS IN PRESSURIZED GASIFICATION

Finnish enterprises are developing pressurized gasification technology for power production from coal and biofuels. According to the Finnish Foreign Trade Association, a cleaner and more efficient technology is set for a breakthrough in the late-1990s.

The simplest pressurized gasification power system is based on gasification with air followed by hot gas filtration. The clean fuel gas is then burned in a gas turbine connected to a generator producing electricity.

An IGCC (Integrated Gasification Combined Cycle) powerplant is more sophisticated than this. The first part of the process is the same as the above, but the thermal energy from the gas expanding in the gas turbine is transferred in a heat recovery steam generator to a pipeline which takes superheated steam to a steam turbine. The gas turbine produces two-thirds of the total electricity output of the plant and the steam turbine, making use of the secondary heat, one-third.

In a modern condensing powerplant applying present technology the electricity production efficiency is 40 to 42 percent, while with pressurized gasification systems this can be increased up to 50 percent.

Even more improvement can be achieved in combined heat and power generation, where the ratio of electricity-to-heat production nowadays is in the region of 0.2 to 0.5. According to E. Kurkela, of the Technical Research Center of Finland, with the pressurized gasification system this ratio increases to above 1. Thus, more electricity can be produced in cogeneration plants with high overall efficiency.

In Finland, solid fuel IGCC technology has been studied and developed in the Technical Research Center’s fuel technology laboratory at Otaniemi. Ahlstrom (and its subsidiary Bioflow Ltd.), Tampella Power Oy (and its subsidiary Enviropower Oy), and Imatran Voima have also invested extensively in this technology. The research and development work has been focused on gasification itself, solid fuel drying and pressurized feeding, gas filtration and materials durability.

Ahlstrom’s and Tampella Power’s systems differ in regard to their gasifier. Ahlstrom has a so-called circulating bed gasifier for biomass gasification, while Tampella Power has an agglomerating fluidized bed gasification system developed for biomass and coal gasification.

An IGCC powerplant in terms of investment costs is estimated to be about on a par with a conventional steam powerplant of a similar electricity output and equipped with sulfur and nitrogen reduction systems. However, the emission levels are much lower.

Enviropower

Enviropower tests gasification fuels in its 15-megawatt pilot plant, built in its research and development center in Tampere.

A series of tests on coal made over a 1-year period and an almost equally long set of tests on wood-based biomass have yielded encouraging results.

The gas obtained is considered to be extremely suitable for combustion in gas turbines, and the process appears ready for scaleup.

Enviropower is also supplying an approximately 100 megawatt coal gasification powerplant process to the United States, with startup scheduled for 1998.

In addition, Enviropower is planning to build a biomass-based powerplant in Finland.

The main applications of Enviropower’s gasification process are expected to be medium-range gasification powerplants for utilities and pulp and paper mills. Aside from its suitability for new power stations, the process can also be used for upgrading electricity output in existing plants.

Enviropower’s expertise is associated with a unique gasification island comprising the fuel feed system, reactor and gas cleanup. The rest of the process consists of conventional technology for combined heat and electricity.

The gasifier operates at a temperature range of 800 to 950°C, and generates a low heating value gas of 4 to
5 megajoules per kilogram thermal value. A pressure of 20 to 25 bar is used, determined by gas turbine requirements. The product gas leaving the gasifier is cooled in a special gas cooler to 400 to 500°C, which is suitable for gas turbine control valves and other downstream equipment.

The gasification process produces low emissions without the need for expensive purification systems. For instance, 98 to 99 percent of the sulfur can be removed.

A gasification powerplant also takes up less space than a conventional powerplant of equivalent output.

Varnamo Pressurized Biomass Gasification Plant

The Varnamo pressurized biomass gasification plant is the first of its kind in the world. The plant is almost 30 meters high and produces 6 megawatts of electricity and 9 megawatts of heat.

A 2-year demonstration program for the Varnamo plant began in the early autumn of 1993. The program is being conducted by the plant's constructors, the Finnish company, A. Ahlstrom Corporation and Sweden's largest privately owned utility, Sydkraft AB.

The process is expected to have particular application to pulp and paper mills. If a gasifier and a gas turbine are added to the powerplant of an existing pulp and paper mill, twice the quantity of electricity is obtained from the same amount of fuel.

Nordic pulp and paper mills typically make as little as 20 to 30 percent of their own electricity. Electricity production in relation to heat production is as low as 0.25 to 0.6. By adding a gasification type combined power and heat unit, this ratio can easily be increased to 0.7 to 0.9, or even as much as 1.2, which may raise the level of self-sufficiency to over 100 percent.

Ahlstrom is also designing a pressurized combustion plant of output 78 megawatts for the United States as part of the Department of Energy Clean Coal Technology Program.

The latest advances in Pyroflow technology are represented by the Pyroflow Compact, in which the cyclone collecting the circulating solids is integrated with the side of the furnace. The first plant of this kind (5.4 megawatts) is already running and a second (35 megawatts) is scheduled for completion in 1994.

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WOOD GASIFIER BEING DEVELOPED IN BRAZIL

The Brazilian Wood Biomass Integrated Gasification Gas Turbine (BIG-GT) Project (WBP) aims to demonstrate the commercial viability of BIG-GT technology in Brazil.

The project has been promoted by the expectation that hydroresources in Northeast Brazil will be fully tapped by the year 2000. The following factors also played a part in promoting the development of BIG-GT technology in Brazil:

- Numerous studies have concluded that the conversion of biomass into electricity may be a highly competitive option to produce electric energy
- Biomass, regarded as wood from plantations or bagasse from the sugar industry, represents a large potential resource
- The same technology can be used for wood and for bagasse
- Widespread use of biomass power may promote employment and economic development

This project was discussed in a paper presented by E. Carpentieri, of Companhia Hidro Eletrica do Sao Francisco, at the First Biomass Conference of the Americas, held in Burlington, Vermont in August.

Project Description

The scope of the WBP comprises the installation of a 30 megawatt demonstration powerplant based on the BIG-GT technology. A commercial enterprise will also be established to implement the construction, assembly, and operation of the plant.

The 30-megawatt powerplant is being conceived as a module for future commercial units, which could have
an installed capacity in the range of 60 megawatts or larger, depending on site conditions.

The BIG-GT concept, in conjunction with a combined cycle configuration, is aimed to give the demonstration plant an overall efficiency of about 43 percent. The plant is being designed to be fueled by wood chips as its main fuel, but it also will run with bagasse for some of the time during a test period.

The project has been conceived to be developed in the five phases listed below:

- Phase I, initial basic studies
- Phase II, equipment development, basic engineering and institutional infrastructure development
- Phase III, implementation (construction and assembly)
- Phase IV, demonstration
- Phase V, commercial operation


Phase II involves preparation for the implementation of the demonstration plant, and development of the plant's main equipment and basic engineering. It also has the objective of setting up all the infrastructure, mainly the institutional and organizational aspects, required to proceed with Phase III of the project.

Its major activities are as follows:

- Equipment development
- Basic engineering
- Site selection
- Energy sales contract
- Fuel supply contract
- Economic and financial studies
- Phase III planning and funding

A "two leg approach" has been adopted, which consists of developing two separate designs until sufficient technical and economic information has been generated to identify which is the best.

The Termiska Processor AB team has the responsibility to design the demonstration plant based on atmospheric gasification, and the Bioflow team will use the pressurized concept.

A third team will design and engineer the modifications to be introduced in the gas turbine, which will be used by both gasification teams. This responsibility has been allocated to General Electric.

Project Parties

The Global Environmental Facility is the main source of funds for the project.

The United Nations Development Program (UNDP) is the executing agency for the $7.7 million grant for Phase II.

The World Bank will play, in Phase III, the same role that UNDP is playing in Phase II.

The Federal Government of Brazil is the counterpart of UNDP, the recipient of the Global Environmental Facility grant, and has the official responsibility for the project development.

The following companies are involved in the project:

- Fundacao de Ciencia e Tecnologia
- Companhia Vale do Rio Doce
- Centrais Eletricas Brasileiras
- Shell Brazil and Shell International
- Companhia Hidro Eletrica do Sao Francisco

The following companies are developing equipment for the project:

- General Electric
- Termiska Processor AB
- Bioflow

Extension Toward Cogeneration

Given the large sugarcane industry existing in Brazil, and its enormous potential for cogeneration, an extension of the scope of the project to cover this area is under consideration.

Copersucar is leading the cogeneration extension of the WBP.

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COMING EVENTS

MARCH 2, CALGARY, ALBERTA, CANADA -- 11th Annual Heavy Oil and Oil Sands Symposium

MARCH 2-4, NEW PLYMOUTH, NEW ZEALAND -- New Zealand Gas Industry Conference

MARCH 10-11, GOLDEN, COLORADO -- 17th Annual Symposium of the Rocky Mountain Fuels Society

MARCH 13-18, SAN DIEGO, CALIFORNIA -- American Chemical Society 207th National Meeting

MARCH 16-17, LONDON, UNITED KINGDOM -- Royal Society Meeting on Technology in the Third Millennium: Energy

MARCH 20-22, SAN ANTONIO, TEXAS -- National Petroleum Refiners Association 92nd Annual Meeting

MARCH 20-23, CALGARY, ALBERTA, CANADA -- Recent Advances in Horizontal Well Applications

MARCH 21-23, GENEVA, SWITZERLAND -- Meeting of Experts on Clean Coal Technologies

MARCH 21-23, TRONDHEIM, NORWAY -- Eurogas 94, The European Applied Research Conference on Natural Gas

MARCH 21-24, CLEARWATER, FLORIDA -- 19th International Technical Conference on Coal Utilization and Fuel Systems

MARCH 23-25, WASHINGTON, D.C. -- Fifth Annual U.S. Hydrogen Meeting

MARCH 23-25, ATLANTA, GEORGIA -- Commercial and Investment Opportunities in Power Generation in China

APRIL 12-14, SINGAPORE -- Asian Natural Gas V

APRIL 17-20, TULSA, OKLAHOMA -- SPE/DOE Ninth Symposium on Improved Oil Recovery

APRIL 17-21, ATLANTA, GEORGIA -- American Institute of Chemical Engineers Spring National Meeting

APRIL 25-27, ATLANTA, GEORGIA -- Institute of Gas Technology's Energy Modeling Conference

APRIL 25-27, CHICAGO, ILLINOIS -- 56th Annual American Power Conference

APRIL 26-29, PALM SPRINGS, CALIFORNIA -- Alternate Energy 94, Council on Alternate Fuels

MAY 1-4, TORONTO, ONTARIO, CANADA -- Canadian Institute of Mining, Metallurgy and Petroleum 96th Annual General Meeting

MAY 9-13, GATLINBURG, TENNESSEE -- 16th Symposium on Biotechnology for Fuels and Chemicals

MAY 17-19, COLOGNE, GERMANY -- Power-Gen '94: Power Generation Conference

MAY 29-JUNE 1, STAVANGER, NORWAY -- 14th World Petroleum Congress

JUNE 5-11, FRANKFURT am MAIN, GERMANY -- ACHEMA, International Meeting on Chemical Engineering and Biotechnology
JUNE 11-16, SNOWBIRD, UTAH -- 14th North American Meeting of the Catalysis Society

JUNE 15-16, LONDON, ENGLAND -- Conference on Power Generation and the Environment

JUNE 20-23, MILAN, ITALY -- 19th World Gas Conference

JUNE 20-24, COCOA BEACH, FLORIDA -- 10th World Hydrogen Energy Conference

JUNE 21-22, HONOLULU, HAWAII -- 1994 Meeting of the International Energy Workshop

JUNE 27-29, NEW DELHI, INDIA -- Ninth Pacific Rim Coal Conference

JUNE 27-30, KRASNOYARSK, RUSSIA -- Second Workshop Meeting on C1-C3 Hydrocarbon Conversion

JULY 6-8, FLORENCE, ITALY -- Florence World Energy Research Symposium

AUGUST 7-12, MONTEREY, CALIFORNIA -- Intersociety Energy Conversion Engineering Conference

AUGUST 21-26, WASHINGTON, D.C. -- American Chemical Society, 208th National Meeting

AUGUST 23-25, HONG KONG -- Power-Gen Asia '94

SEPTEMBER 12-16, PITTSBURGH, PENNSYLVANIA -- 11th Annual International Pittsburgh Coal Conference

OCTOBER 1-6, PHOENIX, ARIZONA -- International Joint Power Generation Conference

OCTOBER 4-7, ROTTERDAM, THE NETHERLANDS -- Fifth International Conference on Stability and Handling of Liquid Fuels

OCTOBER 13-14, CAPE TOWN, SOUTH AFRICA -- World Energy Council Regional Energy Forum, Mobilizing Energy for Growth

OCTOBER 17-19, TSUKUBA CITY, JAPAN -- International Energy Agency Workshop on Clean Coal Technology

OCTOBER 25-27, PORTLAND, OREGON -- Eighth Cogen-Turbo Power Congress and Exhibition

OCTOBER 31-NOVEMBER 1, PRAGUE, CZECH REPUBLIC -- Smokeless Fuels From Brown Coal Workshop

OCTOBER 31-NOVEMBER 1, PRAGUE, CZECH REPUBLIC -- Least-Cost Options for Utilization of Brown Coal

NOVEMBER 1-5, PRAGUE, CZECH REPUBLIC -- Energy and Environment: Transitions in East Central Europe

NOVEMBER 28-DECEMBER 1, SAN DIEGO, CALIFORNIA -- 1994 Fuel Cell Seminar

DECEMBER 7-9, ORLANDO, FLORIDA -- Power-Gen Americas '94

DECEMBER 12-15, BALI, INDONESIA -- International Conference on Fluid and Thermal Energy Conversion
LITTLE CHANGE REPORTED ON STATUS OF STUART PROJECT

The activities of Southern Pacific Petroleum NL and its associate Central Pacific Minerals NL during the December quarter have been reported in their December 1993 quarterly report.

During the quarter, the Customs and Excise Legislation Amendment Bill 1993 was passed by Australia's Federal Parliament. As a result, the Stuart Stage 1 Project is able to benefit, directly, by the amount of gasoline excise foregone by the government on up to 600,000 barrels per year of gasoline produced from Stuart naphtha production until the year 2005.

At current gasoline excise rates (which are adjusted semi-annually to reflect inflation), a benefit of up to A$28.2 million per year can be expected. The legislation is designed to encourage approved oil shale demonstration plants such as Stuart Stage 1.

Arrangements for the grant of a formal Mining Lease for Stage 1 for a term of 24 years are proceeding following the Mining Warden's recommendations to the Queensland Minister for Minerals and Energy during the quarter. The satisfactory conclusion of an environmental impact assessment study forms part of the Mining Lease procedure. (See the Pace Synthetic Fuels Report, December 1993, page 2-12.)

###
CORPORATIONS

RAMEX GETS FINANCING FOR FURTHER OIL SHALE GASIFICATION WORK

Ramex Synfuels International, Inc., has obtained new financing for its oil shale gasification program. As reported in the company's September 1993 Quarterly Report, a private placement of limited partnership interests in Ramex Research Partners, Ltd., successfully closed at $110,000.

As of November, Ramex was attempting to obtain additional financing for Phases 2, 3 and 4 of the development and testing of its in situ oil shale gasification process. A contract was signed in January with a nationally recognized laboratory to conduct the first-phase test of the gasification process.

####
ECONOMICS

BYPRODUCT MARKET POSSIBILITIES EXAMINED FOR EASTERN OIL SHALE

Both established and potential oil shale product and byproduct markets have been examined for Eastern United States oil shales. These products and byproducts include trace elements, sulfur, cement, asphalt, bricks, fixed gases, specialty carbon fibers, adsorbent carbons, chemicals, and chemical feedstocks. Market evaluations, for the most part, are based on the yields of byproducts anticipated from an Eastern United States oil shale using KENTORT fluidized-bed technology in a 7,500-short ton per day plant.

Marketing or utilization of products and byproducts that are either unavailable or more costly to produce from petroleum was emphasized. The objectives of the study were to:

- Estimate the yields of known or potential oil shale products and byproducts
- Survey the domestic market size and price
- Explore potential plant configurations or associations with other industries that might enhance oil shale commercial viability

This work was conducted by D.N. Taulbee, et al., of the Kentucky Center for Applied Energy Research (CAER). It was described in a paper presented at the Eastern Oil Shale Symposium, held in Lexington, Kentucky in November.

Basis for Product Estimates

Product or byproduct yields are highly dependent on the starting shale and the technology utilized. Accordingly, three cores that had been extensively analyzed at CAER were used as a basis for estimating byproduct yields. These cores are reasonably representative of the deposits of Northeastern Kentucky, the region believed to be one of the more promising for commercial development in the Eastern United States.

KENTORT II, developed specifically for Eastern United States shales, was selected as the processing technology.

Offgases

Table 1 shows offgas production rates from a previous CAER study. For each of the listed components, the domestic market for 1992 was quite large and thus unlikely to be affected by an influx of these components from a fledging oil shale industry. The production values per Mg (megagram) were generated from average market price and production rate data. Considering the added capital costs of gas purification and the fact that most plant configurations require combus-

<table>
<thead>
<tr>
<th>Gas Component</th>
<th>Production Rate/Mg Shale</th>
<th>Domestic Sales</th>
<th>Domestic Price ($US)</th>
<th>Production Value/Mg Shale ($/Mg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen</td>
<td>4,000 (0.35)</td>
<td>4.6 trillion l</td>
<td>0.13/1,000 l</td>
<td>0.52</td>
</tr>
<tr>
<td>Methane</td>
<td>4,000 (2.8)</td>
<td>560.0 billion l</td>
<td>0.07/1,000 l</td>
<td>0.28</td>
</tr>
<tr>
<td>Ethylene</td>
<td>500 (0.6)</td>
<td>8.1 billion kg</td>
<td>0.40/kg</td>
<td>0.25</td>
</tr>
<tr>
<td>Ethane</td>
<td>950 (1.3)</td>
<td></td>
<td>0.46/kg</td>
<td>0.59</td>
</tr>
<tr>
<td>Propylene</td>
<td>450 (1.9)</td>
<td>9.8 billion kg</td>
<td>0.36/kg</td>
<td>0.32</td>
</tr>
<tr>
<td>Butene</td>
<td>300 (0.6)</td>
<td>0.43 billion kg</td>
<td>0.44/kg</td>
<td>0.28</td>
</tr>
<tr>
<td>Ammonia</td>
<td>(0.5)</td>
<td>13.2 million Mg</td>
<td>100.0/Mg</td>
<td>0.06</td>
</tr>
</tbody>
</table>
tion of gaseous hydrocarbons to meet thermal input requirements, it is unlikely that any of the components in Table 1 would substantially impact economics with the possible exception of hydrogen. Even here, if oil upgrading is part of the processing strategy, insufficient hydrogen would remain to justify the cost of recovery.

**Liquid Hydrocarbons**

Marketing the liquid product can follow one (or more) of three schemes:

- Selling the entire stream
- Marketing individual components
- Marketing broad classes of components, e.g., asphalt, BTX, basic fractions, etc.

The only market thought to be large enough to absorb the entire liquid stream would be the petroleum refining industry.

In today's market $35+ per barrel shale oil simply cannot compete with $15 to $18 per barrel crude oil. Thus, operating an oil shale plant solely to produce motor fuels is not profitable in today's market.

It has been proposed that isolating individual liquid components with high market value can greatly enhance process economics. In one study, the market value of components that could feasibly be isolated from Western shale oils, e.g., olefins, phenols, etc., was estimated in the range of $100 per barrel. However, Taulbee, et al., cite two key considerations. The first is isolation costs. Isolation costs depend on factors such as starting concentration, the chemical/physical properties of the component being isolated, and the required purity. It is estimated that the minimum cost of isolation and purification of hydrocarbon components from a complex feed stream is on the order of $2.20 per kilogram.

A second consideration is the impact of even a single oil shale plant on the market price of a given component. If the byproduct market is large enough to absorb additional production from an oil shale plant, then a minimal suppression of shale price can be anticipated. However, it may be a mistake to assume that the sale price of components with small markets would be unaffected by increased production capacity. A survey of market size and price for hundreds of organic chemicals revealed no chemical, with an annual market in excess of 45 million kilograms per year, that was marketed for more than $2.20 per kilogram. With only one exception, no chemical marketed in excess of 450,000 kilograms per year commanded a price greater than $7.70 per kilogram. On a small scale, sale prices of $5 to $20 per kilogram for certain chemicals might be realized.

However, there are numerous shale oil components which are absent or in low concentration in petroleum crudes, whose abundance, relative ease of isolation, and market size make them attractive candidates for isolation.

Selected components that meet the criteria of large markets and reasonable isolation costs are shown in Table 2.

Converting the least volatile shale oil fraction to a paving asphalt or to an asphalt modifier has been considered to be the most viable approach to small-scale commercialization.

The July 1993 price for commercial-grade AC-20 asphalt averaged $109.35 per ton. This equates to approximately $19 per barrel, near the price of petroleum crude and insufficient to make asphalt from oil shale profitable.

To overcome this impediment, shale oil could be marketed as an asphalt modifier, which sells for 2 to 3 times more than commercial asphalt. It is yet to be demonstrated that Eastern shale oils will produce a modifier that can improve pavement performance sufficiently to command the higher prices.

Market limitation is also a factor. The total United States paving asphalt market in 1992 was 21.1 million Mg. More importantly, due to prohibitive shipping costs, the regional market for Kentucky and nearby states (Alabama, Tennessee, Indiana, and Ohio) totaled approximately 3.6 million Mg. Assuming approximately two-thirds of the total liquid product could be converted to an asphalt modifier, a 6,800-Mg per day plant would produce approximately 90,000 Mg per year. Adding the modifier to commercial asphalt at a level of 10 weight percent would require an improbable regional market penetration of approximately 25 percent. An obvious solution is to simply construct a smaller plant (with an accompanying loss in economy of scale). In any case, it would appear that no more than one to two small plants could be supported by
revenue from the asphalt market. The asphalt market could provide critical cash flow for a fledgling industry as it progressed along the learning curve to higher efficiency.

Carbon fibers is another byproduct that can be obtained from shale oil.

Recently, using a shale oil asphaltene fraction as the starting material, it was shown that continuous filament, isotropic, carbon fibers were successfully produced and steam activated to produce high surface areas.

Comparison with a commercial petroleum pitch shows that the oil shale precursor offers advantages in terms of simplicity of feedstock preparation, excellent spinability, and more facile processing, all of which could reduce production costs, according to Taulbee, et al. The activated shale oil-based fibers also contained a much higher proportion of mesopores (2 to 50-nanometer diameter) and higher nitrogen content than petroleum-based fibers, which could lead to novel adsorptive properties. This was confirmed by a recent evaluation of the shale oil-based fibers which demonstrated a high catalytic activity with respect to reduction of NO in the presence of NH₃ and for oxidation of SO₂ to H₂SO₄, both at ambient temperature. While the high nitrogen content of residual oil shale liquids can be detrimental to their upgrading to distillate fuels, it may be possible to use this attribute to advantage in the production of value-added carbon materials. Because such utilization represents an area in which shale oils have an apparent potential advantage over petroleum crude, further investigation is clearly warranted.

Solids Utilization

Table 3 lists typical concentrations of the major inorganic elements in the Kentucky oil shale deposits. Column 3 lists the portion of these elements that can be extracted with either H₂SO₄ or HCl following combustion at 750°C. Coupling raw shale concentration and the extractable portion gives the kilograms per megagram available for each element (Column 4). The fifth and seventh columns show the form in which the element may be marketed and the market price for that form. The last column shows dollars per megagram of pure element if marketed in the form indicated. Market size data represent the total market (pure element basis) regardless of the marketed form. Analogous information for trace elements is shown in Table 4. A percent extractable figure was unavailable for many of the trace elements and so a conservative 50 percent extractable value was assumed.

Several elements in Tables 3 and 4 appear to merit serious cost analysis. Sulfur is the element most likely to be marketed, because in most process configurations, and particularly in the KENTORT reactor, up to 90 percent of the total sulfur in Eastern shales is liberated as H₂S. This necessitates designing for sulfur recovery regardless of its byproduct value. Other elements of potential benefit include Al, Fe, K, Mg, Co, Cr, and Ni, as well as V, though marketing of the latter...
### TABLE 3

**MAJOR INORGANIC ELEMENTS**

<table>
<thead>
<tr>
<th>Element</th>
<th>Raw Shale Concent. (ppm)</th>
<th>Extract. %</th>
<th>kg/Mg Shale</th>
<th>Form</th>
<th>Domestic Market (Mg)</th>
<th>Domestic Price/Mg ($US)</th>
<th>Value/Mg Shale ($US)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Al</td>
<td>6.7%</td>
<td>77</td>
<td>52</td>
<td>$\text{Al}_2\text{O}_3$</td>
<td>4,900,000</td>
<td>$212</td>
<td>$20.60</td>
</tr>
<tr>
<td>Ca</td>
<td>0.38</td>
<td>96</td>
<td>3.6</td>
<td>$\text{CaCl}_2$</td>
<td>343,000</td>
<td>157</td>
<td>1.60</td>
</tr>
<tr>
<td>Fe</td>
<td>4.1</td>
<td>99</td>
<td>41</td>
<td>$\text{Fe ore}$</td>
<td>70,000,000</td>
<td>40</td>
<td>2.60</td>
</tr>
<tr>
<td>K</td>
<td>2.9</td>
<td>71</td>
<td>21</td>
<td>$\text{K}_2\text{SO}_4$</td>
<td>490,000</td>
<td>200</td>
<td>9.10</td>
</tr>
<tr>
<td>Mg</td>
<td>0.68</td>
<td>93</td>
<td>6.3</td>
<td>$\text{MgO}^4$</td>
<td>265</td>
<td>3.15</td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>0.10</td>
<td>92</td>
<td>0.9</td>
<td>Tri-phosphate</td>
<td>150</td>
<td>1.20</td>
<td></td>
</tr>
<tr>
<td>S</td>
<td>3.1</td>
<td>67</td>
<td>21</td>
<td>Elem S</td>
<td>12,900,000</td>
<td>60</td>
<td>1.26</td>
</tr>
<tr>
<td>Ti</td>
<td>0.40</td>
<td>10</td>
<td>0.4</td>
<td>$\text{TiO}_2$</td>
<td>1,135,000</td>
<td>2,060</td>
<td>1.38</td>
</tr>
</tbody>
</table>

### TABLE 4

**TRACE ELEMENTS**

<table>
<thead>
<tr>
<th>Element</th>
<th>Raw Shale Concent. (ppm)</th>
<th>Extract. %</th>
<th>kg/Mg Shale</th>
<th>Form</th>
<th>Domestic Market (Mg)</th>
<th>Domestic Price/Kg ($US)</th>
<th>Value/Mg Shale ($US)</th>
</tr>
</thead>
<tbody>
<tr>
<td>As</td>
<td>47</td>
<td>50</td>
<td>0.024</td>
<td>As</td>
<td>22,000</td>
<td>$0.63</td>
<td>$0.01</td>
</tr>
<tr>
<td>Ba</td>
<td>497</td>
<td>50</td>
<td>0.294</td>
<td>$\text{BaSO}_4$</td>
<td>513,000</td>
<td>0.04</td>
<td>0.02</td>
</tr>
<tr>
<td>Cd</td>
<td>22</td>
<td>50</td>
<td>0.011</td>
<td>Cd</td>
<td>3,400</td>
<td>2.20</td>
<td>0.02</td>
</tr>
<tr>
<td>Co</td>
<td>18</td>
<td>96</td>
<td>0.017</td>
<td>Co</td>
<td>7,200</td>
<td>50.25</td>
<td>0.88</td>
</tr>
<tr>
<td>Cr</td>
<td>160</td>
<td>79</td>
<td>0.126</td>
<td>$\text{Cr}_2\text{O}_3$</td>
<td>12.10</td>
<td>2.24</td>
<td></td>
</tr>
<tr>
<td>Cr</td>
<td>145</td>
<td>94</td>
<td>0.136</td>
<td>Chromite ore</td>
<td>435,000</td>
<td>0.11</td>
<td>0.04</td>
</tr>
<tr>
<td>Mn</td>
<td>149</td>
<td>95</td>
<td>0.142</td>
<td>MnO2</td>
<td>355,000</td>
<td>1.57</td>
<td>0.33</td>
</tr>
<tr>
<td>Mo</td>
<td>133</td>
<td>97</td>
<td>0.129</td>
<td>Mo</td>
<td>17,200</td>
<td>5.08</td>
<td>0.65</td>
</tr>
<tr>
<td>Ni</td>
<td>149</td>
<td>95</td>
<td>0.142</td>
<td>Ni</td>
<td>145,000</td>
<td>7.08</td>
<td>1.00</td>
</tr>
<tr>
<td>Pb</td>
<td>122</td>
<td>50</td>
<td>0.061</td>
<td>Pb</td>
<td>1,230,000</td>
<td>0.80</td>
<td>0.04</td>
</tr>
<tr>
<td>Sb</td>
<td>32</td>
<td>50</td>
<td>0.016</td>
<td>Sb</td>
<td>42,600</td>
<td>1.75</td>
<td>0.03</td>
</tr>
<tr>
<td>Se</td>
<td>27</td>
<td>50</td>
<td>0.014</td>
<td>Se</td>
<td>510</td>
<td>11.40</td>
<td>0.16</td>
</tr>
<tr>
<td>Sr</td>
<td>105</td>
<td>75</td>
<td>0.079</td>
<td>Sr</td>
<td>30,000</td>
<td>0.07</td>
<td>0.06</td>
</tr>
<tr>
<td>Th</td>
<td>10</td>
<td>50</td>
<td>0.005</td>
<td>$\text{ThO}_2$</td>
<td>54</td>
<td>63.80</td>
<td>0.32</td>
</tr>
<tr>
<td>V</td>
<td>803</td>
<td>92</td>
<td>0.739</td>
<td>$\text{V}_2\text{O}_5$</td>
<td>3,800</td>
<td>5.75</td>
<td>7.60</td>
</tr>
<tr>
<td>Y</td>
<td>47</td>
<td>63</td>
<td>0.030</td>
<td>$\text{Y}_2\text{O}_3$</td>
<td>700-wld</td>
<td>147.00</td>
<td>4.42</td>
</tr>
<tr>
<td>Zn</td>
<td>581</td>
<td>84</td>
<td>0.488</td>
<td>$\text{Zn}$</td>
<td>1,220,000</td>
<td>1.30</td>
<td>0.63</td>
</tr>
<tr>
<td>Zr</td>
<td>156</td>
<td>50</td>
<td>0.078</td>
<td>Zr sponge</td>
<td>55,000</td>
<td>22.00</td>
<td>1.72</td>
</tr>
</tbody>
</table>
may suppress the market price. The cumulative value for these elements in the indicated form and excluding V is $59 per megagram. The recovery of these elements would be costly, both in terms of capital investment and operating expenses. However, with a cumulative potential market value approximately 10 times that of oil, extractive recovery of these elements has the potential to favorably impact economics.

Spent shale residues have historically been utilized for brick production. Both the oil shale and brick plant stand to benefit from sharing costs associated with mining, crushing, and spent shale disposal. In addition, excess combustible gas from retorting can be used to help meet heating requirements in the brick plant.

In 1993, the United States brick market was approximately 8 billion standard units with annual sales of approximately $1.5 billion. The regional market (Kentucky, Illinois, Indiana, Tennessee, Alabama, and Georgia) was approximately 1.5 billion units. Brick production requires a plastic clay as a feed material. With the exception of organic matter and pyrite, the clays used are often otherwise similar to those in the Eastern shale deposits. In at least one local plant, clays situated directly above the New Albany oil shale are mined. The underlying oil shale is deemed unsuitable due to significant amounts of carbon, which can result in swelling and black coring of the brick during firing, and pyrite, which can lead to swelling and elevated SO2 emissions. Complicating matters, combustion of the shale to remove residual carbon and sulfur results in the loss of clay plasticity.

These factors suggest that Eastern oil shales or spent shales are not suitable as clay substitutes in commercial brick production. However, due to the low porosity of many of the feed clays, calcined material or sand is often added to enhance porosity. This application represents a potential, though smaller, end-use for the combusted shale. Porosity enhancers are typically added in the range of 10 to 20 percent. This places an upper limit of approximately 1 million Mg in the regional market. More realistically, this limit would be established by the capacity of the brick plant(s) near which it is located. Nonetheless, there are legitimate arguments for locating an oil shale plant in close proximity to a brick plant when the latter is over or near the oil shale outcrops (not uncommon in this region).

Oil shale also shows potential for use in the production of portland cement.

Oil shale is already used to make portland cement in Germany, Russia, and China. Several other countries, to a lesser extent, have also adopted this technology.

In 1992, approximately 80 million Mg of portland cement was marketed domestically at an average price of $70.75 per Mg.

There are two reasons why oil shale is beneficial to cement production, say Taulbee, et al. Producing cement is an energy intensive process, generally requiring large amounts of coal and/or natural gas. Thus, the heating value, approximately 5,000 joules per gram for the Sunbury and hgz-Cleveland Member shales, can supply a significant portion of the required energy input. In addition, major oxides required in cement can be obtained from the shale matrix.

The combusted residue can also be fully utilized to offset constituents that otherwise must be added to the kiln, e.g., sand, gypsum, clay, and smelter slag.
NEW OPPORTUNITIES SEEN FOR HIGH-VALUE CHEMICALS FROM SHALE

The importance of developing ways to produce high-value chemicals and materials from oil shales, coals, and the liquids derived from them was discussed in a paper by C. Song and H. Schobert, of The Pennsylvania State University. The paper was presented at the 1993 Eastern Oil Shale Symposium, held in Lexington, Kentucky in November.

Song and Schobert considered the following:

- Issues that may impact the future utilization of coals and oil shales
- Importance of developing chemicals and materials as a collateral use of these resources
- Examples of advanced, high-value chemicals and materials that in principle could be derived from coals or oil shales

The amount of fossil hydrocarbon resources used for non-fuel purposes is small compared with the amount consumed as fuels. In 1992, the non-fuel uses represented 6.2 percent of total energy consumption in the United States. The non-fuel use of hydrocarbon resources is overwhelmingly the use of petroleum products, primarily asphalt and road oil, petrochemical feedstocks, and liquefied petroleum gases. Petroleum and natural gas account for more than 90 percent of the major industrial organic chemicals. Coal tars are an important source of aromatic chemicals. At present there is no commercial exploitation of oil shales as sources of chemicals or materials.

Fuels

Neither shale- nor coal-derived liquid are currently cost-effective compared with petroleum, and do not seem to be likely to compete with petroleum in the near future. Environmental regulations require that these fuels be subjected to extensive upgrading before they can be used as fuels.

However, economic analysis of the viability of oil shale conversion or coal liquefaction could well produce a different result if some of the components of these products could be used for making high-value chemicals or specialty materials.

The last 2 decades have witnessed enormous developments in various organic or carbon-based materials, and it is certain that the 1990s and the 21st century will see significant further growth of these materials. Examples include engineering plastics, liquid crystalline polymers, high-temperature heat-resistant polymers, polymer membranes, and carbon fibers. Many of the monomers for some of these newly developed high-performance materials are not readily available from petroleum. Thus an excellent opportunity exists to explore the potentials of developing high-value chemicals and specialty materials from coals, oil shales, or the liquids obtained from them, according to Song and Schobert.

The most significant single problem in using shale oils in conventional refineries is the high nitrogen content. This disadvantage can be turned to advantage, however, through the use of these oils as feedstocks to produce high-value nitrogen-containing polymers, such as engineering plastics.

Engineering plastics (or engineering resins) are materials that are capable of competing with die-cast metals such as zinc, aluminum, and magnesium in hardware, automobile components, and plumbing fittings. They sell at 2 to 4 times the price of the commodity plastics, and are now a $2 billion business in the United States. Furthermore, consumption of these materials is projected to increase at a 10 percent annual rate. A category of engineering plastics especially noteworthy are the so-called high-performance plastics, which are used when high strength or good dimensional stability is needed at high temperatures, as in aerospace applications. These high-performance plastics include the polyimides and the poly(amide-imide)s, and are among the most costly of the engineering plastics. Figure 1 shows some high-temperature heat-resistant polymer materials.

Because of their high chemical and thermal stabilities, polyimides have had a significant commercial impact.

Kapton, for example, is prepared from pyromellitic dianhydride and bis(4-aminophenyl) ether. The properties of this material include its ability to resist
temperatures of 400°C, show little weight loss to 500°C, be infusible, flame resistant, and insoluble in organic solvents. The mechanical properties and electrical insulating abilities are maintained even after long exposures at high temperatures. It is currently priced at about $50 per pound.

Many related materials, based on nitrogen-containing monomers, also show useful properties as engineering plastics. The poly(amide-imide)s are made from tricarboxylic acids and diamines, so that the resulting polymer includes both amide and imide linkages. Their mechanical properties are maintained up to 180°C, and they are used in jet engine parts and automobile parts.

Polybenzimidazole is now being produced commercially as a high-temperature fiber. These plastics are also of interest because of their ability to maintain their physical properties at least up to 250°C in air. Polybenzimidazoles have been used as laminates and adhesives for high-temperature aerospace applications, and the fibers are used in protective clothing and safety gloves.

The first commercial application of a liquid crystalline polymer, Du Pont’s Kevlar fibers, have a low resistance to axial compressive failure. The tensile strength of Kevlar is higher than that of steel, while its density is much lower. Kevlar is used in bullet-proof vests, but most of the Kevlar produced is used in tire cord. The most recent development in the family of Kevlar materials is Kevlar 149, which has mechanical properties suitable for the construction of high-performance components of helicopters. The average market value of the liquid crystalline polymer fibers is $10 per pound.

Films of polypyrrole show good mechanical strength, good stability in air up to about 300°C, and insolubility in organic solvents. Perhaps the most remarkable property of the polypyrroles is their change in both color and electrical conductivity on oxidation.

This property offers the possibility of using polypyrroles as electronic switches in display devices.

Various functional polymers have found applications in industrial separation of gaseous and liquid mixtures and in biomedical applications. Industrial separation processes represent a large use of membranes. Hollow-fiber membranes (also called capillary membranes) are used in water purification, water desalination, and blood fractionation. Some of the materials used to make these membranes include polyacrylonitrile, polyamides, and polybenzimidazoles. Aromatic polyamides are widely used for making membranes for ultra-filtration and reverse osmosis.

Carbon Materials in Relation to Shale Oils

Shale oils, particularly the heavy fraction, can also be used for making a variety of carbon materials. Researchers have used oil shale asphaltenes from KENTORT II processes to produce isotropic carbon fibers and activated carbon fibers. Due to their high nitrogen contents, the shale-oil based activated carbon fibers may have unusual adsorptive properties.

###

RECENT OIL SHALE PATENTS LISTED

Some recent patents issued by the United States Patent Office in the field of oil shale technology are listed in the following.
Balanced-Line RF Electrode System for Use in RF Ground Heating to Recover Oil From Oil Shale

U.S. Patent No. 5,236,039 issued to William A. Edelstein, et al., and assigned to General Electric Company is an in situ method of extracting oil from oil shale or tar sands by applying a radio frequency excitation signal to the hydrocarbon-bearing layer through a system of electrodes. The electrodes are inserted into a matrix of holes drilled through the surface layer and into the hydrocarbon-bearing layer. A coaxial line extending through the surface layer is connected to the electrodes extending into the hydrocarbon-bearing layer. The electrodes have a length that is an integral number of quarter wave lengths of the radio frequency energy. A matching network connected between the coaxial cable and the electrodes maximizes the power flow into each electrode, the electrodes are excited uniformly in rows and as a "balanced line" RF array where adjacent rows of electrodes are 180° out of phase. This method does not produce substantial heating of the surface layer or the region surrounding the producing layer, and concentrates most of its power in the hydrocarbon-bearing layer.

Oil Shale Beneficiation Process Using a Spiral Separator

U.S. Patent No. 5,192,422 has been issued to Bernard Y.C. So and assigned to Amoco Corporation. A stream containing kerogen-rich and mineral-rich oil shale particles flows in a downward helical course such that the stream is confined in a manner to give the stream an outer and upper side having a first depth and comprising a substantial amount of said kerogen-rich particles, and an inner and lower side having a second depth and comprising a substantial amount of said mineral-rich particles, the first depth being greater than the second depth. The kerogen-rich and mineral-rich particles are subsequently separated in order to recover the kerogen-rich particles. The mineral-rich particles are further processed using froth flotation.

Apparatus for Separating Oil and Precious Metals From Mined Oil-Bearing Rock Material

U.S. Patent No. 5,178,733 has been issued to Jay P. Nielson. It presents a method and apparatus for producing oil, bitumen, precious metals, and hydrocarbon gases from mined mineral such as tar sands and oil shale. The rock is ground, preconditioned in a heated and pressurized atmosphere devoid of oxygen, and subsequently centrifuged in the presence of an oil replacement gas to produce oil, and also any precious metal particles that are present in the oil-bearing rock material. The produced oil and precious metals are subsequently separated from each other by centrifuging.

Process for Biotechnological Upgrading of Shale Oil

U.S. Patent No. 5,143,827 has been issued to Jackie Aislabie and Ronald M. Atlas and assigned to Southern Pacific Petroleum. It concerns a process for biotechnological upgrading of shale oil in selectively removing damaging nitrogen-containing compounds by treating the raw shale oil with special microbial cultures having the specific ability to degrade the harmful nitrogen-containing compounds, such as the amines, nitriles, quinolines and pyridines, and converting them into non-damaging components.

SOLAR GASIFICATION OF OIL SHALE PROPOSED

At the NATO Advanced Study Institute on Composition, Geochemistry and Conversion of Oil Shales held in July of the last year in Akcay, Turkey, a paper by M. Paolucci of the University of Rome, Italy outlined a research program on the solar gasification of oil shales.

The objective stated by the researchers was to recover products with a low pollution potential (high hydrogen content) at high energy conversion efficiency in conversion reactors utilizing a solar energy source. Three phases were outlined for the project as follows:

- The pyrolysis of Italian oil shale in reactors using hydrogen-enriched methane coming from high-temperature thermochemical conversion processes.
- The pyrolysis products are gasified to produce a syngas. The syngas is enriched in hydrogen by reacting with steam (steam reforming).
- The use of solar thermal energy to warm air to a high temperature to supply heat for the pyrolysis and gasification processes.
Research is under way to select suitable catalysts to demonstrate the above process.

In order to reduce fluctuations due to the discontinuity of solar energy, a backup system returns part of the hydrogen produced in the reformer. It is claimed that high (80 percent) energy conversion efficiency can be obtained. This justifies the use of solar energy to transform oil shale more into hydrogen than into oil.
OIL SHALE RESOURCES OF THE PRIPYAT BASIN IN BYELORUSSIA DEFINED

Reserves of Upper Devonian oil shale were discovered in the Southern part of Byelorussia, in the Minsk and Gomel districts, in 1963 and 1964. The total area of the Pripyat oil shale basin has been estimated to be about 20,000 square kilometers. The total reserves of shale are estimated at 11 billion tons, of which 6.5 billion tons are at a depth below 300 meters. Up to now, two principal deposits, the Turovo and the Lyuban, have been delimited, their total reserves being 3.6 billion tons.

See Figure 1 for a map of the area.

Because there are potassium chloride reserves underlying the shale seams and also some mines producing this salt, the exploitation of these resources could perhaps be combined.

Turovo Deposit

The Turovo deposit is situated in the Southwestern part of the Pripyat oil shale basin. The area covered is 1,370 square kilometers, and the total reserves of oil shale are 2.7 billion tons. There are five principal seams of oil shale at depths of 0 to 680 meters, but only two of them can be considered to be of commercial value. These are seams I and II, which occur at depths of 80 to 600 meters.

The average heating value of the shale in the productive seams is 5.7 megajoules per kilogram, the ash content is 70 percent, carbon dioxide in carbonates is 12.7 percent, sulfur content is 2.6 percent, and oil yield (Fischer Assay) is 8.0 percent.

The existing (somewhat dubious) data on the ultimate composition of the Turovo shale kerogen are as follows in percentages:

- C, 77.4 to 77.8
- H, 9.8 to 10.1
- S, 2.0 to 2.2
- N, 0.5 to 0.6
- O, 9 to 10 (by difference)

On retorting it yields 45 to 56 percent of oil, and the heating value is 37.3 to 39.4 megajoules per kilogram.

The chemical composition of the shale ash in percent, on average, is as follows:

- SiO$_2$, 41.3
- Al$_2$O$_3$, 13.0
- Fe$_2$O$_3$, 6.8
- CaO, 21.8
- MgO, 3.2
- Na$_2$O, 0.3
- K$_2$O, 4.0
- SO$_3$, 3.8

Calcite, dolomite, quartz, hydromicas, pyrite, feldspar and glauconite have been identified in the mineral portion of the shale. The carbonaceous material accounts for 30 to 40 percent of the shale mineral matter.
Characteristics of the oil obtained by retorting of the Turovo shale are shown in Table 1.

Lyuban Deposit

The Lyuban deposit is located in the Northwestern part of the Pripyat oil shale basin. The area covered is about 600 square kilometers, and the total reserves are 0.9 billion tons. There are four principal seams of shale; of these, mostly seams I and II at depths of 80 to 580 meters may be considered to be of commercial value.

The heating value of the shale (on average) is 6.4 megajoules per kilogram, the ash content is 71 percent, the carbon dioxide content in carbonates is 11 percent, the sulfur content is 2.3 percent, and the oil yield is to 8 to 11 percent.

The Lyuban shale kerogen contains (in percent):

- C, 76.3 to 81.3
- H, 10.9 to 12.2
- S, 3.4 to 4.3
- O + N, 3.0 to 8.5 (by difference)

On retorting, it yields 55 to 70 percent of oil (Fischer Assay), with a heating value of about 38 megajoules per kilogram.

The chemical composition of ash, in percent, is:

- SiO$_2$, 36 to 38
- Al$_2$O$_3$, 10 to 11
- Fe$_2$O$_3$, 3 to 6
- CaO, 29 to 30
- MgO, 2 to 3
- SO$_3$, 5 to 7

The carbonaceous material accounts for 15 to 20 percent of the shale mineral portion. Montmorillonite, palygorskite, hydromicas, calcite, dolomite, quartz, feldspar and pyrite have been found in the mineral matter of the shale.

The characteristics of the oil, obtained by Fischer Assay, are shown in Table 2 (next page).

BALTIC OIL SHALE BASIN REVIEWED

An overview of the Baltic oil shale basin was presented by H. Bauert, of the University of North Carolina, at the NATO Advanced Study Institute: Composition, Geochemistry and Conversion of Oil Shales, held in Akcay, Turkey in July.

**TABLE 1**

CHARACTERISTICS OF TUROVO SHALE OIL

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density, g/cm$^3$</td>
<td>0.9307 - 0.9387</td>
</tr>
<tr>
<td>Heating Value, MJ/kg</td>
<td>41.2 - 42.5</td>
</tr>
<tr>
<td>Ultimate Composition, %</td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>79.8 - 82.0</td>
</tr>
<tr>
<td>H</td>
<td>10.8 - 12.1</td>
</tr>
<tr>
<td>S</td>
<td>0.8 - 1.2</td>
</tr>
<tr>
<td>N</td>
<td>0.4 - 0.5</td>
</tr>
<tr>
<td>O (by Difference)</td>
<td>5.6 - 7.3</td>
</tr>
<tr>
<td>Chemical Group Composition, %</td>
<td></td>
</tr>
<tr>
<td>Non-Aromatic Hydrocarbons</td>
<td>38.7</td>
</tr>
<tr>
<td>Aromatic Hydrocarbons</td>
<td>31.2</td>
</tr>
<tr>
<td>Phenols</td>
<td>7.7</td>
</tr>
<tr>
<td>Neutral Oxygen-Containing Compounds</td>
<td>22.4</td>
</tr>
</tbody>
</table>
TABLE 2
FISCHER ASSAY CHARACTERISTICS OF LYUBAN SHALE OIL

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density, g/cm³</td>
<td>0.88 - 0.91</td>
</tr>
<tr>
<td>Average Molecular Weight</td>
<td>230 - 270</td>
</tr>
<tr>
<td>Heating Value, MJ/kg</td>
<td>41.3 - 41.6</td>
</tr>
<tr>
<td>Ultimate Composition, %</td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>82.9 - 84.5</td>
</tr>
<tr>
<td>H</td>
<td>11.3 - 11.7</td>
</tr>
<tr>
<td>S</td>
<td>1.7 - 2.8</td>
</tr>
<tr>
<td>N</td>
<td>0.7 - 0.8</td>
</tr>
<tr>
<td>O (by Difference)</td>
<td>1.5 - 2.3</td>
</tr>
<tr>
<td>Chemical Group Composition, %</td>
<td></td>
</tr>
<tr>
<td>Non-Aromatic Hydrocarbons</td>
<td>25 - 37</td>
</tr>
<tr>
<td>Mono cyclic Aromatic Hydrocarbons</td>
<td>2 - 5</td>
</tr>
<tr>
<td>Bi- and Polycyclic Aromatic Hydrocarbons</td>
<td>24 - 30</td>
</tr>
<tr>
<td>Phenols</td>
<td>2 - 4</td>
</tr>
<tr>
<td>Neutral Oxygen-Containing Compounds</td>
<td>28 - 41</td>
</tr>
</tbody>
</table>

The Baltic oil shale basin is situated in the Northern part of Estonia, and it extends eastward into Russia, covering a total area over 50,000 square kilometers. The basin has been administratively divided into the Estonia and Leningrad fields, comprising two currently mineable (Estonia and Leningrad) deposits and the prospective Tapa deposit. At present, the Estonia deposit is the largest commercially exploited oil shale deposit in the world with proven reserves of more than 770 million tons of oil shale. The Estonia deposit has been mined continuously since 1916 with an annual output over 20 million tons during the past 2 decades.

The main oil shale (kukersite) sequence is confined to the Viivikonna and Korgekallas formations of Middle Ordovician age (Llandeilo-Early Caradoc). In the central part of the Estonia field, the oil shale-bearing sequence is 20 to 30 meters thick and contains up to 50 individual kukersite beds alternating with argillaceous biomicric limestone beds. The average thickness of these kukersite beds is between 10 and 40 centimeters, but may reach up to 2.4 meters. Individual kukersite beds are either massive or display a nodular structure where kukersite forms a matrix between kerogenous limestone nodules. Detailed lithostratigraphic analysis shows that individual kukersite beds are laterally continuous and can be traced over 250 kilometers in an east/west direction (parallel to the interpreted shoreline). Basinward, however, the organic content in the kukersite beds diminishes rather quickly and beds are no longer distinguishable from the surrounding host limestone after 40 to 50 kilometers.

Kukersite organic matter consists mostly of accumulations of the microfossil *Gloeocapsomonorpha prisca*, which has been considered as an intertidal to shallow subtidal marine, mat-forming cyanobacterium. The organic matter content in individual beds varies greatly, depending mainly on the amount of kerogenous limestone nodules. The most organic-rich beds (B and E) contain up to 50 percent total organic carbon. Semi-quantitative XRD analyses reveal that calcite and dolomite form the main mineral phases in kukersites, while the amount of silt-size clastics (quartz, feldspars and illite) does not usually exceed 15 percent.

The kukersite-type organic matter accumulation in Northern Estonia took place on a stable carbonate ramp in a shallow subtidal to intertidal setting. The accumulation of kukersite-muds also coincided with the most pronounced retreat of the sea in the Northern Baltic area during Ordovician time. Isopach and lithofacies maps of kukersite beds document the lateral persistence of even thin beds over wide areas without any indication of scouring. However, sedimentation was discontinuous as indicated by the presence of numerous mineralized and unmineralized hardgrounds within the oil shale sequence.
The presence of a rich and diverse normal marine bottom fauna in kukersite beds (more than 300 species recorded), together with a low pyrite content, suggests the lack of anoxia in bottom waters. The causes of widespread kukersite kerogen preservation in such a shallow-water oxic environment are still not fully understood and need further studies.

STEAM RETORTING AND COPROCESSING WITH LIGNITE STUDIED FOR TURKISH OIL SHALES

Steam pyrolysis is receiving particular interest due to the oil yield increase, ease of removal of the product, and steam's role as a reagent in shale oil processing. The oil shale/steam contact may be realized in a number of ways, but the most common contacting systems are fixed-bed sweeping and fluidized-bed retorting systems.

These systems were reviewed by E. Ekinci and Y. Yurum at the NATO Advanced Study Institute: Composition, Geochemistry and Conversion of Oil Shales, held in Akcay, Turkey in July 1993. Ekinci and Yurum also discussed the coprocessing of oil shales with lignites.

Fixed-Bed Systems

All fixed-bed pyrolysis systems have limited oil yields. This limitation is due to retrogressive char forming reactions and cracking of volatiles at the hot surface during evolution. In order to overcome mass transfer limitations, which are the main cause of char forming reactions, and to reduce cracking, steam and an inert gas sweep are employed.

The experiments on fixed-bed steam and nitrogen sweep show greater oil yields than Fischer Assay, ranging up to 25 percent greater. The effect of steam on oil yield was found to be greater than nitrogen, which diminished as higher sweep velocities were used.

It has been reported that by increasing sweep velocity, steam and N₂, the yields of alkanes and aromatics increased whereas polars decreased. This effect is more pronounced for steam as compared with nitrogen. These results suggest that alkenes may be involved in retrogressive char forming reactions via dehydrogenation to alkenes and subsequently undergo cyclization.

This may be either because steam promotes bond cleavage reactions and thus creates greater demand for transferable hydrogen, or because steam merely provides a more protective environment, limiting the extent of cyclization and aromatization of the alkanes by passivating the acidic clay minerals. Lower measured concentrations of CO and higher CO₂ concentrations for steam pyrolysis indicate a reaction between CO and steam in the presence of Fe catalyst.

Fluidized-Bed Systems

According to Ekinci and Yurum, some of the more relevant advantages of fluidized-bed processing for oil shale pyrolysis include:

- High thermal efficiency
- High throughput
- Simpler and smaller equipment
- Ease of transportation for continuous mode operations
- High heat transfer rates

The fact that fluidized beds improve the oil yield considerably over fixed beds makes it possible to classify development of many oil shale reserves as economical that would otherwise be classified as uneconomical.

In experiments carried out using a nitrogen sweep fixed bed and a nitrogen fluidized bed, a 9.26 percent production increase was obtained by the latter. This result clearly demonstrates that the type of reactor may cause an important difference in the pyrolysis oil yield. Based on the Fischer Assay, fluidized-bed steam and nitrogen pyrolysis gave 7 to 15 percent more oil, respectively. For United States Eastern oil shales, oil yields from fluidized beds exceeding Fischer Assay yields by 20 to 30 percent were obtained. Fluidized-bed steam retorting gives higher carbon conversion values for gas, oil and shale as compared to nitrogen. The highest fluidized-bed yield for oil shales was reported as 155 to 160 percent in excess of Fischer Assay.

The oils obtained from fluidized beds were different in character as compared to Fischer Assay, report Ekinci and Yurum. The former was more dense, less volatile, more aromatic and higher in nitrogen content.
Similar to fixed-bed sweep experiments, in the fluidized bed oil the amounts of paraffinic and napthenic hydrocarbons and polar compounds increased. Steam oil was found to have slightly higher H/C ratio and lower nitrogen content than did the nitrogen oil. The order of difference was attributed also to the efficiency of the light ends recovery. Otherwise, the oils from steam and nitrogen atmospheres were found to be essentially identical.

Coprocessing of Oil Shales With Lignites

Often Turkish oil shale deposits co-exist in the same sedimentary sequence with lignite. For example, both Goynuk and Seyitomer oil shale reserves overlie lignite deposits. For this reason there are obvious advantages in considering co-utilization of these two fuels.

Mixtures of Goynuk oil shale and Yatagan lignite, and mixtures of Seyitomer oil shale and Seyitomer lignite were coprocessed by using a modified Heinze retort at 550°C under static and nitrogen sweep conditions. The mixtures contained 25, 50 and 75 percent lignite. In contrast to results with Rundle/Stuart oil shale from Australia, higher oil yields of 2 to 5 percent on a dry ash-free basis were found for oil shale/lignite mixtures than for those predicted from non-interacting components.

The highest increase in oil yield was observed for the highest oil shale to lignite ratio. This result was interpreted as due to oil shale partly preventing retrogressive char forming reactions for lignite. The reason for the maximum synergism is further explained in terms of poor compatibility between the shale and lignite. The highly aliphatic shale oils, during the initial stages of pyrolysis in the form of pyrobitumen, are expected to be relatively poor solvents for phenolic lignite materials.

Estonian Energy Economy

About 70 percent of energy demand in Estonia is met by local energy resources, and complementary imported fuels are available as well. The existing generating capacities (technology is mostly obsolete) are underloaded and do not operate economically.

This situation results mainly from the low purchasing power of energy consumers due to the depression in the economy, problems of tax collection and acute lack of investment capital. At the same time the prices received for oil shale and electric energy do not cover the real production cost and provide no way of accumulating funds for improvements or new investment.

The consumption of electricity and oil shale has decreased by 50 percent compared to 1990.

Basic problems to be resolved include development of an energy economy and oil shale industry, price and tax policy, status and structure of energy companies, and energy legislation.

Electricity tariffs and oil shale prices discourage privatization of energy companies.

Proposals and Recommendations

The following proposals and recommendations were made:

- Considering the critical situation in the oil shale production and processing industry, the highest priority must be given to stopping the reduction of production levels. Main principles of a national oil shale policy should be approved by the government.

- The lifetime of the equipment and facilities of oil shale-fired power stations must be evaluated.

- Economic (feasibility) studies for financial (via shares) or administrative integration of oil shale mine, oil shale processing industry and power stations to provide rational use of oil shale reserves and investment funds must be carried out.
- A flexible price regulation and control mechanism must be developed which would take into account inflation, production and investment costs as well as energy tariffs and tax policy.

- The highest priority must be given to the cooperation of the Baltic Sea states, including three Baltic republics.

- A schedule must be developed for the gradual increase of oil shale price and electricity tariffs to the level that would enable minimum required investments, privatization and augmentation of share capital.
ENVIRONMENT

LEACHATE FROM COMBUSTED ISRAELI SHALE COULD BE CLASSIFIED AS HAZARDOUS

Trace elements, plus sulfate, associated with Israeli oil shale were studied by the Geological Survey of Israel, with particular attention to those hazardous substances that are found in leachate from spent bed and cyclone-catch materials. The results of these studies were presented by M. Shirav, at the NATO Advanced Study Institute: Composition, Geochemistry and Conversion of Oil Shales, held in Akcay, Turkey in July of last year.

Trace elements in oil shales from the Rotem deposit, Israel, reside in four major mineral assemblages: Zn, Cu, Ni, V, Cd, Mo, Cr and part of the uranium are associated with the organic matter; Ti, Cr, V, Mn reside mainly in the clay fraction; Cu, Ni, Mn, Zn and As are associated with pyrite; and V, U, Y, Mo, Cr, and Zn are contained in the apatite. The composition of the raw oil shale is basically a marly carbonate with an average of 15 weight percent organic matter content.

The mineralogical composition of the waste material after combustion at approximately 800°C is:
- Calcite, 7 percent
- Anhydrite, 30 percent
- CaO, 4 percent
- Apatite, 4 percent
- Quartz, 2 percent
- Ca$_2$SiO$_4$ plus Ca$_2$AlSiO$_7$, 53 percent

Depending on the residence time of the materials in the boiler, varying amounts of ellestadite (Ca$_5$[(Si,P,S)O$_4$]$_2$)(OH,Cl,F) and 3CaOAl$_2$O$_3$ are formed. There are slight variations in the proportions of the minerals in the spent bed and the cyclone catch due to higher temperatures in the free-board area.

Standard American Society for Testing and Materials and United States Environmental Protection Agency EP batch leaching tests were carried out on spend bed and cyclone-catch materials originating from a fluidized-bed pilot plant combusting Israel oil shale.

Elements released into the leachates as percentages of the original content within the solid wastes were calculated and divided into four groups:
- Less than 0.1 percent: Zn, V, Ni, Cu
- 0.1 to 1 percent: Mn, Cr
- 1 to 5 percent: Cd, As, SO$_4$
- Greater than 5 percent: Mo, Se

These results suggest that the most volatile elements are associated with the anhydrite and are mobilized more easily into the leachates than are all other elements which are incorporated within the newly synthesized silicates, belite and gehlenite. These minerals are known to be thoroughly substituted, with cation replacement in almost all crystal sites.

Although the pH of the leachates is 11.5 to 12.5, the concentrations of arsenic, cadmium, chromium, selenium, molybdenum and sulfate are well above the drinking water standards and even (in the case of some traces) above the recommended irrigation water criteria. However, trace element levels in the leachates do comply with the United States Resource Conservation and Recovery Act standards.

Because the Israeli Ministry of the Environment uses only drinking water standards, the wastes are categorically defined as hazardous materials. Applying hazardous regulations on oil shale wastes could be crucial for the economy of their utilization. Shirav notes, however, that the geographical location of the oil shale operations is an ideal site for hazardous waste disposal. It is remote, with annual rainfall less than 50 millimeters, without any contact with aquifers. It is tectonically stable and could be easily protected from occasional flash floods. Thus, Shirav concludes that although the waste materials of combusted Israeli oil shale are classified as hazardous according to the current standards, the excellent disposal conditions in the area should exempt these wastes from being treated according to hazardous restrictions.

SYNTHETIC FUELS REPORT, MARCH 1994
SODIUM PROSPECTING PERMITS DENIED BECAUSE OF POSSIBLE DAMAGE TO OIL SHALE RESOURCES

On June 8, 1990, Bruce Resources, Ltd. filed two sodium prospecting permit applications for areas of Rio Blanco County, Colorado. On July 26, 1990, H.E. and E.R. McCarthy also filed sodium prospecting permit applications for areas of Rio Blanco County, Colorado. All the requested land lies within the Piceance Creek Basin.

The United States Bureau of Land Management (BLM) rejected the applications in October 1990. In its decision, BLM cited Public Land Order No. 4522, dated September 13, 1968, which withdrew deposits of oil shale and lands containing such deposits from sodium leasing, where oil shale deposits might be adversely affected.

Issuance of sodium prospecting permits in the Piceance Creek Basin would likely lead to sodium leases.

McCarthy and Bruce Resources, Ltd. both appealed BLM's decision to the United States Department of the Interior Office of Hearings and Appeals.

The Office rejected the appeals in November, saying that BLM properly rejected sodium prospecting permit applications for lands withdrawn from sodium leasing (except if it should be found that development of sodium would not adversely affect oil shale values).

###
STATUS OF OIL SHALE PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since December 1993)

ACORN PROJECT — (See Stuart Oil Shale Project)

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

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

Since January 1993, the unit has been operated as a stand-by unit on coal and limestone. It is also available for co-combustion tests if desired.

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

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

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

Chevron is continuing to develop and protect its conditional water rights for use in future shale oil operations at its Clear Creek 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 and a 196-mile pipeline to Lisbon, Utah, was released in December 1975 and the final EIS was later issued. EPA issued a conditional prevention of significant deterioration permit in November 1979. Land exchange was consummated on February 1, 1980. On August 1, 1980, Exxon acquired ARCO's 60 percent interest in the project for approximately $400 million. The preferred pipeline destination was changed to Casper, Wyoming, and the final EIS supplement was completed. Work on Battlement Mesa community commenced summer 1980. The Colorado Mined Land Reclamation permit was approved in October 1980.

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

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

Project Cost: Estimated in excess of $5-$6 billion

SYNTHETIC FUELS REPORT, MARCH 1994
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

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$2.3 billion 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)

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

The Alpha field contains about 90 million barrels of reserves, but the shale in this deposit has a high yield of 88 to 132 gallons of oil per ton of shale.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

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 POWERPLANTS – Estonian Republic (S-80)

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

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

Exploitation of kukersite (Baltic oil shale) resources was begun by the Estonian government in 1918. In 1980, annual production of oil shale in the USSR reached 37 million tons of which 36 million tons come from the Baltic region. Recovered energy from oil shale was equivalent to the energy in 49 million barrels of oil. Most extracted oil shale is used for power production rather than oil recovery. In 1989, annual production of oil shale in the Baltic region was as low as 28 million tons. In 1991, annual production of oil shale in Estonia was 19 million tons. About 10 million tons were extracted from six underground mines and about 9 million tons from three open pit mines. The annual output from the underground mines ranged from 600,000 to 4.3 million tons, while the output from the surface mines ranged from 2.0 to 4.3 million tons. The recovered energy from this oil shale was the energy equivalent of 25 million barrels of oil.

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

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

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

The oil shale retorting industry in Fushun, China began in 1928 and has been operating for 60 years. Annual production of shale oil topped 780,000 tons in 1959. In that period, shale oil accounted for 30-50 percent 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 percent 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 Powerplant 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 powerplant. 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.
COMMERICAL PROJECTS (Continued)

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

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

KIVITER PROCESS - Estonian Republic (S-120)

The majority of oil shale (kukersite) found in Estonia is used for power generation. However, 2.0 to 2.2 million tons are retorted to produce shale oil and gas. The Kiviter process, continuous operating vertical retorts with 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 per day. Retorting is performed in a single retorting (semi-cooking) 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 unit was developed. The first 1,000 ton-per-day (TPD) generator of this type was constructed at Kohtla-Jarve, Estonia 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-cooking chamber. A portion of the heat carrier is prepared by burning recycle gas. Raw shale is fed through a charging device into two semi-cooking chambers arranged in the upper part of the retort. The use of two parallel chambers provides a larger retorting zone without increasing the thickness of the bed. Additional heating or gasification occurs in the mid-part of the retort by introducing hot gases or an oxidizing agent through side combustion chambers equipped with gas burners and recycle gas inlets to control the temperature. Near the bottom of the retort is a cooling zone where the spent shale is cooled by recycle gas and removed from the retort. The outside diameter of the retort is 9.6 meters, and its height is 21 meters. The operation of the 1,000 ton per day generator revealed a problem of carry-over of finely divided solid particles with oil vapors (about 8 to 10 kilograms per ton of shale).

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

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

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

Project Cost: Not disclosed

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

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

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

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

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

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

Mobil has indefinitely deferred development plans for its shale property located on 10,000 acres five miles north of Parachute. The United States Bureau of Land Management completed the Environmental Impact Statement for the project in 1986.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

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

During 1975 a drilling and mining survey revealed 13 oil shale deposits in Morocco, including three major deposits at Timahdit, Tangier, and Tarfaya from which the name T3 for the Moroccan oil shale retorting process was derived.

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

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

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

Project Cost: $2.5 billion (estimated)

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

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

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

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

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

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

Although Congress appropriated $8 million in fiscal year 1991, Occidental declined to proceed with the $225 million "proof-of-concept" modified in situ (MIS) demonstration project to be located on the C-b tract. In January 1991 Occidental announced its intention to shelve the demonstration project in an effort to reduce company debt. The announcement came only a month after the death of Oxy chairman, Armand Hammer, a long-time supporter of oil shale.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

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

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

Project Cost: $225 million for demonstration

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

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

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

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

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

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

PAMA has been developing a Fast-Heating Retorting Process, using hot recycled ash as the heat carrier. Tests have been carried out in a 50 kilogram per hour experimental unit. Work has been started on a 6 ton per hour pilot plant, with startup scheduled for late 1994.

Project Cost: $30 million for combustion demonstration plant

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

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

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

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

In July 1981, the company was awarded a contract under a United States Department of Energy (DOE) program designed to encourage commercial shale 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.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

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 because of failure to consistently reach the financial break-even point. Production ended June 1, 1991 and the project was laid up for an indefinite period.

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

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

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

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

Project Cost: Phase I - Approximately $1.2 billion

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

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

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

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

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

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

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

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

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

| 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 |

SYNTHETIC FUELS REPORT, MARCH 1994
A 36-foot inside diameter retort, called the industrial module, has been constructed at Sao Mateus do Sul. Startup began in January, 1992. Total investment was US$93 million with an annual operating cost estimated to be US$39 million. With the sale of gas to Industria Ceramica do Parana (INCEPA) and anticipated revenue from products, the rate of return on the overall project is estimated to be about 13 percent.

In 1992, the Sao Mateus do Sul project was producing at 80 percent of the full-scale capacity. Total daily production is expected to reach 4,000 barrels of shale oil (at a cost of $22.50 per barrel), 140 metric tons of fuel gas, 50 tons of liquefied petroleum gas and 100 tons of sulfur.

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

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

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

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

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

Project Installed Costs: $120 (US) million

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

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

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

On November 24, 1987, Ramex announced the completion of the Rock Springs pilot project. The formation was heated to approximately 1200 degrees F creating a high-BTU gas with little or no liquid condensate. The wells sustained 75 Mef 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 percent hydrogen, 30 percent 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.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

- 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.

In 1992 Ramex announced a company reorganization and said that new laboratory tests were being arranged to improve its technology.

On September 30, 1993, Ramex Synfuels International, Inc., as sponsor of a private placement of limited partnership interests in Ramex Research Partners, Ltd. successfully closed an offering at the minimum amount intended to be sold of $110,000. As of the end of 1993, Ramex is attempting to obtain additional financing for phase 2, 3 and 4 of the development and testing of the oil shale gasification process.

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

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

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

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

In 1992, Rio Blanco closed its Denver office and moved all activities to the site.

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.
COMMERCIAL PROJECTS (Continued)

The first stage of the project which would produce 5.2 million barrels per year from 25,000 tons per day of shale feed was estimated to cost $645 million (US). The total project (27 million barrels per year from 125,000 tons per day of shale feed) was estimated to cost $2.65 billion (US).

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

- Payment by Esso to SPP/CPM of A$30 million in 1985 and A$12.5 in 1987.
- Each partner to have a 50 percent interest in the project.
- Continuation of a Work Program to progress development of the resource.
- Esso funding all work program expenditures for a maximum of 10 years, and possible funding of SPP/CPM’s share of subsequent development expenditures. If Esso provides disproportionate funding, it would be entitled to additional offtake to cover that funding.

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

Project Cost: US$2.65 billion total estimated

SHC - 3000 RETORTING PROCESS — Estonian Republic (S-230)

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

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

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

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

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

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

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

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

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

By the end of 1991, 1,833,700 tons of shale was processed at SHC-3000 and 220,000 tons of oil had been produced.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

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

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

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

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

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

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

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

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

In the fourth quarter of 1993, the Australian government passed a bill exempting Stuart shale-derived gasoline from paying the normal excise tax, thus giving it a chance to compete on the open market. In December 1992, Stuart Stage 1 received formal government approval as a research and development project, making it eligible for a write-off of 150 percent of 90 percent of capital expenditures (50 percent in each of the first 3 years) plus the same 150 percent write-off for a substantial portion of operating cost for 6 years.

In parallel with these matters, environmental impact studies have been completed and the Stuart partners were granted a mining lease for the term of 24 years in October 1993.

Project Cost: For commercial demonstration module A$110 million

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

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

Oil shale was discovered in the Yaamba Basin in 1978 during the early stages of a regional search for oil shale in buried Tertiary basins northwest of Rockhampton. Exploration since that time has outlined a shale oil resource estimated at more than 4.8 billion barrels in situ extending over an area of 32 square kilometers within the basin.
The oil shales which have a combined aggregate thickness of over 300 meters in places occur in 12 main seams extending through the lower half of a Tertiary sequence which is up to 800 meters thick toward the center of the basin. The oil shales subcrop along the southern and southwestern margins of the basin and dip gently basinward. Several seams of lignite occur in the upper part of the Tertiary sequence above the main oil shale sequences. The Tertiary sediments are covered by approximately 40 meters of unconsolidated sands, gravels, and clays.

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

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

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

KENTORT II PDU—University of Kentucky Center for Applied Energy Research (CAER) (S-290)

CAER has completed a 50-pound per hour Process Development Unit (PDU) in 1993 to test the KENTORT II process. The KENTORT II process is a fully-integrated, four-stage, fluidized-bed oil shale retort. The pyrolysis, gasification and cooling zones are aligned vertically and share a common fluidizing gas. The combustion zone is adjacent to the gasification section, and a separate gas stream (air) is used for fluidization.

Three major shakedown runs were completed during 1993. The 50-pound per hour PDU has been shown to be functional when nitrogen is used for fluidization. To be considered completely operational, however, steam must be used for fluidization. Steam is crucial to the KENTORT II PDU for two reasons. First, steam is a necessary reactant for the gasification zone, and, second, the oil collection system was designed around the use of steam. Shakedown runs using steam for fluidization are planned for early 1994.

CARE researchers hope to achieve yields of 120 percent of Fischer Assay in the fluidized-bed retort when combined with steam sweep.

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

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

In this process, raw shale is rapidly heated in a gravity bed pyrolyzer to produce oil vapor and gas. Residual carbon (char), which remains on the spent shale after oil extraction, is burned in a fluid bed combustor, providing heat for the entire process. The heat is transferred from the combustion process to the retorting process by recycling the hot solid, which is mixed with the raw shale in a fluid bed prior to entering the pyrolyzer. The combined raw and burned shale (at a temperature near 500 degrees C) pass through a moving, packed-bed retort containing vents for quick removal and condensation of product vapors, minimizing losses caused by cracking (chemical breakdown to less valuable species). Leaving the retort, the solid is pneumatically lifted to the top of a cascading-bed burner, where the char is burned during impeded-gravity fall, which raises the temperature to nearly 600 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.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

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

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

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

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

NEW PARAHO ASPHALT OIL PROJECT—New Paraho Corporation (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 were constructed in Colorado, Utah and Wyoming. The test strips are being 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. Test strips were also completed on I-20 east of Pecos, Texas, in Michigan for a test section of I-75 near Flint, on I-70 east of Denver, Colorado and on US-59, northeast of Houston, Texas.

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.

In December 1992 New Paraho announced that its pilot plant in Rifle, Colorado was currently producing 15 barrels of shale oil daily as part of a new SOMAT test marketing program started in September.

The first phase of the new test market program for SOMAT is expected to cost $1.2 million through 1993, produce enough SOMAT for 50 to 60 miles of asphalt roads and employ 15 people.

SYNTHETIC FUELS REPORT, MARCH 1994
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

The test strip results have been encouraging and SOMAT is proving to be a superior road paving material, with distinct life-cycle cost advantages.

The oil shale asphalt, as a 10 percent additive to conventional asphalt, is far more resistant to water damage and aging than conventional asphalt. It adds about 10 to 15 percent to the cost of asphalt, but is a bargain compared to other asphalt modifiers that accomplish the same tasks and increase costs by 30 to 35 percent.

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.

Project Cost: $3,700,000

YUGOSLAVIA COMBINED UNDERGROUND COAL GASIFICATION AND MODIFIED IN SITU OIL SHALE RETORT — United Nations (S-335)

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

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

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

Project Cost: US$725,000
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PROJECT ACTIVITIES

OIL SANDS PRODUCTION FIGURES UPDATED

Statistics published by the Alberta Energy Resources Conservation Board (ERCB) show that, after hitting monthly production levels of 386,000 cubic meters in August last year, Suncor’s synthetic crude oil production dropped to 311,000 cubic meters last October, and dropped further to 281,000 cubic meters in December (Figure 1).

Synthetic crude oil production at Syncrude Canada Ltd. continues to fluctuate as illustrated in Figure 2 (next page). Last October, Syncrude again topped the 1 million cubic meter mark, then lost ground in November, when 941,000 cubic meters of synthetic crude oil were produced. Total fourth-quarter production was 2,863,000 cubic meters, a new record for the quarter.

For the year as a whole, Syncrude produced a record volume of more than 67 million barrels of light, sweet, synthetic crude from its Athabasca oil sands during 1993, surpassing the previous mark of 65.4 million barrels in 1992.

IMPERIAL OIL DEFERS PHASES 9 AND 10 AT COLD LAKE

Imperial Oil Ltd. has further deferred the next two planned expansions of its Cold Lake heavy oil project in Northeastern Alberta because of the sharp drop in global oil prices.

---

FIGURE 1

SUNCOR SYNTHETIC CRUDE OIL PRODUCTION 1990–1993

SOURCE: ERCB
Imperial will spend no additional money on Phases 9 and 10 at Cold Lake.

Imperial's Cold Lake project involves drilling a series of shallow wells and pumping steam into the wells to heat the heavy oil, forcing it into an adjacent processing plant.

Phases 9 and 10 of the project would have boosted production from 100,000 barrels per day to 125,000 barrels per day.

SHELL CANADA TESTING SAGD PROCESS AT PEACE RIVER

Shell Canada Limited announced in November that it has introduced Enhanced Steam-Assisted Gravity Drainage (ESAGD) technology at its Peace River facility.

The company began the first application of ESAGD, which involves injecting steam into the earth to create a steam chamber beneath the surface. Bitumen then flows down to a producing well.

The $11 million horizontal well project relies on gravity to drain heated bitumen from the surface of an underground steam chamber into the two production wells, by first injecting steam into the cavity through two injection wells.

Shell planned on injecting steam for 2 months and anticipated oil production from the pair of wells sometime early in 1994. Production was expected to be about 1,000 barrels per day.

If the test is successful, Shell will consider applying the technology to begin a staged development of the rest
of its Peace River area holdings. The company holds leases on 150,000 acres, containing an estimated 14 billion barrels of bitumen. Production at Peace River has been 10,000 barrels of bitumen per day.

###
CANADIANS TO POOL RESOURCES FOR OIL SANDS R&D

The Canadian Oil Sands Network for Research and Development (CONRAD) has been formed pursuant to a proposal made in June (see the Pace Synthetic Fuels Report, September 1993, page 3-12).

The goals of CONRAD are tapping the full potential of the oil sands and heavy oil of Alberta and Saskatchewan and making that resource more competitive in the global market. The consortium includes six major oil companies, five research groups, two universities and the governments of Alberta and Canada.

CONRAD will lead collaborative research aimed at improving the competitiveness of the oil sands industry through development of superior technology. Members of CONRAD currently spend more than $100 million annually on oil sands and heavy oil research and development projects. CONRAD will direct about one-third of that sum toward collaborative research.

Oil production from oil sands and heavy oil now accounts for more than 30 percent of total Canadian output. CONRAD aims to increase that amount to as much as 50 percent with the next 15 years.

The consortium aims to develop technology that will improve the industry's competitiveness and environmental performance, while reducing production costs to well below C$15 per barrel by 2002.

CONRAD will be structured around four research portfolios:
- Environmental
- In situ
- Mining and extraction
- Upgrading

CONRAD is composed of Alberta Environmental Centre, Alberta Oil Sands Technology and Research Authority, Alberta Research Council, Amoco Petroleum Company Ltd., Canada Centre for Mineral and Energy Technology, Chevron Canada Ltd., Imperial Oil Limited, National Research Council, Shell Canada Ltd., Suncor Inc. Oil Sands Group, Syncrude Canada Ltd., University of Alberta, and University of Calgary.

####
GOVERNMENT

OIL SANDS ORDERS AND APPROVALS LISTED

The recent orders and approvals in the oil sands areas issued by Alberta, Canada's Energy Resource Conservation Board are listed in Table 1 (see next page).

####

SYNTHETIC FUELS REPORT, MARCH 1994
## TABLE 1

### SUMMARY OF OIL SANDS ORDERS AND APPROVALS

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Some recent patents issued by the United States Patent Office in the field of oil sands technology are listed in the following.

**Pipeline Conditioning Process for Mined Oil Sand**

U.S. Patent No. 5,264,118 issued to George J. Cymerman, et al., and assigned to Alberta Energy Company, Ltd., et al., utilizes a pipeline. As-mined, naturally water-wet oil sand is mixed at the mine site with hot water and NaOH to produce a slurry containing entrained air. The slurry is pumped through a pipeline and is fed directly to a conventional gravity separation vessel. The pipeline is of sufficient length that coalescence and aeration of bitumen occurs so that, when subsequently retained in the gravity separation vessel under quiescent conditions, a viable amount of the bitumen floats, forms froth, and is recovered.

**Process for Separation of Hydrocarbon From Tar Sands Froth**

U.S. Patent No. 5,236,577 has been issued to Bruce M. Sankey and Robert N. Tipman and assigned to OSLO Alberta Ltd. A process for treating bitumen froth containing mixtures of a hydrocarbon component, water and solids, comprises heating the bitumen froth to a temperature in the range of about 100°C to 180°C, under pressure of about 800 kPa to about 2,000 kPa, sufficient to maintain the hydrocarbon component in a liquid phase. Next the heated froth is passed into a plurality of separation stages in series, and gravity settling separates the solids and water from the hydrocarbon layer. A diluent miscible with the bitumen may be mixed with the bitumen froth in an amount about 15 to 50 percent by weight of the bitumen in a mixing stage for preconditioning of the froth prior to each gravity separation stage. A low molecular weight hydrocarbon diluent, such as typified by naphtha, kerosene, toluene or natural gas condensate, is preferred.

**Process for Increasing the Bitumen Content of Oil Sands Froth**

U.S. Patent No. 5,223,148 issued to Varagur S. Rajan, et al., and assigned to OSLO Alberta Ltd. involves a process and an apparatus for separation of water and solids from oil sands froth in which heated froth is fed into a gravity settling vessel at a level below a bitumen-water interface established between a bitumen froth layer and a quiescent body of water on which the bitumen froth floats. Water and solids contained in the froth separate from the froth stream, the oil rises to accumulate in the bitumen froth layer, and the solids fall by gravity to the bottom of the gravity settling vessel.

The apparatus comprises an injector manifold bitumen-water interface, said injector manifold having several inwardly facing openings for the inward discharge of oil sands froth into the body of water. The injector ring manifold may also have several outwardly facing openings for both inward and outward, discharge of froth. A level probe monitors the level of the bitumen-water interface and communicates with a valve for discharging underflow.

**Method and Apparatus for Improved Recovery of Oil From Porous, Subsurface Deposits**

John A. Masek has received U.S. Patent No. 5,217,076. A method and apparatus for the improved recovery of oil from tar sands comprises mining and drilling a well with upper and lower horizontal rectangular grids extending outward into the deposit and then applying steam heat or superheated crude oil vapor through the lower grid and hot pressurized flue gas through the upper grid. The flue gas and steam or superheated crude oil vapor are produced in a generation facility that provides electricity for the installation. The crude oil for superheating is provided by an initial production from the deposit following flue gas injection. Steam condensate is recycled from the recovered oil to the generation facility thereby reducing the water requirements and environmental pollution, and, where superheated crude oil vapor is used, a portion of the produced crude is used for this purpose.
Process for Separating Bitumen From Tar Sands

U.S. Patent No. 5,186,820 issued to G. Daniel Irvin and Clifford W. Schultz and assigned to the University of Alabama is a process for separating bitumen from tar sands, which comprises: a) agitating a mixture of tar sand with substantially coarse clean sand at ambient or below ambient temperature in the presence of water, so as to mechanically shear bitumen and enhance the detachment of bitumen particles from mineral matter in said tar sand; b) eluting the detached bitumen and fine mineral matter from the coarse sand by an upward flow of water while stirring gently; c) returning the coarse sand to Step A for reuse; and d) subjecting the eluted bitumen and fine mineral matter to froth flotation to separate the bitumen from said fine mineral matter, wherein the flotation is effected without using any reagents.

Recovery of Petroleum From Tar Sands

Basil S. Fee and Richard R. Klimpel have received U.S. Patent No. 5,169,518, assigned to The Dow Chemical Company. The patent claims that the recovery of bitumen from tar sands by flotation is improved by the use of alkanol amines as flotation promoters. Monoethanolamine and diethanolamine are particularly useful for this purpose.

Method for Improving Heavy Crude Oils by Reducing the Asphaltene Content of Crude Oils and Oil-Containing Tar Sands

U.S. Patent No. 5,152,886 has been issued to Lucinda C. Paris-Marcano and assigned to Laboratorios Paris. It is a process for reducing asphaltene content of crude oil and oil-containing materials to improve rheological properties of crude oils and enhance the water-extractabilities of sulfur and metals contained in them. The process employs the cold cracking effect of a binary acid solution containing, preferably, hydrochloric acid and oleic acid. The process is particularly applicable to the exploitation of heavy and ultra-heavy oil deposits, to oil recovery from oil-containing tar sand, shale or clay and to the cleaning of oil tanks, garments and clogged oil pipelines.

Single Horizontal Wellbore Process/Apparatus for the In Situ Extraction of Viscous Oil by Gravity Action Using Steam Plus Solvent Vapor

J. Michael Sanchez has been granted U.S. Patent No. 5,148,869, assigned to Mobil Corporation. It describes a conduction heating, gravity assisted, single well, process for removing viscous hydrocarbonaceous fluids from a reservoir penetrated by a horizontal wellbore. Steam and a gas soluble in hydrocarbon fluids are circulated into the wellbore at or below the reservoir pressure through an upper perforated conduit of the horizontal wellbore. Circulation is continued so as to allow steam to heat the reservoir by conductance while gas enters the hydrocarbonaceous fluids. Thus, heated hydrocarbonaceous fluids having a reduced viscosity flow from the reservoir around the horizontal wellbore where the fluids are produced to the surface by a lower conduit within the horizontal wellbore. The lower conduit is open along its length so as to be in fluid communication with the reservoir for the length of the horizontal wellbore.

###

IN SITU COMBUSTION IN CANADIAN HEAVY OIL RESERVOIRS REVIEWED

Field in situ combustion projects are traditionally designed using air and fuel requirements as determined from laboratory combustion tube tests. While these parameters are important, the observed stability of the combustion process in the laboratory at the operating pressures of the field project is of greater significance in predicting field performance. Tests conducted at field pressures tend to give a better indication of the state of the oxidation reactions as they are operating in the field project.

The laboratory combustion performance of different heavy oil and oil sand reservoirs was reviewed by R.G. Moore, et al., of the University of Calgary, in a paper presented at the 1993 Eastern Oil Shale Symposium, held in Lexington, Kentucky in November.

The field performance of some of the approximately 30 in situ combustion projects which have been or continue to be operated in Canada was also discussed.

In Situ Combustion Projects in Canada

The first Canadian in situ combustion project described in the open literature occurred in 1920, when combustion was attempted in the Athabasca reservoir near Fort McMurray, Canada. This was followed in 1958 by Amoco’s fireflood at Gregoire Lake, which was also located in the Athabasca deposit. Ap-
proximately 30 combustion projects have been conducted in Canada since that time, all in Alberta and Saskatchewan.

Based on longevity and the number of wells involved, Mobil's Battrum project in Southwestern Saskatchewan must be considered the most successful combustion project in Canada. Another success is PanCanadian's Countess "B" combustion project, which was initiated as dry combustion in 1982 but has recently been switched to the wet mode. The Battrum and Countess "B" firefloods, as well as the Fosterton Northwest pilot (operated by Mobil from 1970 until 1989), involved the highest gravity oils in which combustion has been successful in Canada.

A large number of Canadian combustion projects have been operated in what are loosely classified as Lloydminster-type sands. Husky has been the most active company. One characteristic of the Husky firefloods was the observation of an apparent upper limit for the air injection rate.

Norcen operated a successful fireflood pilot at Bodo, but attempts to operate the process on an expanded basis were generally ineffective. Part of the reservoir under the expanded pilot was underlain by water, which may have promoted the difficulties with the Bodo expansion. Problems due to bottom water were also experienced at the Murphy Eyehill and the Alberta Energy Suffield projects.

The Petro-Canada project in the Viking Kinsella Wainwright "B" pool operated in two phases: first air, followed by oxygen injection. The first phase was successful, but the combustion zone kinetics then appeared to switch from the high- to the low-temperature mode when the air rate was decreased in preparation for oxygen injection. The switch to pure oxygen injection was not successful at reversing the kinetics, and the oxygen phase was terminated due to excessive oxygen concentrations in the production wells.

Only one fireflood project continues to operate in the Lloydminster area. This is the Morgan pilot operated by Amoco Canada.

BP Resources Canada operated a successful in situ combustion project at Marguerite Lake in the Cold Lake deposit. The reservoir was first preheated using steam to establish communication between the injectors and producers, then both air and oxygen injection were evaluated. Continuous air/oxygen injection was not utilized; instead, BP developed a cyclic method known as the "Pressure Up Blow Down" process.

While BP was the first, and the most successful, operator to test oxygen injection in Canada, oxygen pilots were also conducted by Dome Canada at Lindbergh, by Husky at Golden Lake Waseca, by Gulf Canada Resources at Pelican Lake in the Wabasca Oil Sands, and by Petro-Canada at the Kinsella "B" pilot. In general, none of these pilots could be considered technical successes, although each proved that it is possible to safely inject oxygen in an oil field environment. Oxygen breakthrough to the production wells was a major problem for all of these projects.

Combustion Tube Tests on Canadian Reservoirs

The air and fuel requirements needed for the design of field projects are generally evaluated by means of laboratory combustion tube tests. These tests are often performed under high injection air fluxes and with the outlet end of the core open to the atmosphere; under these favorable conditions, they tend to operate in the classical high-temperature combustion mode. It has been the experience of the University of Calgary In Situ Combustion Research Group that, when field conditions (in terms of operating pressures and air fluxes) are duplicated in the laboratory, abnormal burning behavior often results. Abnormal behavior is defined here as poor burning performance as evidenced by high air or oxygen and fuel requirements and low oil production, or by burn instabilities such as the non-uniform advancement of oxidation or combustion fronts.

Some problems that have been observed in the laboratory are as follows:

- Lack of oil mobility in the region downstream of the elevated-temperature zone
- Formation of plugs due to high initial oil saturation
- Tendency in the Countess "B" superwet for the trailing edge, or vaporization front, to stall

Comparison of Laboratory and Field Performance for Canadian Oils

The Canadian firefloods which were operated in the Athabasca, Cold Lake, Wabasca and Lindbergh reser-
voirs confirmed the role of oil mobility in the success of an in situ combustion process. Amoco showed that operating on small pattern sizes also contributes to the successful burning of an Athabasca reservoir. Steam preheating followed by fireflooding was found by BP to be an effective recovery process for the Cold Lake reservoir; they also determined that it was advantageous to modify the combustion process from that of continuous to cyclic air or oxygen injection. Failure of the combustion projects in the Wabasca and Lindbergh reservoirs can almost certainly be attributed to the combination of large pattern sizes and the lack of any heated communication paths within the reservoir, say Moore, et al.

All of these observations are consistent with what would be expected from laboratory observations. Essentially all of the problems reported for the above bitumen and heavy oil reservoirs can be related to restricted gas fluxes in the oil bank region. As would be predicted from laboratory experiments, the injection of pure oxygen is not a way to overcome the mobility problem, and it will almost surely result in the kinetics operating in the low-temperature mode where the gas mobility is limited.

The mixed success of the firefloods operated in the Lloydminster-type reservoirs illustrates the problems of operating the process in relatively-thin heavy oil reservoirs. Many of the operating problems reported for the Lloydminster reservoirs suggest that the combustion projects were operating in the low-temperature mode.

Once the kinetics have been allowed to drop into the low-temperature mode, it is difficult to return them to the proper high-temperature regime. For Canadian oils, ignitions which do not result in the development of a high-temperature combustion region will almost certainly suffer poor burning characteristics unless other steps are taken to rectify the low-temperature condition.

The switch from high-temperature combustion reactions (which generate carbon dioxide) to a low-temperature oxidation mode (which generates liquid- and solid-phase oxidation products) will result in a significant decline in the oil mobilization efficiency. This condition will be marked by the rapid breakthrough of combustion gas to the production wells. Because oil is not being effectively mobilized by the oxidation zone, the oil and gas production characteristics will suggest that the production wells are gas locked.

The performance of the oxygen-injection phase of the Kinsella "B" project confirmed that oxygen injection should not be viewed as an automatic method for improving combustion efficiency. This does not imply that oxygen injection should not be considered, but only that it may be necessary to adapt the process using procedures such as those developed by BP at their Marguerite Lake project.

In general, combustion projects such as Murphy Eyehill, Norcen Bodo and the Alberta Energy Suffield project, which were underlain by water, exhibited difficult operating problems. Although it may be thought that the pattern sizes at Eyehill and Bodo were too large in view of the bottom water, this should not have been the case at Suffield. The Suffield project, like the Pan Canadian Countess "B" project, had high initial operating pressures and air injection pressures. The operating pressures associated with these projects promoted operation in the low-temperature regime. The combination of the reservoir properties (high initial saturation of a relatively viscous oil in a consolidated formation with bottom water) and the operating pressure would have almost surely driven the oxidation reactions into the low-temperature mode.

Analysis of the Countess "B" reservoir would suggest that this project is operating in a low-temperature mode. This behavior is consistent with the behavior observed in the laboratory.

The success of the Mobil Battrum fireflood shows that combustion can succeed in Canadian reservoirs. This project has demonstrated that it is possible to operate on large spacings, but it should not be overlooked that Mobil utilized much higher air injection rates than is usually noted in the literature during the early life of the project.

**Future of Combustion in Canada**

Moore, et al., conclude that given the good agreement between field behavior and what might be expected based on laboratory experience, field operating procedures can be developed to realize the theoretical advantages of the combustion process. It must be recognized that firefloods do not always operate in the high-temperature mode, but rather that they can operate in a regime which does not provide for efficient recovery of the contacted oil.

Moore, et al., suggest the application of wet combustion and cyclic combustion, as the application of both
techniques has been shown to be effective in both the field and the laboratory. The incorporation of horizontal wells into combustion projects also has great potential. Given the strong effect which many firefloods have on the offset wells, it would appear that fireflood patterns should not be contiguous and that they should be operated so as to maximize oil production from the combined combustion and offset wells. Under this scenario, it would be desirable to locate horizontal wells adjacent to the combustion patterns. The pattern under combustion would then be viewed as an energy generation region, and it would have to be operated so as to maximize the benefits on the offset horizontal wells.

###

SUPERCRITICAL FLUID EXTRACTION OF OIL SAND BITUMEN STUDIED

Supercritical Fluid Extraction (SFE) is normally carried out at or above the critical pressure ($P_c$) and critical temperature ($T_c$) of the solvent. SFE has found numerous applications in the food and petroleum processing industries. Chevron is reportedly using propane for in situ recovery of oil sand bitumen from one of their Canadian reservoirs on a pilot scale.

The objectives of a study carried out at the University of Utah on SFE of PR Spring bitumen (Utah oil sands) with propane, included the following:

- Determination of the effects of pressure and temperature on extract yields and on the composition of the extract phases
- Determination of the chemical composition of the residual fractions
- Determination of the extent of asphaltene rejection during SFE

This work was reported by M. Subramanian, et al., of the University of Utah, in a paper presented at the 1993 Eastern Oil Shale Symposium, held in Lexington, Kentucky in November.

**Experimental Results**

Bitumen extractions were carried out at five different operating conditions using propane as the solvent. Three different pressure and temperature combinations resulted in four conditions in the critical region and one with $P_r > 1.0$ and $T_r < 1.0$.

The extraction performance is defined as the cumulative weight percent of bitumen extracted. The extraction performance of propane at three different reduced pressures and at a constant reduced temperature of 1.03 is compared in Figure 1. The highest extraction yield, 38.4 weight percent, was achieved at $P_r = 3.8$ compared to yields of 20.8 weight percent and 8.8 weight percent at $P_r = 2.3$ and 1.2, respectively. The increase in extraction yield at higher extraction pressures was directly related to increased solvent density at higher pressures.

The extraction yield at three different reduced temperatures and at a constant reduced pressure of 2.3 are compared in Figure 2. An extraction yield of 38.8 weight percent was achieved at $T_r = 0.92$, and yields of 20.8 weight percent and 15.7 weight percent were obtained at reduced temperatures of 1.03 and 1.14, respectively. This decline in extraction yields with an increase in temperature can be attributed to a decrease in solvent densities at higher temperatures. The extraction yield for propane with PR Spring bitumen increased with solvent density as shown in Figure 3 (page 3-14).

High temperature simulated distillation analyses were carried out on all extract and residual fractions.

The residual fractions produced in the SFE of the PR Spring bitumen were fractionated into asphaltenes (pentane insolubles), saturates and aromatics, and resins.

The absolute asphaltene content of the residual fractions was higher than the asphaltene content of the original bitumen. Subramanian, et al., concluded that compounds which did not precipitate as pentane insolubles from the original bitumen were precipitating from the residual fractions. The asphaltene content of the residual fractions increased with increased extraction yields.
The H/C atomic ratio for the residual fractions decreased with an increase in extraction pressure at constant temperature and also increased with an increase in temperature at constant pressure. The H/C atomic ratios in the residual fractions were lower than that of the original bitumen, indicating that saturated compounds were preferentially extracted, leaving the residual portion more polar and relatively richer in unsaturated compounds.

Modeling of the SFE process was carried out in order to predict the phase behavior during extraction.

The experimental and calculated extract phase composition for PR Spring bitumen-propane extraction at a $P_r$ of 2.3 and a $T_r$ of 0.92 was compared. The highest propane density studied was obtained at these conditions and gave the closest match between the experimental and predicted values.

**Conclusions**

The authors draw the following conclusions from their investigations:

- Pure solvent density was the governing factor for the extraction of PR Spring bitumen with propane. The extraction yield increased with an increase in pure solvent density.

- The asphaltene content of the residual fractions was higher than the original bitumen on an absolute basis assuming all the asphaltene stayed in the residue. This indicates the depletion of cosolubilizing agents during the extraction process.

- The H/C ratio of the residual fractions was lower than the original bitumen, thus estab-
lishing that saturated hydrocarbons were preferentially extracted, leaving the residue richer in unsaturated compounds.

- Reasonable agreement between the experimental and predicted phase compositions was observed at the highest solvent density.

###

STEAM-ASSISTED GRAVITY DRAINAGE BECOMING PROVEN TECHNOLOGY FOR OIL SANDS AND HEAVY OIL

In the Steam-Assisted Gravity Drainage (SAGD) process, heated oil drains from around growing steam chambers, driven by gravity, to horizontal wells below. Advantages of SAGD are as follows:

- The displacement of the oil is systematic and high recoveries can be obtained.

- In suitable applications, oil to steam ratios higher than those found for conventional steamflooding can be achieved.

- The process can be used in even the heaviest of bitumen reservoirs without extensive preheating. This is possible because once the oil is heated, it remains hot as it drains to the production well; this is unlike conventional steamflooding, in which oil cools on its way to production.

Because horizontal wells (potentially long) are used, they have much greater contact with the reservoir than do conventional wells and adequate flows can be achieved with heads equivalent to that obtained from gravity; this is not possible with vertical wells.
SAGD allows steamflooding at economic rates without the bypass of steam. It gives high recoveries in both bitumen and heavy oil reservoirs. It has been demonstrated in Canadian field trials with results which are in reasonable agreement with prior theoretical and scaled model studies.

The development of the SAGD process is reviewed in an article by R.M. Butler, of the University of Calgary, published in The Journal of Canadian Petroleum Technology, February 1994.

SAGD Concept

Figure 1 shows the SAGD process in a fairly early phase. Steam is injected from a horizontal well or one or more vertical wells somewhat above the horizontal producer. A steam saturated zone is formed in which the temperature is essentially that of the injected steam. The steam flows to the perimeter of the steam chamber and condenses. The heat from the steam is transferred by thermal conduction into the surrounding reservoir. The water condensate from the steam and the heated oil flow, driven by gravity, to the production well below. As the oil flows away and is produced, the steam chamber expands.

The growth upwards proceeds in a rather irregular, but quite rapid, manner until it is limited by the top of the reservoir.

In contrast, the interface moves sideways and downward in a stable manner; it is stabilized by gravity.

At a later stage in the process the chamber reaches the top of the reservoir and spreads sideways beneath the overburden, according to Butler. If product is removed too quickly from the horizontal production well, then the steam chamber will be drawn down to the well and bypassing of steam will occur. Essentially the only drive available to move oil to the vicinity of the well comes from the effect of gravity, and the
FIGURE 1

STEAM-ASSISTED GRAVITY DRAINAGE PROCESS

Mechanism:
- Steam condenses at interface
- Oil and condensate drain to well at bottom
- Flow is caused by gravity
- Chamber grows upwards and sideways

Continuous steam injection into chamber
Oil and condensate drain continuously

Steam flows to interface and condenses
Heated oil flows to well

SOURCE: BUTLER

mobile oil is that which is relatively close to the steam chamber. The process is ineffective with vertical production wells because of the relatively low flows that can be achieved under these conditions. However, with long horizontal wells, economic flows can be achieved. For example, in conventional reservoirs, a 1,000 meter horizontal well on a 4 hectare spacing has a productivity index which is about 100 times that of a conventional well.

SAGD Production of Bitumen

A significant problem in the application of SAGD to the production of bitumen is establishing the initial communication between the injection and production wells. This is necessary so that condensate from the steam can be removed and allow further steam to flow into the reservoir and continue heating, says Butler.

A method of accomplishing this is to use an injection well that is above but close to the production well. The intervening bitumen can be mobilized by heating both the injection and production wells and by applying a pressure difference between them. A horizontal injection well can be used, which has the advantage of providing steam over the entire length rapidly. Vertical injectors have also been used, but many vertical injection wells are required to give the same performance as a single horizontal injector if a long horizontal production well is to be used.

If the approach of using closely spaced injectors and producers is employed for the production of bitumen, then the process starts with the steam chamber rising through the reservoir to the overburden. This occurs relatively rapidly, at rates on the order of 0.1 meter per day. Following the rise of the steam chamber to the top of the reservoir, there is a spreading and then a depletion phase. The production rate increases quite rapidly during the chamber rise period, reaches a maximum and then declines as the process proceeds.

A comparison of cumulative production for different well spacings shows that for higher well spacings, the production continues longer. The main advantage of closer well spacing is that the oil/steam ratio is better because of the shorter time which is necessary to keep the reservoir hot. On the other hand, close well spacing involves a higher cost for constructing the wells and, as a result, there is an economic optimum. The oil/steam ratio can be predicted, and computer programs are available.

Butler reports that SAGD has been successfully demonstrated by Esso in the Cold Lake reservoir (oil viscosity in situ about 100,000 mPa.s) using horizontal wells drilled from the surface and by AOSTRA (Alberta Oil Sands Technology and Research Authority) at its Underground Test Facility (UTF) in the Athabasca sands (about 1,000,000 mPa.s).

The original Esso pilot well, with a horizontal length of about 150 meters, has produced 330,000 barrels of bitumen in 10 years with a cumulative oil/steam ratio of 0.38. Production rates of over 500 barrels per day with oil/steam ratios of over 0.35 should be possible in Cold Lake with the use of 500-meter production and injection wells.

Scale-model experiments and theory indicate that projects like the AOSTRA UTF, with 20- to 25-meter well spacings, should be able to achieve recoveries of over 50 percent with a project life of about 2 to 3 years and a cumulative oil/steam ratio of about 0.4. Larger spacings are probably more economic in most circumstances, e.g., 75-meter spacing would extend
project life by a factor of about 3. Production rates of over 300 barrels per day should be possible with 500-meter wells.

**Production of Conventional Heavy Oil**

Conventional heavy oil can be produced by SAGD with the injection well near to the top of the reservoir which also has a bottom water layer. The conditions are adjusted to make the production well pressure nearly equal to that of the aquifer so as to control water production.

During the first phase of this type of operation, the steam chamber moves downward and cold oil and condensate from the steam are displaced to the production well. The rate at which this process occurs and the quantity of oil which is recovered can be estimated. Once the steam zone reaches the vicinity of the production well, the production temperature increases and the normal SAGD process can be carried out. This concept has been tested in a series of scale-model experiments.

Experiments showed that good recoveries could be obtained with little heat loss to the underlying water. It was also shown that excellent operation could be obtained even if the production well were below the initial water/oil contact. In this circumstance, water was displaced from around the production well by oil in the initial stages of the experiment.

A promising pilot project has been operated since 1988 by Sceptre Resources in the Tangleflags reservoir (oil viscosity about 6,000 mPa.s) near Lloydminster, Saskatchewan, Canada; production rates of over 1,000 barrels per day have been obtained. A second well that was drilled in 1990 gives equivalent production.
INTERNATIONAL

INTEVEP PLANS HEAVY CRUDE PROCESSING PLANT

According to a report in OPEC Bulletin, Intevep, a research affiliate of Petroleos de Venezuela (PDVSA) plans to build a heavy crude processing plant that will use a technology known as HDH.

Intevep developed the HDH technology to handle Venezuela's extra-heavy crudes and refinery residuals.

The plant reportedly will be constructed at the Maraven-operated Cardon refinery on the Paraguana Peninsula. Construction should begin in 1994 with production of about 15,000 barrels per day to start in 1997.

A second plant may be built later for Corpoven, another PDVSA subsidiary, which is involved in developing the heavy crudes in the Orinoco oil belt in Eastern Venezuela.

Corpoven is seeking partners for the construction and operation of such a plant through a strategic association. They reportedly hope to bring it onstream by the year 2000.

ORIMULSION PICKS UP SUPPORT IN EUROPE AND CANADA

The Commission of the European Union (formerly the European Community) reportedly has given support for Venezuela's position in a disagreement with the United Kingdom over the classification of Orimulsion for customs and excise purposes.

The United Kingdom contends that the fuel should be classified as a petroleum-based substance and, as such, should be subject to tax.

Venezuela maintains that Orimulsion, a water-based emulsion of bitumen obtained from the Orinoco reserves, belongs in the same chemical and tax-exempt category as coal and lignite.

The European Union Commission's Directorate responsible for indirect taxation was expected to present a draft directive on the reclassification of a number of products, including Orimulsion, before the end of 1993.

In August, pollution authorities in the United Kingdom gave permission for two electricity power stations to import Orimulsion, in the face of considerable opposition from environmental groups.

Meanwhile, a Canadian electricity generator, New Brunswick Power, is satisfied with the environmental aspect of its Orimulsion testing.

Construction of the 312 megawatt Dalhousie station was started in February 1992. Conversion from coal to Orimulsion was part of the project and building work is expected to be completed in September 1994.

Orimulsion will be delivered from Venezuela by two vessels, each carrying 40,000 tons of the fuel. The generating station is equipped with five storage areas for the fuel, with a combined capacity of 175,000 tons. The plant is expected to burn about 64,000 tons of Orimulsion each month.

###
HEAVY OIL POTENTIAL IN ALASKA STUDIED

The objectives of a nationwide study of heavy oil feasibility in the United States are to:

- Investigate from publicly available data the known heavy oil resources
- Screen this resource for potential thermal or other enhanced oil recovery techniques
- Evaluate various economic facets that may have an impact on the expansion of heavy oil production (refining, transportation, environmental, etc.)

A study of the feasibility of heavy oil recovery—production, marketing, transportation, and refining—in Alaska has been completed. This report was summarized by D.K. Olsen, et al., in a United States Department of Energy Progress Review published in December 1993. Relevant public domain information was compiled, analyzed, and presented.

The term "heavy oil" as used in this study is oil of 10 to 20°API inclusive at 60°F with a gas-free viscosity of 100 to 10,000 centipoise inclusive at original reservoir temperature. This portion of the study was undertaken because previous studies have indicated the existence of a significant heavy oil resource in Alaska of 5 to 35 billion barrels. There is a growing concern with the decline (Figure 1) in Alaskan North Slope (ANS) crude oil production. As of October 1992, the production was 1.705 million barrels per day of 27°API gravity crude. ANS contributes 24 percent of the total United States production. The Prudhoe Bay oil field has been in decline since May 1989.

Alaska produces heavy oil from Milne Point field, but the volume is small (less than 0.1 percent of total ANS daily oil production during the spring of 1992). However, this primary production is anticipated to increase based on the projected number of wells to be drilled in the field. Alaska is believed to have huge heavy oil deposits (Figure 2), which at one time were thought to be as much as 35 billion barrels, of which 15 to 25 billion barrels were speculated to exist in the West Sak and 11 to 19 billion barrels in Ugnu.

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FIGURE 1

RECENT AND PROJECTED PRODUCTION FROM NORTH SLOPE OF ALASKA

SOURCE: OLSEN, ET AL.

SYNTHETIC FUELS REPORT, MARCH 1994

3-18
FIGURE 2
TOTAL ESTIMATED OIL IN PLACE IN THE NORTH SLOPE OF ALASKA (With API Gravity and Proposed Recovery Factors)

SOURCE: OLSEN, ET AL.

ARCO's initial target was 25 to 30 percent recovery of their estimate of 5 to 11 billion barrels of oil in place in the West Sak sands using thermal methods. The heavy oil overlying Ugnu reservoir was estimated by ARCO to be 6 to 11 billion barrels. On the basis of further exploration and drilling in the last few years, these estimates have been reduced to 5 billion barrels. Because of the expected low recovery factor, the recoverable oil is currently estimated to be only 423 million barrels in the West Sak, the most viable large heavy oil reservoir. The factors critical to the development of these resources are world oil prices, governmental policies, environmental constraints, availability of a transportation system to deliver the produced heavy oil to a suitable refinery, availability of capital, and rate of return on investment.

Significant heavy oil exists in Alaska and is being produced in limited volumes, but technical, environmental, transportation and refining constraints make near-term increased production unlikely because of unfavorable economics. The harsh climate for thermal (steam) recovery of Alaska Heavy Oil (AHO) and the high cost of transport of a more viscous oil (through the TransAlaska Pipeline to Valdez, Alaska, and then by tanker to the United States West Coast refineries) significantly add to the production and delivery cost of a low-priced heavier oil. Economic recoverability of this oil is highly sensitive to the availability of existing facilities on a cost-sharing basis.

With the legislative constraint of having to sell ANS crude to the United States, AHO would have to compete not only with world oil but also with heavy oil produced in California, which refines most of Alaska's current production. This has an adverse effect on production and exploitation of Alaskan, and perhaps also California, heavy oil resources. The major heavy oil refining capacity is in California, refining Californian heavy and 70 percent ANS. The United States Gulf Coast will refine light oil and Caribbean blended heavy oil. A few Midwest refineries will refine Canadian blended crude (bitumen, upgraded bitumen, and diluent) and light crudes. The price of heavy oil at the refinery gate will limit refining of AHO in California, as refiners will find imported Caribbean medium and heavy oil at a much lower price than AHO or will refine imported light- and medium-crude and make a better rate of return.

A number of enhanced oil recovery technologies for production of AHO have been reported, including gas, CO₂, in situ combustion, and steam. Thermal production of heavy oil (hot water/steam) has been attempted, but the results of the field pilot have not been made public. Constraints on producing heavy oil in Alaska indicate that even with significant economic incentives and a significant increase in oil prices, little of the heavy oil in Alaska will be produced. If the current production decline and lack of further investment continue because of lack of access to Alaska light oil reservoirs and because of better prospects elsewhere in the world, it is likely that there will not be sufficient infrastructure or light oil diluent (for blending with heavy oil to lower viscosity) available for the development, production, and transport of Alaska's heavy oil resource.

Limitations are also imposed by the harsh environment of Alaska. The fragile Arctic tundra is supported by thick permafrost that must be maintained because artificial islands in the permafrost are the support (base) for all drilling and production operations. This limits thermal recovery of the shallow heavy oil that is found
scattered in the shallow fluvial-dominated formations on the North Slope that lie above lighter oils that are currently being produced. Reinjection of produced gas mandates that the heavy oil will be some of the last resources developed because natural gas will be used to supplement pressure and as a solvent to recover more valuable lighter crude oil on the North Slope. Interior basins of Alaska are still unexplored, and significant potential exists outside current fields for discovery of significant light, medium, and heavy oils. Minimum throughput (300,000 barrels per day) on the TransAlaska Pipeline is a concern, but heavy oil will not keep the pipeline full, because the line was not designed to transport viscous heavy oil.

On the basis of publicly available data, Olsen, et al., determined that little of the heavy oil in Alaska is likely to be developed without significant economic incentives and even then the cost may be prohibitively expensive compared with that for heavy oil development in other parts of the United States or the world; thus most of Alaska’s heavy oil may never be produced. This oil has to compete on the world oil market even though legislative constraints mandate that ANS must be sold to the United States. This makes AHO compete directly with heavy oil produced in California, and the transportation cost of AHO to California may exceed $10 per barrel.

With current constraints, Olsen, et al., conclude that the heavy oil fields in California, Wyoming, and the Gulf Coast States (Texas, Arkansas, Louisiana, and Mississippi) will be developed long before Alaska’s.

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STATUS OF OIL SANDS PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since December 1993)

ASPHALT FROM TAR SANDS — James W. Bunger and Associates, Inc. (T-5)

J. W. Bunger 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 UPGRADE — Husky Oil Operations Ltd. (26.7%), Government of Canada (31.7%), Province of Alberta (24.2%), Providence of Saskatchewan (17.5%) (T-10)

Husky Oil has built a heavy oil upgrader located near the Alberta/Saskatchewan border at Wilton, near Lloydminster, Saskatchewan. The facility is designed to process 46,000 barrels per day of heavy oil and bitumen from the Lloydminster and Cold Lake deposits. The primary upgrading technology used at the upgrader is H-Oil ebullated bed hydrocracking followed by delayed coking of the hydrocracker residual. The output is 46,000 barrels per day of high quality synthetic crude oil, as well as 400 tonnes per day of coke and 235 tonnes per day of molten sulfur.

The project was completed in the early fall of 1992 and, as of December 31, 1992, has produced over 4 million barrels of synthetic crude oil, well ahead of forecast.

Currently, Husky's cost to produce synthetic crude from heavy oil is greater than its market value, but that is expected to change over the next several years.

The project includes a crude oil unit, hydrocracker reaction unit, fractionation unit, delayed coking unit, naphtha-jet hydrotreater, gas-oil hydrotreater, hydrogen plant, gas-recovery unit and sulfur-recovery unit.

Project Cost: Upgrader Facility: C$1.6 billion

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.

A Solv-Ex pilot plant, located in Albuquerque, New Mexico, can process up to 72 tons of oil sands per day. It can also produce up to 25 barrels of bitumen per day, depending on the grade of oil sands processed. The quantity of bitumen recoverable from tar sands depends on its bitumen content, which typically ranges from 4 to 12 percent.
COMMERCIAL PROJECTS (Continued)

In an 8-month test program, Solv-Ex processed approximately 1,000 tons of Athabasca tar sands material in process runs of low (6 percent of bitumen), average (8 to 10 percent), and high (12 to 14 percent) grade oil sands through the pilot plant. The test material was procured from a pit centrally located in the oil sands deposit on which the Bitumount Lease is located. Average percentage of bitumen recovered for the low, average and high grade sands were 75, 90 and 95 percent, respectively.

In February, 1989, a viable processing flowsheet was finalized which not only recovers the originally targeted gold, silver and titanium values but also the alumina values contained in the resource. Synthetic crude oil would represent about 25 percent of the potential mineral values recoverable from the Bitumount Lease.

The results of this work indicate that the first module could be a single-train plant, much smaller than the 10,000 barrels per calendar day plant originally envisaged. The optimum size will be determined in the preconstruction feasibility study and this module is estimated to cost not more than C$200 million.

The Bitumount lease covers 5,874 acres north of 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 project is located on the Burnt Lake property in the southern portion of the Primrose Range in northeast Alberta. Initial production levels will average 12,500 barrels per day.

According to the companies, the Burnt Lake project is a milestone because it will be the first commercial development of these heavy oil resources on the Primrose Range. This will require close cooperation with Canada's military.

The multi-phase Burnt Lake project, which was proposed to use cyclic steaming, was put on hold in 1986 due to low oil prices, then revived in 1987. The project was again halted in early 1989. By then, 44 wells in two clusters and 7 delineation wells had been drilled and cased.

A pilot was initiated at these wells in 1990 to test the cold flow production technique whereby the bitumen is produced together with some sand using a progressive cavity pump. Initial results were encouraging. Since then, twelve wells have been put on production. Production rates of 30 cubic meters per day have been achieved in some wells and the productivity appears to be limited by the capacity of the pumps. However, some wells produced at rates of 5 to 8 cubic meters per day. The productivity appears to be controlled by the geological structure and the sand quality of the reservoir. Operation problems necessitated revisions of well operation procedure and well completion program.

If successful, the cold flow production process may replace the cyclic steam stimulation process for commercial development.

Burnt Lake is estimated to contain over 300 million barrels of recoverable heavy oil.

COLD LAKE PROJECT – Imperial Oil Resources Limited (T-50)

In September 1983 the Alberta Energy Resources Conservation Board (AERCB) granted Esso Resources Canada Ltd. (now Imperial Oil Resources Limited) 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 Imperial's application to add Phases 7 through 10, which could eventually add another 44,000 barrels per day. Phases 7 and 8, which include about 240 wells, a steam-generating and distribution system, a bitumen collection pipeline and a central processing facility, were put into operation in 1993.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

Plant facilities for Phases 9 and 10 were completed in tandem with the Phases 7 and 8 plant, but Imperial has decided to defer further development of these phases due to the drop in global oil prices. When suitable market opportunities materialize, Imperial will drill the wells to fully utilize this plant capacity, expanding production by a further 20,000 barrels per day.

Project Cost: Approximately $770 million for first 10 phases.

DAPHNE PROJECT – Petro-Canada (T-60)

Petro-Canada is studying the possibility of a tar sands mining/surface extraction project to be located on the Daphne leases 65 kilometers north of Fort McMurray, Alberta. To date over 350 core holes have been drilled at the site to better define the resource. The project may involve farmout and/or sales of the property.

Currently, the project has been suspended pending further notice.

DIATOMACEOUS EARTH PROJECT – Texaco Inc. (T-70)

Texaco placed its Diatomite Project, located at McKittrick in California’s Kern County, in a standby condition in 1985, to be reactivated when conditions in the industry dictate. In 1991 the company is initiating steps to re-evaluate the technology needed to recover the oil and to evaluate the environmental compliance requirements for a commercial plant. Consideration will be given to restarting the Lurgi pilot unit.

The Company estimates that the Project could yield in excess of 300 million barrels of 21 to 23 degrees API oil from the oil-bearing diatomite deposits which lie at depths up to 1,200 feet. The deposits will be recovered by open pit mining and back filling techniques.

Project Cost: Undetermined

ELECTROMAGNETIC WELL STIMULATION PROCESS – Uentech Corporation, A Subsidiary of Electromagnetic Oil Recovery, Inc. (T-80)

Electromagnetic Oil Recovery Inc. (EOR), formerly Oil Recovery Systems (ORS) Corporation, through its subsidiary, Uentech Corporation, sponsored research and development at the Illinois Institute of Technology Research Institute (IITRI) on a single-wellbore electromagnetic stimulation technique for heavy oil. The technique uses the well casing to induce an electromagnetic field in the oil-bearing formation. Both radio frequency and 60 cycle electric voltage are used. The radio frequency waves penetrate deeply into the formation while the 60 cycle current creates resistive heating.

The first field test with a commercial well, initially producing about 20 barrels per day, was put into production in December 1985 in Texas, on property owned by Coastal Oil and Gas Corporation. In June 1986, ORS received permits from the Alberta Energy Resources Conservation Board, and stimulation started in a well in the Lloydminster area in Alberta, Canada. This well was drilled on a farmout from Husky Oil in the Wildmere Field. Primary production continued for about 60 days, during which the well produced about 6 barrels per day of 11 degrees API heavy oil. The well was then shut down to allow installation of the ORS electromagnetic stimulation unit. After power was turned on and pumping resumed on June 10, a sustained production of 20 barrels per day was achieved over the following 30 days. The economic parameters of the operation were within the range expected, and process energy costs have been demonstrated at around $1/bbl, according to ORS.

Additional projects under way with EOR, Inc.’s technology include:

Canada Northwest Energy Ltd. installed an electromagnetic heating system within a well located near Lashburn, Saskatchewan in February 1989. Production averaged triple the production rate which existed before installation of the EOR system. Pan Canadian Petroleum Co., Ltd. has had a project ongoing since late 1990, with encouraging results for this heavy oil application. In Utah, an EOR system was installed in a well owned by GHP Corporation during December 1991. The system was designed to overcome production problems associated with an oil containing a large amount of paraffin. Also in Utah, EOR has been contracted by Coors Energy company to test the process in a field which experiences production problems associated with paraffinic oil. In Wyoming, Marathon Oil Company installed the EOR equipment within a well near Cody, Wyoming in late 1990. EOR was contracted by Shell to provide equipment and services to utilize the technology within a well in the Schoonebeek field of the Netherlands. The project resulted in EOR signing a contract for additional work for another Shell affiliate, Petroleum Development Oman. For Lagoven, EOR has been contracted to provide equipment and services for two wells in the Jobo Field of Venezuela, with startup scheduled for late summer of 1992. In Indonesia, a project is pending with Pertamina for a deep well which experiences paraffin related production problems. In Brazil, EOR’s project is slowly expanding. Currently four additional wells have been equipped with the EOR system with positive results for Petrobras.

Project Cost: Not disclosed
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

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 I Thermal Project is located on 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 970 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.

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 may be planned in future years. Phase 2 was approved in 1993, however, no new development is expected. Existing wells will be produced on a primary basis.

Project Cost: Phase 1 - $50 Million (Canadian)

ELK POINT OIL SANDS PROJECT – PanCanadian Petroleum Limited (T-100)

PanCanadian received approval from the Alberta Energy Resources Conservation Board for Phase I of a proposed three phase commercial bitumen recovery project in August 1986.

The Phase I project was to involve development of primary and thermal recovery operations in the Lindbergh and Frog Lake sectors near ElkPoint in east-central Alberta. Phase I operations were to include development of 16 sections of land. By the end of 1990, 148 wells were drilled.

PanCanadian expected Phase I recovery to average 3,000 barrels per day of bitumen, with peak production at 4,000 barrels per day. Tentative plans called for Phase II operations to start up in the mid 1990's with production to increase to 6,000 barrels per day. Phase III was to go into operation in the late 1990's, and production was to increase to 12,000 barrels per day.

Experimental steam stimulation (50 cycles) and steamflood (one pattern) lasted until mid-1990. Results were not encouraging and therefore all steaming operations have been canceled. Another steaming process such as SAGD (Steam Assisted Gravity Drainage) may be attempted in the future but no plans are currently in place.

Although steaming has proved unsuccessful, primary production rates and cumulative recoveries are much better than originally anticipated. Recoveries as high as 12 to 20 percent on 20-acre and 10-acre spacing are expected utilizing slant wells from pads. Consequently, the focus is now on primary production.

Current production is 10,500 barrels per day from 170 wells in 19 sections. Plans are in place to drill 120 wells in 1994, which will increase oil production to 16,500 barrels per day.

Project Cost: Phase I = C$62 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 degree 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 1992 production was 410 barrels of oil per day.

Project Cost: Estimated $42.5 million

LINDBERGH COMMERCIAL PROJECT — Amoco Canada Petroleum Company Ltd. (T-120)

Amoco (formerly Dome Petroleum) began a commercial project in the Lindbergh area that would initially cover five sections and was planned to be developed at a rate of one section per year for five years. It was to employ "huff-and-puff" steaming of wells drilled on 10 acre spacing, and would require capital investment of approximately $158 million (Canadian). The project was expected to encompass a period of 12 years. Due to the dramatic decline of oil prices, drilling on the first phase of the commercial project was halted, and has forced a delay in the proposed commercial thermal development.

The company has no immediate plans for steaming the wells to increase production because this process is uneconomic at current prices.

The current focus has been development and optimizing of primary production. In 1990, 26 wells on 40-acre spacing were drilled for primary production. Again, due to low heavy oil prices, some limited drilling will take place in 1991. Primary production from the project is now averaging 6,200 barrels per day.

Project Cost: $158 Million

LINDBERGH COMMERCIAL THERMAL RECOVERY PROJECT — Murphy Oil Company Ltd. (T-130)

Murphy Oil Company Ltd. has completed construction and startup of a 2,500 barrel per day commercial thermal recovery project in the Lindbergh area of Alberta. Project expansion to 10,000 barrels per day is planned over nine years, with a total project life of 30 years. The first phase construction of the commercial expansion involved the addition of 53 wells and construction of an oil plant, water plant, and water source intake and line from the North Saskatchewan River.

Murphy has been testing thermal recovery methods in a pilot project at Lindbergh since 1974. Based on its experience with the pilot project at Lindbergh, the company expects recovery rates in excess of 15 percent of the oil in place. Total production over the life of this project is expected to be in excess of 12 million cubic meters of heavy oil.

The project uses a huff-and-puff process with about two cycles per year on each well. Production is from the Lower Grand Rapids zone at a depth of 1,650 feet. Oil gravity is 11 degrees API, and oil viscosity at the reservoir temperature is 85,000 centipoise. The wells are directionally drilled outward from common pads, reducing the number of surface leases and roads required for the project.

The project was suspended for a year from September 1988 to August 1989 when three wells were steamed. The project returned to production on a limited basis in the last quarter of 1989. Initial results were encouraging, says Murphy, but an expansion to full capacity depends on heavy oil prices, market assessment, and operating costs.

The project was shut-in in late 1991. Engineering reviews of current and alternate technologies are under way.

In late 1993 a horizontal well was drilled, offsetting eight of the directionally drilled cyclic wells. Five of these were converted to injection wells and a steam drive process using the horizontal well as a producer is being tested.

Project Cost: $30 million (Canadian) initial capital cost

SYNTHETIC FUELS REPORT, MARCH 1994
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

NEWGRADE HEAVY OIL UPGRADE (THE CO-op UPGRADE) – 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.

The refinery/crude unit has been running at well over 50,000 barrels per day of heavy/medium crude. From that, 32,000 barrels per day of heavy resid bottoms are sent to the Atmospheric Residual Desulfurization (ARDs) unit which performs primary upgrading. From there 15,000 barrels per day is being run through the Distillate Hydrotreater (DHU) 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 contributed their existing refinery to the project, while the provincial government provided 20 percent equity funds. The federal government and the Saskatchewan government provided loan guarantees for 80 percent of the costs as debt.

NewGrade selected process technology licensed by Union Oil of California for the ARDS and DHU. The integrated facility is capable of producing a full slate of refined products or alternatively 50,000 barrels per day of upgraded crude oil or any combination of these two scenarios.

Operations include the processing of over 50,000 barrels per day of heavy and medium 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.

Operations in 1993 have experienced a heavy crude oil charge ratio of up to 54,000 barrels per day, and the Atmospheric Residual Desulfurization (ARDs) unit has had a charge ratio of 32,000 barrels per day. The Distillate Hydrotreater/Hydrocracker routinely operates at up to 15,000 barrels per day.

The plant design capacities are: crude unit, 50,000 barrels per day; ARDS, 30,000 barrels per day; DH, 12,000 barrels per day.

As a result of continuing financial difficulties, the terms of the partnership between Consumer's Cooperative Refineries and Saskatchewan were renegotiated in 1993. Under the new deal, Saskatchewan and Consumer's Cooperative will both contribute $75 million and both will share cash flow deficiencies equally up to $4 million.

Project Cost: $700 million

ORIMULSION PROJECT – Petroleos de Venezuela SA (PDVSA) and Veba Oel AG (T-145)

Venezuela's state-owned oil company, Petroleos de Venezuela SA (PDVSA), and Germany's Veba Oel AG are developing the heavy crude and bitumen reserves in the Orinoco Belt in eastern Venezuela. The two companies conducted a feasibility study to construct a facility capable of upgrading 80,000 barrels per day of extra heavy crude. Development plans for the next 5 years call for production of 1 million barrels per day.

About 60 percent of this production would be Orimulsion, a bitumen based boiler fuel. The remainder would be converted to light synthetic crude oil. PDVSA can produce and distribute 50,000 barrels of Orimulsion per day, with capacity in hand to double that.

Orimulsion has been produced from the Morichal Field in Eastern Venezuela since May 1988.

PDVSA joined forces with Mobil Corporation in 1992 to explore other options for marketing heavy crude in addition to Orimulsion.

In October 1991, the Kashima-Kita Electric Power Corporation of Japan began firing their generators with 700 tons per day of Orimulsion. Another Japanese utility, Mitsubishi Kasei Corporation, began working with Orimulsion in February 1992. Other markets for Orimulsion now include Power Gen, Great Britian and New Brunswick Power Company in Canada.

PDVSA's research institute, Intevep, is developing EVC Orimulsion, an 80 percent bitumen, controlled viscosity, emulsion fuel with improved stability. EVC Orimulsion has been tested at pilot plants in Morichal, Venezuela, according to Intevep, and the fuel is expected to reduce land and marine transportation costs, while delivering higher energy content per pound. The new and improved fuel is scheduled to enter the market sometime in 1994.

Project Cost: $2.5 billion
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

OSLO PROJECT - Imperial Oil Ltd. (25 percent), Canadian Occidental (20 percent), Gulf Canada (20 percent), Petro-Canada (10 percent), PanCanadian Petroleum (10 percent), Alberta Oil Sands Equity (10 percent). (T-150)

The OSLO joint venture was to be an 80,000 barrel per day oil sands mine and extraction plant 60 kilometers north of Fort McMurray, and an upgrader situated about 7 kilometers south of Redwater, near Edmonpon. Production was scheduled to begin in 1996.

On February 20, 1990 the Canadian federal government announced the withdrawal of its previous commitment to finance $1.6 billion of the $4.5 billion project. To the end of 1989, $75 million had been spent on project studies. In mid-1990, however, the Alberta government pledged to provide $47 million to complete the engineering phase. Alberta’s contribution represented 36 percent of the estimated $130 million total cost for the engineering phase. The Canadian federal government contributed about $45.5 million, 35 percent of the total, for the engineering phase. The OSLO consortium funded the rest.

The engineering phase was completed by the end of 1991. Engineering work was focused on the Edmonton-area upgrader to be linked directly to OSLO’s Fort McMurray bitumen production via pipeline. The pipeline is planned to be open to other operators to move their product. A second pipeline would return the diluent to the bitumen production facility.

If built, the project would use conventional surface mining techniques to strip the overburden and mine the oil sands. At the plant, the bitumen would be extracted from the sand by warm water and chemicals and sent to the upgrader by pipeline. There, it would be converted into synthetic crude oil with properties similar to conventional light crude oil—suitable as feedstock for Canadian refineries. OSLO has selected the high-conversion Veba Combi Cracking process for upgrading.

According to OSLO, the OSLO reserves are large enough that a project could produce 200,000 barrels of synthetic crude oil per day for almost 50 years.

In early 1992 the OSLO partners decided that they could go no further with the project without government support. When the final work on technical design and environmental assessment was completed, the OSLO offices in Calgary, Alberta were closed. The project will not be built until economic conditions improve.

Project Cost: $4.5 billion estimated

PEACE RIVER COMPLEX – Shell Canada Limited (T-160)

Shell Canada Limited expanded the original Peace River In Situ Pilot Project to an average production rate of 10,000 barrels per day. The Peace River Expansion Project, or PREP I, is located adjacent to the existing pilot project, approximately 55 kilometers northeast of the town of Peace River, on leases held jointly by Shell Canada Limited and Peden 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. 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. The operation is producing about 10,000 barrels per day of bitumen. Ultimate recovery is projected at 55 percent of the bitumen in place.

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.

Research into the application of a steam drainage process has led to the design of a two-well horizontal well demonstration project. The project is testing the technical and economic feasibility of bitumen recovery utilizing surface-accessed horizontal wells, employing an enhanced steam assisted gravity drainage process. The project is tied into existing Peace River complex facilities and began operating in November 1993. After steam injection for two months, production was expected to be about 1,000 barrels per day.

SYNTHETIC FUELS REPORT, MARCH 1994
PRIMROSE LAKE COMMERCIAL PROJECT — Amoco Canada Petroleum Company and Alberta Energy Company (T-170)

Amoco (formerly Dome) proposed a 25,000 barrels per day commercial project in the Primrose area of northeastern Alberta. Amoco is earning a working interest in certain oil sands leases from Alberta Energy Company. Following extensive exploration, the company undertook a cyclic steam pilot project in the area, which commenced production in November 1983, and thereby earned an interest in eight sections of adjoining oil sands leases. The 41 well pilot was producing 2,000 barrels per day of 10 degrees API oil in 1984.

The agreement with Alberta Energy allows Amoco to earn an interest in an additional 194,280 acres of adjoining oil sands lands through development of a commercial production project. The project is estimated to carry a capital cost of at least $1.2 billion and annual operating cost of $140 million. Total production over a 30 year period will be 190 million barrels of oil or 18.6 percent of the oil originally in place in the project area. Each section will contain four 26-well slant-hole drilling clusters. Each set of wells will produce from 160 acres on six acre spacing. The project received Alberta Energy Resources Conservation Board approval on February 4, 1986. A subsequent amendment to the original scheme was approved on August 18, 1988. The 12,800 acre project will be developed in three phases. Four 6,500 barrel per day modules will be used to meet the 25,000 barrel per day target.

In 1989, Amoco undertook some additional work at the site by drilling a horizontal well. In 1990 Amoco announced it would drill two more wells to assist in engineering design work. Six hundred thousand dollars was planned to be spent on this effort in 1990.

A new steam injection heavy oil pilot was placed in production in early 1991. By the end of 1991, AEC expected to be testing more than 80 wells using various techniques, including a cold technique which employs specialized pumps.

In 1991, ERCB gave approval for seven horizontal wells to maximize bitumen recovery under a steam stimulation/gravity drainage process.

AEC expects its share of Primrose heavy oil production to grow to about 10,000 barrels per day over the next 5 years and double by the late 1990s.

Using a newly developed "cold production" technique, four wells have been producing for more than a year at rates averaging 140 barrels per day per well. This technique significantly reduces capital and operating costs as compared to steam injection techniques. Further testing of this technology continues in 1992.

AEC estimates that cold production technology could yield 6,000 barrels per day by 1993, with a planned expansion to 12,500 barrels per day in 1995.

Project Cost: $1.2 billion (Canadian) capital cost
$140 million (Canadian) annual operating cost

SCOTFORD SYNTHETIC CRUDE REFINERY - Shell Canada Limited (T-180)

The project is the world's first refinery designed to use exclusively synthetic crude oil as feedstock, located northeast of Fort Saskatchewan in Strathcona County.

Initial capacity was 50,000 barrels per day with the design allowing for expansion to 70,000 barrels per day. Feedstock is provided by the two existing oil sands plants, Syncrude and Suncor. The refinery's petroleum products are gasoline, diesel, jet fuel and stove oil. Byproducts include butane, propane, and sulfur. Sufficient benzene is produced to feed a 300,000 tonne/year styrene plant. The refinery and petrochemical plant officially opened September 1984.

Project Cost: $1.4 billion (Canadian) total final cost for all (refinery, benzene, styrene) plants

SUNCOR, INC., OIL SANDS GROUP — Sun Company, Inc. (72.8 percent), RBC Dominion Securities and Scotia McLeod Inc. (25 percent), publicly (2.2 percent) (T-190)

Suncor Inc. was formed in August 1979, by the amalgamation of Great Canadian Oil Sands and Sun Oil Co., Ltd. In November 1981, Ontario Energy Resources Ltd., acquired a 25 percent interest in Suncor Inc.

Suncor Inc. operates a commercial oil sands plant located in the Athabasca bituminous sands deposit 30 kilometers north of Fort McMurray, Alberta. It has been in production since 1967. A four-step method is used to produce synthetic oil. First, overburden is removed to expose the oil-bearing sand. Second, the sand is mined and transported by conveyors to the extraction unit. Third,
COMMERCIAL PROJECTS (Continued)

hot water and steam are used to extract the bitumen from the sand. Fourth, the bitumen goes to upgrading where thermal cracking produces coke, and cooled vapors form distillates. The distillates are desulfurized and blended to form high-quality synthetic crude oil which is shipped to Edmonton for distribution.

In November 1991, Suncor applied to the ERCB to increase primary bitumen production as much as 2,000 cubic meters per day. After December 31, 1991, the royalty changed to be the greater of 5 percent of revenues or 30 percent of revenues less allowed operating and capital costs.

Sun Company, Inc. announced in early 1992 its intention along with partner Ontario Energy Corporation (OEC) to sell up to 45 percent interest in Suncor. Sun intends to reduce its 75 percent share to 55 percent and OEC would sell its entire 25 percent interest in Suncor.

The plant achieved record production levels in the first quarter of 1992, averaging 64,200 barrels per day, or about 250,000 barrels above the same period last year. Cash operating costs remained at 1991 levels of $14.25 per barrel.

In 1992 Suncor announced restructuring and operating changes aimed at reducing the cost of producing synthetic crude oil by $5 to $7 per barrel by 1996. Lowering production costs by that amount would increase the company's cash flow by $125 to $175 million per year and make synthetic crude oil competitive with Canadian conventional crude oil.

Suncor now has written agreements to acquire new mining leases in proximity to its plant that will allow the company to produce an additional 1 billion barrels of light synthetic crude oil. At the plant's current production rates, Suncor now has sufficient bitumen to supply the upgrader for at least 50 years.

To reduce mine operating costs, Suncor will introduce a more flexible and efficient mining method by mid-1994. The 25-year-old bucketwheel excavator systems will be replaced with a more modern system of large-scale trucks, power shovels and ore feed crushers at a cost of approximately $100 million. Truck and shovel mining equipment, which has reached unprecedented dimensions of size and scale in recent years, will enhance reliability and productivity and should result in significant gains in both production and cost savings. By mid-1994, Suncor believes these initiatives alone will reduce cash costs by approximately $3 per barrel of synthetic crude oil.

In addition, to provide steam and electricity to Suncor's oil sands operation, near Fort McMurray, Suncor Inc. and Canadian Utilities Ltd. have agreed to jointly develop, own, and operate a cogeneration plant to replace Suncor's existing steam and electric plant. The new unit is expected to cost about $270 million and will use fluidized bed combustion to reduce sulfur dioxide emissions from Suncor's operation by at least 75 percent. The plant is also expected to reduce operating costs by C$30 to C$40 million per year, or about C$1.50 per barrel. It is scheduled to be commissioned in mid-1996.

Suncor will also be implementing other operating efficiencies and production improvements that are expected to result in a cash cost reduction of up to $2.50 per barrel. Modifications were be made to the upgrader during a maintenance turnaround in 1993 that will boost production capacity to 68,000 barrels per day by 1994 and conversion to a new shovel and truck mining system is on schedule for completion by year end 1993. Implementation of the plan means that employment levels will be gradually reduced. As the new mining method is introduced, employment will drop from 2,400 to about 2,000.

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 mixed 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 before giving any financial assistance to the project. GNC is now attempting to finance independently of United States government assistance. Studies have been completed by M. W. Kellogg and Engelhard indicating feasibility, after the decline in prices beginning in January 1986, of a 7,500 barrels per day plant which converts the ART-treated bitumen to 31 percent gasoline and 69 percent diesel. The 7,500 barrels per day plant including upgrading to products, with some used equipment, would cost $149 million.

As of mid-1993, GNC is still looking for financial partners, however, little progress has been made since the 1980's.

Project Cost: $149 million for 7,500 barrels per day facility

SYNCO SUNNYSIDE PROJECT - Synco Energy Corporation (T-220)

Synco Energy Corporation of Orem, Utah is seeking to raise capital to construct a plant at Sunnyside in Utah's Carbon County to produce oil and electricity from coal and tar sands.

The Synco process to extract oil from tar sands uses coal gasification to make a synthetic gas. The gas is cooled to 2,000 degrees F by making steam and then mixed with the tar sands in a variable speed rotary kiln. The hot synthetic gas vaporizes the oil out of the tar sands and this is then fractionated into a mixture of kerosene (jet fuel), diesel fuel, gasoline, other gases, and heavy ends.

The syngas from the gasifier is separated from the oil product, the sulfur and CO2 removed and the gas is burned in a gas turbine to produce electriciy. The hot exhaust gases are then used to make steam and cogenerated electricity. Testing indicates that the hydrogen-rich syngas from the gasified coal lends to good cracking and hydrogen upgrading in the kiln.

The plant would be built at Sunnyside, Utah, near the City of Price.

There is a reserve of four billion barrels of oil in the tar sands and 230 million tons of coal at the Sunnyside site. Both raw materials could be conveyed to the plant by conveyor belt.

The demonstration size plant would produce 8,000 barrels of refined oil, 330 megawatts of electricity, and various other products including marketable amounts of sulfur.

An application has been filed by Synco with the Utah Division of State Lands for an industrial special use lease containing the entire Section 36 of State land bordering the town of Sunnyside, Utah. Synco holds process patents in the U.S., Canada and Venezuela and is looking for a company to joint venture with on this project.

Project Cost: $350 million
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

SYNCRUDE CANADA, LTD. – Imperial Oil Resources (25.0%); Petro-Canada (12.0%); Alberta Oil Sands Equity (16.74%); Alberta Energy Company Ltd. (10.0%); PanCanadian Petroleum Limited (10.0%); Gulf Canada Resources Limited (9.03%); Canadian Occidental Petroleum Ltd. (7.23%); HEOG - Oil Sands Ltd. Partnership (Amoco Canada Petroleum Company Ltd.) (5.0%); Mocal Energy Limited (5.0%)

Located near Fort McMurray, the Syncrude surface mining and extraction plant produces 180,000 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 $15 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 were 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 1992 production operating costs were about C$15.39 per barrel. Syncrude Canada Ltd. produced 11 percent of Canada’s crude oil requirements in 1992.

In 1992, Syncrude announced that it is seeking approval from the Alberta Energy Resources Board (ERCB) to increase output by 28 percent.

Syncrude is requesting five amendments to its current ERCB approval:

An annual production increase to 217,000 barrels per day of marketable hydrocarbon for the existing plant

An extension to December 31, 1997 to begin construction of new facilities that would allow production to be increased to 258,000 barrels per day (1993 estimated cost of C$4.0 billion)

An extension of Syncrude’s production period to December 31, 2025

The ability to process bitumen from off-lease sites and to ship bitumen from Mildred Lake to other processing operations

The ability to use new technology, developed by Syncrude, for future mining and reclamation plans

In 1992, Syncrude produced 65.4 million barrels of high quality, light sweet synthetic crude oil. The 1993 production target is 68 million barrels.

Project Cost:  C$1+ billion

THREE STAR OIL MINING PROJECT - Three Star Drilling and Producing Corp. (T-240)

Three Star Drilling and Producing Corporation has sunk a 426 foot deep vertical shaft into the Upper Siggins sandstone of the Siggins oil field in Illinois and drilled over 34,000 feet of horizontal boreholes up to 2,000 feet long through the reservoir. The original drilling pattern was planned to allow the borehole to wander up and down through the producing interval in a "snake" pattern. However, only straight upward slanting holes are being drilled. Three Star estimates the Upper Siggins still contains some 35 million barrels of oil across the field.

The initial plans call for drilling one to four levels of horizontal boreholes. The Upper Siggins presently has 34 horizontal wells which compose the 34,000 feet of drilling.

Sixty percent of the horizontal drilling was completed by late 1990. Production was put on hold pending an administrative hearing to determine whether the mine is to be classified as gaseous or non-gaseous. The project was later classified as a gaseous mine due to the fact that the shaft penetrated the oil reservoir. As a result of the ruling, Three Star then drilled a vertical well to the underground sump room and began producing the mine conventionally with all the horizontals open. In 1992, Three Star will begin reworking the surface wells for injection purposes in order to pressure up the Upper Siggins.

Project Cost:  Three Star budgeted $3.5 million for the first shaft.

WOLF LAKE PROJECT – Amoco Canada Petroleum (T-260)

Located 30 miles north of Bonnyville near the Saskatchewan border, on 75,000 acres, the Wolf Lake commercial oil sands project (a joint venture between BF 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.
COMMERCIAL PROJECTS (Continued)

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 1,630 cubic meters per day in 1989 and 1,147 cubic meters per day in 1990. Continuing the trend, 1991 will see an average production rate of 1,167 cubic meters per day.

In 1987, a program designed to expand production by 2,400 cubic meters per day to 3,700 cubic meters per day, total bitumen production was initiated. Wolf Lake 2 was originally expected to be completed in mid-1989.

In early 1989, BP Canada and Petro-Canada delayed by 1 year the decision to start up the second phase. While the Wolf Lake 2 plant was commissioned in 1990, full capacity utilization of the combined project is not likely before the late 1990s when it is expected that higher bitumen prices will support the expanded operation and further development.

The new water recycle facilities and the Wolf Lake 2 generators are operational. Production levels will be maintained at 600 to 700 cubic meters per day until bitumen netbacks have improved. The Wolf Lake 2 oil processing plant and Wolf Lake 1 steam generating facilities have been suspended.

In September 1989, Wolf Lake production costs were reported to be almost $22 per barrel, while bitumen prices fell to a low of $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 $10 to 12 per barrel.

In 1991, Wolf Lake production costs were less than $9 per barrel, and bitumen production averaged 4,225 barrels a day.

In early 1992, BP Canada and Petro-Canada sold their entire interests in the project to Amoco Canada Petroleum. No price was disclosed but both companies have written off their total $370 million investment in the project.

<table>
<thead>
<tr>
<th>Project Cost</th>
<th>Wolf Lake 1</th>
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<tr>
<td></td>
<td>$114 million (Canadian) initial capital</td>
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<td>(Additional $750 million over 25 years for additional drilling)</td>
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<table>
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<tr>
<th>Project Cost</th>
<th>Wolf Lake 2</th>
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<td>$200 million (Canadian) initial capital</td>
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YAREGA MINE-ASSISTED PROJECT -- Union of Soviet Socialist Republics (T-265)

The Yarega oilfield (Soviet Union) is the site of a large mining-assisted heavy oil recovery project. The productive formation of this field has 26 meters of quartz sandstone occurring at a depth of 200 meters. Average permeability is 3.17 mKm⁻¹. Temperature ranges from 279 to 281 degrees K; porosity is 26 degrees; oil saturation is 87 percent of the pore volume or 10 percent by weight. Viscosity of oil varies from 15,000 to 20,000 mPa per second; density is 945 kilograms per cubic meter.

The field has been developed in three major stages. In a pilot development, 69 wells were drilled from the surface at 70 to 100 meters spacing. The oil recovery factor over 11 years did not exceed 1.5 percent.

Drainage through wells at very close spacing of 12 to 20 meters was tested with over 92,000 shallow wells. Development of the oilfield was said to be profitable, but the oil recovery factor for the 18 to 20 year period was approximately 3 percent.

A mining-assisted technique with steam injection was developed starting in 1968. In 15 years, 10 million tons of steam have been injected into the reservoir.

Three mines have been operated since 1975. An area of the deposit covering 225 hectares is under thermal stimulation. It includes 15 underground slant blocks, where 4,192 production wells and 11,795 steam-injection wells are operated. In two underground slant production blocks, which have been operated for about 8 years, oil recovery of 50 percent has been reached. Construction of 4 new shafts is expected to bring production to over 30,000 barrels per day. Forty-one million barrels of oil were produced during the period 1975-1987. A local refinery produces lubricating oils from this crude.

| Project Cost | Not Disclosed |
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

R & D PROJECTS

ATHABASCA IN SITU PILOT PROJECT (Kearl Lake) -- Alberta Oil Sands Technology and Research Authority, Husky Oil Operations Ltd., Imperial Oil 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

BATTROM 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 1964 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 17 burns in operation.

All burns have been converted to wet combustion and the air injection rate is 25 million cubic feet per day. In 1988, studies were initiated to determine the feasibility of oxygen enrichment for the EOR scheme. Due to increased capital requirements for the oxygen case in 1991, application of horizontal well technology was considered as an alternative. In late 1992, Mobil and partners drilled the first horizontal well to take advantage of gravity drainage. Results to date are encouraging both from technical and economic points of view. Currently, a phased field development scheme utilizing horizontal wells is being engineered.

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 involves testing the technology in a small pilot plant installed near Weber State University. The plant was built in Texas and was shipped to Utah in the fall of 1990 for installation. This was begun successfully in 1992. The project's second phase will be a larger pilot plant and the third phase will be a commercial-scale plant.

Buenaventura has been working on developing the new process in Uintah County, Utah since 1986. Funding for the project is being sought from the State of Utah and the United States Department of Energy.

CARIBOU LAKE PILOT PROJECT -- Husky Oil Operations Ltd. (60 percent) and Alberta Energy Co. (40 percent) (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 steaming technology. Husky will operate the project.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

Construction at the Caribou Lake Pilot Project was completed in early 1991 and the operations phase of the project was begun. The Pilot consists of 25 cyclic steam/production wells, 75 MMBTU/hour steam generation capacity and associated oil treating and produced water clarification facilities. The total average output of the project was expected to be 1,200 barrels of heavy oil per day.

In 1992 the Caribou Lake Project was suspended indefinitely.

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 consisted of 25 wells drilled on 5-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. Steam operations continued until April 1991, and there after, wells were put on primary production. This test operation is now part of the total Celtic field operation.

Project Cost: $21 million (Canadian) (Capital)

C-H SYNFUELS DREDGING PROJECT - C-H Synfuels Ltd. (T-330)

C-H Synfuels Ltd. plans to construct an oil sands dredging project in Section 8, Township 89, Range 9, west of the 4th meridian. The scheme would involve dredging of a cutoff meander in the Horse River some 900 meters from the Fort McMurray subdivision of Abasand Heights. Extraction of the dredged bitumen would take place on a floating modular process barge employing a modified version of the Clark Hot Water Process. The resulting bitumen would be stored in tanks, allowed to cool and solidify, then transported, via truck and barge, to either Suncor or the City of Fort McMurray. Tailings treatment would employ a novel method combining the sand and sludge, thus eliminating the need for a large conventional tailings pond.

C-H proposes to add lime and a non-toxic polyacrylamide polymer to the tailings stream. This would cause the fines to attach to the sand eliminating the need for a sludge pond.

Project Cost: Not disclosed

CIRCLE CLIFFS PROJECT – Kirkwood Oil and Gas (T-340)

Kirkwood Oil and Gas is forming a combined hydrocarbon unit to include all acreage within the Circle Cliffs Special Tar Sand Area, excluding lands within Capitol Reef National Park and Glen Canyon National Recreational Area.

Work on this project was suspended in 1990 until an Environmental Impact Statement can be completed.

Project Cost: Not disclosed

COLD LAKE STEAM STIMULATION PROGRAM - Mobil Oil Canada (T-350)

A stratigraphic test program conducted on Mobil's 75,000 hectares of heavy oil leases in the Cold Lake area resulted in approximately 150 holes drilled to date. Heavy oil zones with a total net thickness of 30 meters have been delineated at depths between 290 and 460 meters. This pay is found in sand zones ranging in thickness from 2 to 20 meters.

Single well steam stimulations began in 1982 to evaluate the production potential of these zones. Steam stimulation testing was subsequently expanded from three single wells to a total of fourteen single wells in 1988. Various zones have been tested in the Upper and Lower Grand Rapids formation. The test well locations are distributed throughout Mobil's leases in Townships 63 and 64 and Ranges 6 and 7 W4M. Based on encouraging results, the Iron River Pilot [see Iron River Pilot Project (T-440)] was constructed with operations beginning in March, 1988. To date, steam stimulation tests have been conducted in a total of 14 vertical wells.
R & D PROJECTS (Continued)

Single well tests were suspended at the end of 1991. 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 successfully completed in 1991. As of August 1993, the wells are suspended.

Project Cost: Not disclosed

DONOR REFINED BITUMEN PROCESS — Gulf Canada Resources Limited, the Alberta Oil Sands Technology and Research Authority, and L’Association pour la 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

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.

Three horizontal wells were drilled in 1992, with one inside the fireflood boundaries. Production from the project peaked at 1,300 barrels per day.

Project Cost: $15.2 million

FORT KENT THERMAL PROJECT — Koch Industries and Canadian Worldwide Energy Corporation (T-400)

Canadian Worldwide Energy Ltd. and Suncor, Inc., developed heavy oil deposits on a 4,960 acre lease in the Fort Kent area of Alberta. Canadian Worldwide holds a 50 percent working interest in this project, with Koch Industries now replacing Suncor. This oil has an average gravity of 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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

Because of the experimental work being carried out, this project qualifies for a reduced royalty rate of only 5 percent. Canadian Worldwide's share of the project costs to 1988 is approximately $35 million (Canadian).

In January 1989, it was announced that the project would be indefinitely suspended.

Project Cost: See Above

FROG LAKE PILOT PROJECT—Texaco Canada Petroleum (T-405)

The Frog Lake Lease is located about 50 miles northwest of Lloydminster, Alberta in the southeastern portion of the Cold Lake Oil Sands deposit. The lease contains a number of heavy oil producing horizons, but primary production rates are generally restricted to less than 5 cubic meters per day per well due in large part to the high viscosity of the oil.

During the 1960's steam stimulation treatments were carried out on several wells on the Frog Lake lease but based on these tests it was concluded that conventional thermal recovery methods using steam are hampered by the thermal inefficiency associated with the thin sands.

In 1991 Texaco began preparing to apply electromagnetic heating to stimulate three Lower Waseca wells at Frog Lake. The wells were placed on production in late November 1990 and electromagnetic heating was scheduled to commence by mid-1991.

Upon completion of the tests in 1993 it is expected there will be sufficient data available to develop reliable economics for a commercial project. A reservoir simulator will be used to history-match test results and make predictions of production rates and ultimate recovery for various well patterns and spacing.

GLISP PROJECT - Amoco Canada Petroleum Company Ltd. (14.29 percent) and AOSTRA (85.71 percent) (T-420)

The Gregoire Lake In-Situ Steam Pilot (GLISP) was an experimental steam pilot located at Section Z-86-TW. Phase B operations were terminated in July 1991 due to financial limitations. Petro-Canada had participated in Phase A of the project, but declined to participate in Phase B which was initiated in 1990. The lease is shared jointly by Amoco and Petro-Canada. Amoco is the operator.

The GLISP production pattern consisted of a four spot geometry with an enclosed area of 0.28 hectares (0.68 acres). The process tested the use of steam and steam additives in the recovery of high viscous bitumen (1x10 million eP at virgin reservoir temperature). Special fracturing techniques were tested. Three temperature observation wells and seismic methods were used to monitor the in-situ process.

The project began operation in September 1985. Steaming operations were initiated in October 1986 to heat the production wellbores. A production cycle was initiated in January 1987 and steam foam flooding began in October 1988. Foam injection was terminated in February 1991. Steam diversion using low temperature oxidation was tested between April and July 1991. Operations at GLISP were suspended July 18, 1991.

Project Cost: $26 million (Canadian)

HANGINGSTONE PROJECT - Petro-Canada, Canadian Occidental Petroleum Ltd., Imperial Oil Ltd. and Japan Canada Oil Sands Limited (T-430)

Construction of a 13 well cyclic steam pilot with 4 observation wells was completed and operation began on May 1, 1990. On September 4, 1990, Petro-Canada announced the official opening of the Hangingstone Steam Pilot Plant.

The production performance of the first two cycles was said to be below expectations because of severe steam override. Cold bitumen influx into the wellbore also caused severe rodfall problems and pump seizure. In May 1992, Petro-Canada, Canadian Occidental and Imperial Oil withdrew from further testing of the Cyclic Steam Simulation (CSS) process at Hangingstone. Japan Canada Oil Sands Limited (JACOS) assumed the piloting with Petro-Canada contract operating for JACOS.

Some of the pilot wells are now in their fourth production cycle.

Further testing of other in situ recovery processes by JACOS, alone or jointly with other Hangingstone owners, is possible following the current CSS test.

The Group owns 34 leases in the Athabasca oil sands, covering 500,000 hectares. Most of the bitumen is found between 200 and 500 meters below the surface, with total oil in place estimated at 24 billion cubic meters.
The Hangingstone operations are expected to continue until the end of 1994. According to JACOS, total expenditures will reach $160 million by 1994. Expansion to an enlarged pilot operation or a semi-commercial demonstration project could result if the current project is deemed successful.

**Imperial Cold Lake Pilot Projects** — Imperial Oil Resources Limited. (T-435)

Imperial 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 Lease No. 40. Imperial has sold data from these tests to several companies. The 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. Imperial 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 (about 19,500 barrels) per day of bitumen.

The pilots have been used for testing a variety of recovery, production and facilities technologies.

They continue to 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

**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 65 hectare drainage area. The project is 100 percent owned by Mobil Oil. It is located in the northwest quarter of Section 6-64-6W4 adjacent to the Iron River battery facility located on the southwest corner of the quarter section. The project is expected to produce up to 300 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.

The pilot project was successfully operated until mid-1991. The pilot is still suspended as of August 1993.

**Project Cost:** $14 million

**Kearl Lake Project** — See Athabasca In Situ Pilot Project (T-270)

**Lindbergh Steam Project** — Murphy Oil Company, Ltd. (T-470)

This experimental in situ recovery project is located at T3-58-5 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

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STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

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 percent oxygen.

In the second year of CTD, further oxygen breakthrough was controlled by stopping injection, then injecting air followed by 50 percent O₂. Lack of production response and corrosion caused the pilot to be shut in in mid-1990.

Project Cost: $22 million

MINE-ASSISTED PILOT PROJECT — (see Underground Test Facility Project)

MORGAN COMBINATION THERMAL DRIVE PROJECT — Amoco Canada Petroleum Company Ltd. (T-490)

Amoco (formerly Dome) completed a 46 well drilling program (7 injection wells, 39 production wells) in Section 35-51-4-W4M in the Morgan field in order to evaluate a combination thermal drive process. The project consists of nine 30-acre seven spot 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 used for pressure cycle six scheduled for this year. A conversion to combination thermal drive is still planned after pressure cycling becomes unfeasible due to longer repressuring time requirements. The project started up in 1981 and is scheduled for completion in 1995.

Project Cost: $20 million

ORINOCO BELT STEAM SOAK PILOT—Maraven (T-500)

The Orinoco Belt of 54,000 km² was divided into four areas in 1979 to effect an accelerated exploration program by the operating affiliates (Corpoven, Lagoven, Maraven and Meneven) of the holding company Petroleos de Venezuela (PDVSA).

Maraven has implemented a pilot project in the Zuata area of the Orinoco Belt to evaluate performance of slant wells, productivity of the area, and well response to "Huff and Puff" steam injection in relation to a commercial development.

Twelve inclined wells (7 producers and 5 observers) have been drilled in a cluster configuration, using a slant rig with a well spacing at surface of 15 meters and 300 meters in the reservoir.

The 7 production wells, completed with openhole gravel packs, have been tested prior to steam injection at rates between 30 BPD and 200 BPD using conventional pumping equipment. Five wells have been injected, each with 10,000 tons of steam distributed selectively over two zones. After an initial flowing period, stabilized production on the pump averaged 1,400 BPD per well with a water cut of less than 3 percent.

With the information derived from the exploration phase, it was possible to establish an oil-in-place for the Zuata area of 487 billion STB.

PELICAN LAKE PROJECT — CS Resources Limited and Devran Petroleum Ltd. (T-510)

CS Resources acquired from Gulf Canada, the original operator, the Pelican Lake Project comprised of some 89 sections of oil sand leases.

The Pelican Lake program is designed to initially test the applicability of horizontal production systems under primary production methods, with a view to ultimately introducing thermal recovery methods.

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Eight horizontal wells have been successfully drilled at the project site in north central Alberta. The Group utilizes an innovative horizontal drilling technique which allows for the penetration of about 1,500 feet of oil sands in each well. With this technique, a much higher production rate is expected to be achieved without the use of expensive secondary recovery processes.

Drilling was commenced on the first horizontal well on January 30, 1988 and drilling of the eighth well was completed in June 1988. Drilling of five more horizontal wells with horizontal sections of 3,635 feet (a horizontal record) was accomplished in December 1989 and January 1990. Four more horizontal wells were drilled in 1991 for a total of 17 horizontal wells.

All four 1991 wells contacted almost 100 percent of good quality reservoir throughout the horizontal section. The horizontal section of one well was 1,321 meters from intermediate casing point to total depth. A 496 meter lateral arm was completed off the horizontal section of a 1,137 meter main hole section. One "J" well was a limited success with a horizontal section of 907 meters.

The average drill, case and completion cost of the 1991 wells was $540,000. The wells took an average of 7.5 days to drill with the average horizontal section being 1,290 meters. The cost per horizontal meter has dropped from $1,240 per meter in 1988 to $420 per meter in 1991.

Special effort was made to keep the drilling program simple and cost-effective. A surface casing was set vertically at 110 meters, then the wells were kicked off and inclination was built gradually to 90 degrees at a rate of two degrees/10 meters. An intermediate casing was run and cemented before horizontal drilling commenced in the sand reservoir. Early production rates averaged 15 to 20 cubic meters per day, three to six times average vertical well figures. Four wells, drilled in 1988, rapidly produced with a disappointing, and unexpected high water cut, whereas no bottom water is known to exist in this particular area. However, the two subsequent horizontal wells have not had any free water problems. Sand production has not been a major problem and the production sand content is lower than in surrounding vertical wells.

An additional six horizontal wells were drilled in 1993. To increase reservoir exposure, one of the 1993 wells was drilled and completed using the lateral tie-back system developed by CS Resources and Sperry-Sun Drilling Services. This system provides for the complex interconnection of individual production liners, thereby creating total wellbore integrity. The 1993 well drilled using this system has a total of 2,798 meters of horizontal section. The cost per horizontal meter for this well was $374. The average drill, case and completion cost of the 1993 wells was $670,000. The wells took an average of 10 days to drill with an average horizontal section of 1,702 meters. The average cost per horizontal meter for the 1993 wells was $416.

Project Cost: Not disclosed

PELICAN-WABASCA PROJECT — CS Resources (T-520)

Construction of fireflood and steamflood facilities is complete in the Pelican area of the Wabasca region. Phase I of the project commenced operations in August 1981, and Phase II (fireflood) commenced operations during September 1982. The pilot consists of a 31-well centrally enclosed 7-spot pattern plus nine additional wells. Oxygen injection into two of the 7-spot patterns was initiated in November 1984. Six more wells were added in March 1985 that completed an additional two 7-spot patterns. In April 1986, the fireflood operation was shut down and the project converted to steam stimulation. Sixteen pilot wells were cyclic steamed. One pattern was converted to a steam drive, another pattern converted to a water drive. The remaining wells stayed on production. In January/February 1986, 18 new wells were drilled and put on primary production. Cyclic steaming was undertaken in February 1987. The waterflood on the pilot ceased operation in April, 1987. Cyclic steaming of the producing wells on the 7-spot steamflood project south of the pilot was converted to steamflood in fall 1987.

In May 1989 all thermal operations had been terminated. The wells were abandoned with the exception of 13 wells that remain producing on primary production.

The use of horizontal wells is being tested. In 1991, an additional eight horizontal wells were drilled to about 1,000 meters in length.

Project Cost: Not Specified

PROVOST UPPER MANNVILLE HEAVY OIL STEAM PILOT — AOSTRA, Canadian Occidental Petroleum, Ltd., Imperial Oil Ltd., Murphy Oil, Noreen Energy Resources Limited (T-530)

Noreen Energy Resources Limited has applied to the Alberta Energy Resources Conservation Board to conduct an experimental cyclic steam/steam drive thermal pilot in the Provost Upper Mannville B Pool. The pilot project will consist of a single 20 acre inverted 9 spot pattern to be located approximately 20 kilometers southeast of Provost, Alberta.

An in situ combustion pilot comprising one 20 acre 5 spot was initiated in 1975. The pilot was expanded in 1982 to encompass seven 6 hectare 7 spot patterns.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

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 - Fed/86: Primary Production
Apr/86 - Jun/89: Cyclic Steam Stimulation
Jul/89 - Dec/92: Steam Drive
Jan/93 - Dec/94: Heat Scavenging Waterflood

Overall, the cyclic production performance had an average incremental recovery of 17 percent over the three-year cycle phase. The average calendar day oil rams were slightly less than the 11.9 cubic meters per day originally forecast with oil steam ratios higher than the 0.55 forecast.

The next phase of the pilot is to follow-up the four cycle steam stimulation phase with a steam drive by way of continuous injection into the central well. Performance thus far has been encouraging with production being equal to or better than forecast and slightly higher than at the end of the cyclic phase. The steam drive performance in 1991 and 1992 will be important in determining the ultimate recovery process and pattern size to be chosen for the pool.

Project Cost: $14 million capital, $2.5 million per year operating

PR SPRING PROJECT - Enercor and Solv-Ex Corporation, (T-540)

The PR Spring Tar Sand Project, a joint venture between Solv-Ex Corporation (the operator) and Enercor, was formed for the purpose of mining tar sand from leases in the PR Spring area of Utah and extracting the contained hydrocarbon for sale in the heavy oil markets.

The project's surface mine will utilize a standard box-cut advancing pit concept with a pit area of 20 acres. Approximately 1,600 acres will be mined during the life of the project. Exploratory drilling has indicated oil reserves of 58 million barrels with an average grade of 7.9 percent by weight bitumen.

The proprietary oil extraction process to be used in the project was developed by Solv-Ex in its laboratories and pilot plant and claims the advantages of high recovery of bitumen, low water requirements, acceptable environmental effects and low economical capital and operating costs. Process optimization and scale-up testing is currently underway for the Solv-Ex/Shell Canada Project which uses the same technology.

The extraction plant for the project has been designed to process tar sand ore at a feed rate of 500 tons per hour and produce net product oil for sale at a rate of 4,663 barrels per day over 330 operating days per year.

In August 1985 the sponsors requested loan and price guarantees totaling $230,947,000 under the United States Synthetic Fuels Corporation's (SFC's) solicitation for tar sands mining and surface processing projects. On November 19, 1985 the SFC determined that the project was qualified for assistance under the terms of the solicitation. However, the SFC was abolished by Congress on December 19, 1985 before financial assistance was awarded to the project.

The sponsors are evaluating various product options, including asphalt and combined asphalt/jet fuel. Private financing and equity participation for the project are being sought.

Project Cost: $158 million (Synthetic crude option)
$90 million (Asphalt option)

SOARS LAKE HEAVY OIL PILOT - Koch Exploration Canada 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 had been actively evaluating the heavy oil potential of its Soars Lake leases since 1965 when the company drilled two successful wells. 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.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

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 began testing the primary production potential of Soars Lake with six new wells drilled in June 1991.

In 1992 the project was transferred to Koch Exploration Canada.

Project Cost: $40 million

SOLV-EX MINERALS FROM TAR SANDS RESEARCH – Solv-Ex, AOSTRA (T-593)

Solv-Ex was originally organized for the purpose of developing a process to extract bitumen from oil sands. During the 1980s the company developed and continuously improved a patented process for bitumen extraction. A joint venture with Shell Canada Limited during 1987 and 1988 successfully processed approximately 1,000 tons of oil sands for bitumen recovery.

Following the joint venture with Shell, Solv-Ex undertook a research and test program for commercial recovery of metals, primarily aluminum, titanium, and iron, from both oil sands and tailings in an effort to improve the overall economics of production operations. As a result of such efforts, the company has developed patented process technology which it believes can be used in commercial operations for recovery of metals, either from tailings generated by others or from primary production of bitumen from the oil sands.

During 1992 and 1993, the company modified its Albuquerque pilot plant to incorporate the latest improvements in its bitumen extraction process and to add a circuit for production of minerals from oil sands tailings. Following such work, the company conducted a pilot program to demonstrate both bitumen extraction and production of minerals from oil sands and tailings. Approximately 100 tons of tailings and 100 tons of oil sands crude ore were processed during the program, all of which were obtained from the Athabasca region. Work is continuing at the pilot plant, primarily for the purpose of testing further improvements which have been made in the process, confirming product purity and evaluating the possibility of producing upgraded products for specialty markets.

The 1992-1993 pilot program was conducted with the assistance of the Alberta Oil Sands Technology and Research Authority, which committed to provide $300,000 for the program. The company believes the pilot program has been successful and is now directing its efforts towards establishing a commercial operation in the Athabasca region for production of bitumen and metals from existing tailings.

STEEPANK PILOT PROJECT – Chevron Canada Resources (T-600)

Chevron Canada Resources has started a new pilot project utilizing the HASDrive (Heated Annulus Steam Drive) process to recover bitumen from the Athabasca Oil Sands. The pilot plant is located on Chevron's Steepbank oil sands lease located about 30 miles northeast to Fort McMurray, Alberta, Canada.

In the HASDrive process, a horizontal wellbore is drilled into the oil sands formation. Steam is circulated in the cased wellbore thereby transferring heat into the oil sand. Two vertical injection wells are used to inject steam into the formation at points along the heated horizontal channel (annulus), driving the heated bitumen toward a production well placed between the injection wells.

The pilot includes two steam injection wells, one producing well, one horizontal HASDrive well, six temperature observation wells and four crosshole seismic wells.

Operations commenced November 1, 1991 with steam circulation in the horizontal well. Steam injection and production were both under way by March 1992. The project operations were suspended in March 1993.

Project Cost: $12.7 million

TACIUK PROCESSOR PILOT – AOSTRA and The UMA Group Ltd. (T-610)

UMATAC Industrial Processes (UMATAC) of Calgary, Canada developed the AOSTRA Taciuk Process (ATP) technology which is a patented, unique, thermal desorption system for separating and extracting water and organics from host solids. It was developed as a dry, thermal process to produce oil from natural resource oil sands and oil shales.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

The technology is owned by the Alberta Oil Sands Technology and Research Authority (AOSTRA), which funded the development since 1977, investing approximately $25 million. UMATAC is the developer and supplier, and also the licensee for use of the ATP System in waste treatment applications.

In 1992, AOSTRA convened an oil industry Task Force to re-assess the ATP for commercial production of oil from Alberta oil sand. The study included demonstration operation of a new, 5 tph capacity portable ATP plant operated by UMATAC in Calgary. Successful conclusions will lead to consideration of a large scale demonstration ATP plant installation in the Fort McMurray oil sands area of Alberta.

UMATAC has completed preliminary design of a 250 tph capacity ATP Processor and associated plant for an oil shale development project in Australia. Study and development of the ATP for this project included pilot scale testing of a 2,000 tonne bulk sample of oil shale shipped from Australia to the ATP pilot plant in Calgary. Testing was completed in 1987. This project is at the financing and final approvals stage, as of February 1994.

The ATP is also suited for use in treating contaminated soils, sludges and wastes in environmental remediation work. Typical applications are:

- Cleaning and recovering oil from wastes produced in oil field production and operations of oil refineries and petrochemical plants;
- Clean up of soils or other materials which are contaminated with PCBs or other heavy organic compounds, such as coal tars and industrial chemicals.

Organics and water are separated by anaerobic thermal desorption as vapors which are condensed to liquids in a second step of the system. The oil fraction is potentially recyclable, depending on the type of contaminant.

UMATAC supplies the ATP technology under license for use in waste treatment and also manufactures and supplies the ATP plant equipment. The ATP has been used commercially on soils remediation in the United States since 1990 by the U.S. licensee, SoilTech ATP Systems, Inc. A 10 tph capacity plant has successfully completed PCB clean up of two Superfund sites, and is beginning work on two others in 1993.

Project Cost To Date: C$24 million (AOSTRA)

TANGLEFLAGS NORTH – Sceptre Resources Limited and Murphy Oil Canada Ltd. (T-620)

The project, located some 35 kilometers northeast of Lloydminster, Saskatchewan, near Paradise Hill, involves the first horizontal heavy oil well in Saskatchewan. Production from horizontal oil wells is expected to dramatically improve the recovery of heavy oil in the Lloydminster region.

The Tangleflags North Pilot Project is employing drilling methods similar to those used by Esso Resources Canada Ltd. in the Norman Wells oil field of the Northwest Territories and at Cold Lake, Alberta. The combination of the 500-meter horizontal production well and steamflood technology is expected to increase recovery at the Tangleflags North Pilot Project from less than one percent of the oil in place to up to 50 percent.

The governments of Canada and Saskatchewan provided $3.8 million in funding under the terms of the Canada-Saskatchewan Heavy Oil Fossil Fuels Research Program.

Estimates indicate sufficient reserves exist in the vicinity of the pilot to support commercial development with a peak gross production rate of 6,200 barrels of oil per day. Project life is estimated at 15 years.

The Tangleflags pilot has advanced to the continuous steam injection phase. With one horizontal well and four vertical steam injection wells in place, the project was producing at rates in excess of 1,000 barrels of oil per day by mid 1990. Cumulative production to the middle of 1990 was 425,000 barrels. The expansion of the pilot project into a commercial operation involving up to 14 horizontal wells will hinge on future crude oil prices.

The strong performance of the initial well prompted Sceptre to initiate a project expansion which was completed during 1992. For this purpose a second horizontal producer well and an additional vertical injector well were drilled in the fourth quarter of 1990. Facilities were expanded to generate more steam and handle increased production volumes in early 1991. During 1992, two steam injectors were added and a third steam generator was brought into service. A peak project rate of 2,800 barrels per day was achieved in January 1993, and cumulative oil production reached 2,257 million barrels. As of mid-February 1993, an additional steam injector and another horizontal well had been drilled. The project now includes three horizontal producers and eight vertical steam injectors.

Project Cost: $13 million invested to 1993
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since December 1993)

R & D PROJECTS (Continued)

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


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 600 meters.

Two processes were selected for initial testing: steam assisted gravity drainage (SAGD), and Chevron's proprietary HASDrive process. Steaming of both test patterns commenced in December 1987 and continued up to early 1990. HASDrive was shut in April 1990 and the SAGD was to continue producing in a blowdown phase until the fall of 1990.

Both tests were technical successes. In the case of the Phase A SAGD test, a commercially viable combination of production rates, steam/oil ratios, and ultimate recovery was achieved. Complete sand control was demonstrated, and production flowed to surface for most of the test.

Construction of the Phase B SAGD test commenced in the spring of 1990 with the drivage of 550 meters of additional tunnel, for a total of about 1,500 meters. Phase B is a direct scale up of the Phase A test, using what is currently thought to be the economic optimum well length and spacing. The test consists of three pairs of horizontal wells, with completed lengths of 600 meters and 70 meter spacing between pairs. Each well pair consists of a producer placed near the base of the pay, and an injector about 5 meters above the producer. All six wells were successfully drilled in 1990/1991. The contractual obligations for Phase B operations will be completed by 1994. It is expected that Phase B will continue operation until 1996. Phase A produced over 130,000 barrels of bitumen.

Phase B steaming commenced in September 1991, then was shut-in temporarily to construct larger facilities. Production was started up in early 1993. A decision regarding expansion to commercial production will be made after evaluation. Two thousand barrels per day of bitumen are expected to be produced by this method. During June 1993, one well, BP-2, averaged 630 barrels per day.

AOSTRA states that this new method of bitumen production is a major technological breakthrough and that bitumen may eventually be produced for under C$7 per barrel, which would be less costly than most current in situ bitumen production.

In 1992 an agreement was reached with Syncrude Canada to process up to 2,000 barrels per day of bitumen through Syncrude's nearby upgrading facilities.

Project Cost: $150 million

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PROJECT ACTIVITIES

ENCOAL PLANT STARTS UP AGAIN

SGI International reported in January that the ENCOAL Clean Coal demonstration plant near Gillette, Wyoming, has resumed operations and its testing programs following the completion of plant improvements and installation of additional equipment. The purpose of the modifications was to enhance plant reliability and production of marketable processed coal and oil coproducts. The processed coal is to be supplied to utilities for powerplant test burns; the oil is contracted for sale to industrial customers.

The plant uses the Liquids From Coal (LFC) Process, originally developed by SGI International. The LFC Process is designed to upgrade low-rank coals into both low-sulfur processed coal and coal liquids similar to No. 6 fuel oil.

The United States Department of Energy and the ENCOAL Corporation are cofunding $72.6 million for this project under the Clean Coal Technology Demonstration Program.

###

ADVANCES MADE IN SHELL-BASED IGCC PLANT DESIGN

The Shell Coal Gasification Process (SCGP) is a dry-feed, oxygen-blown, entrained flow coal gasification process which has the capability to convert virtually any coal into a clean medium-BTU synthesis gas. The SCGP syngas is predominantly carbon monoxide and hydrogen and has a multitude of uses, including fuel for combined cycle power generation, hydrogen for refining applications, feedstock for the manufacture of chemicals such as ammonia and methanol, and feedstock for the direct synthesis of conventional transportation fuels using technologies such as the Shell Middle Distillate Synthesis Process.

Technology improvements in the SCGP were described in a paper by E.L. Doering and G.A. Cremer of Shell. The paper was presented at the 12th Electric Power Research Institute Conference on Gasification Powerplants, held in San Francisco, California in October.

In SCGP, high pressure nitrogen or recycled syngas is used to pneumatically convey dried, pulverized coal to the gasifier. The coal enters the gasifier through diametrically opposed burners, where it reacts with oxygen at temperatures in excess of 2,500°F. The gasification temperature is maintained sufficiently high to ensure that the mineral matter in the coal is molten and will flow smoothly down the gasifier wall and out the slag tap. Gasification conditions are optimized, depending on coal properties, to achieve the highest coal to gas conversion efficiency, with minimum formation of undesirable byproducts.

The hot syngas exiting the gasifier is quenched to below the softening point of the slag and then cooled further in the syngas cooler. Entrained flyash is removed to less than 1 ppm using ceramic candle filters. Downstream syngas treating includes low-level heat recovery and conventional cold gas cleanup to remove sulfur and nitrogen compounds. Essentially all of the nitrogen is ultimately converted to molecular nitrogen, and essentially all of the sulfur is recovered as salable, elemental sulfur. Slag and flyash are also recovered as marketable byproducts.

An important element in the SCGP development program was the construction and operation of SCGP-1, a 250-ton per day demonstration unit which operated between 1987 and 1991.

Data collected during the SCGP-1 operating program yielded a number of process improvements and innovations which have since been incorporated into commercial designs.

Demkolec Project

The first commercial application of SCGP is the Demkolec project, a 253-megawatt Integrated Gasification Combined Cycle (IGCC) powerplant located in The Netherlands.

The Demkolec project, which was scheduled to begin operations in late-1993, employs a single SCGP gasifier to fuel a Siemens V94.2 combustion turbine coupled with a steam turbine and generator. The SCGP plant is fully integrated with the combined cycle plant, including the boiler feed water and steam systems; in addition, the compressed air for the high pres-
sure air separation unit is totally supplied by extraction air from the combustion turbine air compressor.

The Demkolec project features a multiple burner gasifier scaled up from the SCGP-1 gasifier to 2,000 tons per day coal. Also, the Demkolec project includes a number of process improvements which were successfully demonstrated during SCGP-1 operation. Among these are:

- Dry solids removal which offers higher flyash removal efficiency and lower cost
- Flyash recycle to improve carbon conversion and slagging efficiency
- Flux addition to promote slag flow and optimize gasification conditions, depending on coal properties
- Catalytic hydrolysis of hydrogen cyanide and carbonyl sulfide to reduce corrosion, reduce emissions and simplify gas treating
- Zero aqueous process discharge for environmental considerations

- A turbine lead/gasifier follow control system for load following

Shell Synthetic Fuels' SCGP Commercial Design

The SCGP commercial design is the latest effort by Shell Synthetic Fuels Inc. to combine SCGP technology developments subsequent to the SCGP-1 program and the Demkolec project design with other related IGCC improvements. A flow schematic of the SCGP commercial design is shown in Figure 1. The design is based on a single-train SCGP plant coupled with a high-pressure air separation unit to fuel a single combustion turbine operating in combined cycle service. If the General Electric Frame 7FA combustion turbine is used, IGCC net power output is estimated to be approximately 265 megawatts. With a high sulfur Illinois coal, the heat rate is estimated at slightly less than 8,150 BTU per kilowatt-hour. Even lower heat rates can be expected with most other bituminous coals.

Technology improvements in the SCGP design, which contribute to lower costs, higher efficiency and reduced emissions compared to earlier designs, include the following:

**FIGURE 1**

**SHELL COAL GASIFICATION PROCESS**

*Source: Doering and Cremer*
A more compact gasifier design, aimed at reducing capital cost and increasing coal to gas conversion efficiency

- Revised syngas cooler design to reduce capital costs and maintenance requirements
- Continuous flyash letdown to improve reliability and reduce maintenance requirements
- Dry chloride removal to further simplify downstream gas treating
- Techniques to increase efficiency and reduce formation of undesirable byproducts in the gasifier
- Methods for improved removal and recovery of volatile metals such as mercury and arsenic to reduce hazardous air pollutants emissions
- Integration of SCGP with the combined-cycle and air separation units to minimize dollars per kilowatt cost, while maintaining performance and operability requirements

Each of the main systems associated with a Shell-based IGCC plant is briefly discussed below.

Coal Pulverizing and Drying

The SCGP commercial design includes two large commercial-scale pulverizers for a single gasifier/gas turbine train. Each pulverizer has excess capacity so that sufficient availability is provided without the need for an additional pulverizer. Heat and nitrogen savings have also been designed into the drying system for higher moisture content coals.

SCGP Gasifier

Engineering studies led to a more compact gasifier design, while at the same time leading to increased syngas production. Gasifier materials' life is extended by operating the gasifier cooling medium at lower pressure.

Syngas Cooling and Dry Solids Removal

- The SCGP commercial design uses a dust laden, raw gas firetube exchanger downstream of the conventional recycle gas quench section, followed by dry flyash removal.

Dry Chloride Removal

Studies indicate that a dry chloride removal technique with a sorbent can be a more cost effective technique than washing out the chloride. Dry chloride removal offers the additional advantages of reducing catalyst poisons for downstream catalyst beds and of allowing more low-level heat recovery from the raw gas.

Cold Gas Cleanup

High sulfur removal efficiencies are achievable with the SCGP cold gas cleanup system, according to Doering and Cremer. Either of two Shell solvents can be used to hydrolyze trace amounts of carbonyl sulfide in the syngas to hydrogen sulfide and then remove the hydrogen sulfide through absorption. In the SCGP commercial design a proprietary system for removing volatile metals such as mercury and arsenic has been combined with the SCGP cold gas cleanup system to further reduce emissions of hazardous air pollutants.

Integration of SCGP With Combined Cycle and Air Separation Units

The General Electric 7F and the Westinghouse 501F gas turbines provide high fuel gas-to-electricity generating efficiency and improved combined cycle performance. The increased gas turbine performance has served to increase net IGCC power output, which has in turn helped to reduce the IGCC dollars per kilowatt cost. Additional IGCC cost and performance benefits can be realized through careful integration of the three basic technologies--SCGP, air separation, and combined cycle power generation. Figure 2 illustrates a highly integrated Shell-based IGCC powerplant.

Environmental Attributes

Environmental emissions of Shell-based IGCC are estimated to be extremely low. Total SO\textsubscript{2} emissions of 0.05 pounds per million BTU or less are achievable, corresponding to greater than 99.5 percent sulfur removal efficiency, according to Doering and Cremer. NO\textsubscript{x} emissions can be controlled to 0.09 pounds per million BTU (corresponding to 25 ppmv in the heat recovery steam generator flue gas) or less, and hazardous air pollutant emissions as defined in the Clean Air Act Amendments of 1990 are expected to be less than
0.5 tons per year for a nominal 265-megawatt Shell-based IGCC plant. As shown in Figure 3, the estimated air emissions from a Shell-based IGCC powerplant are well below the regulatory limits and in fact are much closer to those from a natural gas-fired powerplant than from a typical coal-based facility. Moreover, long-term, on-site storage of solid byproducts is not required, because slag, flyash and elemental sulfur are all marketable products.

GROUNDBREAKING SET FOR 2-MEGAWATT MOLTEN CARBONATE FUEL CELL

The participants in the Santa Clara Demonstration Project in January announced April 7, 1994, as the date for groundbreaking on the world’s first demonstration of a 2-megawatt carbonate fuel-cell powerplant located in Santa Clara, California.

Construction of the facility is expected to be completed by the end of 1994, followed by facility check-out and stacks installation by April 1995. The 2-year powerplant demonstration will follow after acceptance testing.

According to project sponsors, fully commercial carbonate fuel-cell powerplants could be introduced in the 1998-1999 timeframe.

A commercial price of $1,000 per kilowatt (1990 dollars) is projected.

GREAT PLAINS PROJECT BUILDING SCRUBBERS FOR COAL LOCK VENT GASES

The Basin Electric Power Cooperative reported in January that 14 coal lock vent scrubbers for the Great Plains Synfuels Plant are being fabricated.

The scrubbers are part of a permit issued in March 1993 by the North Dakota Health Department for reducing emissions at the plant. The scrubbers weigh about 15 tons each, and are designed to remove coal particles and reduce odors from the vent gas emissions.
These scrubbers will be installed on each of the 14 gasifiers, about 70 feet up in the gasifier building.

Also part of the permit is the designation of a wet scrubber system as the best available control technology for removing sulfur dioxide from flue gas in the plant's main stack.

The coal lock vent scrubbers must be operating within 2 years and the main stack scrubber in 4 years.

The cost for the project is $105 million.

HEALY CLEAN COAL PROJECT HITS SNAG

In January, Anchorage Superior Court Judge M. Souter granted a request by environmental groups to put on hold a state operating license issued to the planned Healy Clean Coal Project. (See the Pace Synthetic Fuels Report, December 1993, page 4-4.) An appeal is pending before the Alaska Supreme Court.

Souter gave no reasons why he approved the stay on the license issued by the Alaska Public Utilities Commission. The order came 2 months after Souter upheld the Alaska Public Utility Commission's decision to grant the license to the Alaska Industrial Development and Export Authority. Opponents of the plant appealed that finding to the Supreme Court in December.

Views on the significance of the stay order were mixed, particularly on whether it would or should have an impact on plans to begin construction in May.

Both the Alaska Public Utility Commission and the Alaska Industrial Development and Export Authority, which is funding about one-third of the project, said the stay order does not mean much because it is an operating license, not a building permit.

A representative of Trustees for Alaska, an Anchorage-based environmental law firm, said that it would be prudent to reassess construction plans until the problems were resolved.

The clean coal project already has been approved by the state Department of Environmental Conservation, National Park Service and the United States Department of Energy (which completed an Environmental Impact Statement on the project in December).

TVA CANCELS WORK ON COPRODUCTION POWER AND FERTILIZER CONCEPT

A Tennessee Valley Authority (TVA) coal gasification facility that would have produced power and fertilizer as coproducts has been canceled.

Attempts to obtain funding through the United States Department of Energy Clean Coal Technology Program were not successful.

TVA says it will continue to evaluate coproduction and coal refining technologies in order to use the higher value of chemical coproducts to reduce/subsidize the cost of electricity. However, there is no active effort at the present time.

WESTERN ENERGY SYNCOAL PROCESS MAY FIND A CUSTOMER

In late December, Minnkota Power Cooperative signed a letter of intent with Rosebud SynCoal Partnership for a $2 million study to examine the merits of scaling up the latter's technology to an $80 million commercial plant.

The SynCoal plant would be sited next to Minnkota's Milton R. Young power station near Center, North Dakota, northwest of Bismarck. The engineering and design study would be completed in mid-1994.

The agreement for the engineering study was based on the success of 7 months of tests at a smaller, first-of-a-kind plant in Colstrip, Montana operated by Western Energy.

The process boosts the heating value of lignite by 60 percent while cutting its sulfur content by 50 percent. The technology reduces moisture in low-rank coals such as lignite by first removing loosely held surface water by heating the coal to about 600°F in a vibrating fluid-bed vessel.
Next the coal is heated to about 900°F in a second vibrating bed to remove chemically bound water, carboxyl compounds and volatile sulfur compounds.

Treated coal then is cooled by an inert gas in a vibrating fluid-bed vessel. Last, vibrating screens and fluid-bed separators remove additional sulfur and other minerals.

###

CARBONATE FUEL CELL BEING TESTED IN SLIPSTREAM AT DESTEC GASIFICATION FACILITY

The Electric Power Research Institute has sponsored a 30-kilowatt carbonate fuel-cell pilot plant at Destec Energy's coal gasification plant in Plaquemine, Louisiana.

This project was discussed in a paper by D.M. Rastler and C.G. Keeler, presented at Power-Gen '93 Americas, held in Dallas, Texas in November.

The primary objective of this project is to complete a 4,000-hour endurance test with a 30-kilowatt carbonate fuel cell and to demonstrate the compatibility of the carbonate fuel cell operating on actual syngas. Other project objectives are as follows:

- Endurance test a 20-kilowatt carbonate fuel cell for 4,000 hours
- Assess effects of syngas contaminants
- Gain design and operating experience on syngas
- Identify MW design issues and research and development needs

The project sponsors approved funding for the following five tasks:

- Task 1: Concept design and budget estimates
- Task 2: Final design, fabrication and installation
- Task 3: Endurance testing on syngas
- Task 4: Post test analysis and reporting
- Task 5: Preliminary design of an integrated megawatt carbonate fuel cell

Tasks 1 and 2 have been completed and Task 3 (endurance testing) is currently under way. The two final tasks will not be completed until 1994. It is probable that results from Task 5 will be used in the construction and operation of a more integrated multimegawatt facility that would be the next step toward commercialization of fuel-cell powerplants operating on syngas.

Facility Description

The fuel-cell facility is interfaced with a 160-megawatt coal gasification plant where the Destec process is being commercially demonstrated. The Destec coal gasification process uses a pressurized, entrained flow, slagging, slurry-fed gasifier with a continuous slag removal system. The gasification process produces a sweet syngas that has an energy value of approximately 250 BTU per standard cubic foot. A 100-pound per hour slipstream of the sweet syngas is supplied to the fuel-cell facility. The facility can test fuel-cell modules from 20 kilowatts to 100 kilowatts in capacity, on either natural gas or coal-derived gases.

In the pilot facility (Figure 1), E-101 preheats the sweet syngas to the operating temperature required in R-101. Beds of alumina and zinc oxide in R-101 chemically absorb the trace chlorine and sulfur compounds to levels less than 0.1 ppm. Next, steam is added to the desulfurized syngas to facilitate the water-gas shift reaction and E-104 further heats the gas and steam mixture before it enters the fuel cell. The preconverter, R-102, is only used during natural gas operation to crack higher hydrocarbons to methane and hydrogen.

Next, the syngas enters the fuel cell and, similar to a battery, the chemical energy of the fuel is converted to DC power. In the anode approximately 70 percent of the fuel reacts to CO₂ and water. Unreacted fuel is combusted in the anode offgas burner, H-101, with an excess of air supplied by the combustion air blower, K-101. Additional fuel from R-101 is supplied to H-101 to maintain stable firing. The gas from H-101 re-enters the fuel cell, where the oxygen and CO₂ react at the cathode to regenerate the carbonate ions in the electrolyte that were consumed at the anode. The depleted oxidizing gas exits the cathode chamber and is vented to the atmosphere.
The fuel-cell stack incorporates state-of-the-art internal reforming technology that converts natural gas to hydrogen. The stack is designed to operate on natural gas or syngas. The stack consists of 54 (2-foot by 3-foot) cells that are each three-eighths inch thick and stacked one on top of the other to build up voltage. The unit operates at atmospheric pressure and 1,200°F. This stack includes lightweight end-plates to reduce weight and to improve thermal management (heat loss), double electrical insulation from the stack to further improve safety, and a vessel enclosure to protect the stack from the environment and to ease handling and shipping.

Natural gas testing was performed to ensure that the fuel cell was not adversely affected during transit and installation. The fuel cell was subsequently started up on syngas. Performance data for syngas operation were not available at the time of publication.

###
PROOF-OF-CONCEPT LIQUEFACTION FACILITY DEDICATED AT HRI

The Coal Liquefaction Proof-of-Concept Facility was dedicated in August at the Hydrocarbon Research, Inc. (HRI), Research Center in Lawrenceville, New Jersey.

The $33 million, 5-year, cost-shared contract was awarded in September 1992, and work began immediately to modify the existing 3-ton per day process development unit. In 1992, the United States Department of Energy decided to close a large test facility in Wilsonville, Alabama, and chose the smaller, less costly, and more flexible HRI facility.

The modifications are intended to improve the reliability of the unit and enable it to function in several additional process configurations. Changes have been made in automation, computer controls, and the electric power supply. The Kerr-McGee-Rose-SR unit from Wilsonville was resized and installed to allow a direct comparison between the U.S. Filter Fluid Systems Corporation system for solids separation and the Rose-SR critical solvent de-ashing process. Reactors and ebullating pumps were also installed, which should allow additional flexibility for multi-state systems. An in-line hydrotreater should allow the production of higher-quality, environmentally acceptable, liquid fuels.

Research at the facility is focusing on advancing liquefaction technology development through the two-stage liquefaction, coprocessing, and advanced concept processes. Efforts are under way to improve the economics of the processes by using strategic feedstocks, commercially feasible catalysts, prototype equipment, and improved construction materials.

The first run, which was recently completed, used Illinois No. 6 coal. Results of the run are not yet available.
Today, the status of the active coal conversion-related projects in the Clean Coal Technology Program is as follows (see Figure 1 for an overall schedule of the Clean Coal Technology Program):
Rosebud SynCoal Partnership - Advanced Coal Conversion Process Demonstration

The Advanced Coal Conversion Process Demonstration facility underwent a complete maintenance turn around from June 6 to August 13, 1993 which re-established dual-train operation. Also, a new fines conveying, cooling and loadout system was installed. Shipments of the upgraded "SynCoal" product to several Midwest utilities and industrial customers are being made for handling tests and test burns. Since tests began, the plant has processed more than 160,000 tons of raw coal and is now operating at full capacity.

ABB Combustion Engineering - IGCC Repowering Project

Efforts continue to address the high capital cost projection for the project.

Air Products and Chemicals, Inc. - Liquid Phase Methanol Process

DOE approved Eastman Chemical Company's integrated coal gasification facility as an alternative host site on October 8, 1993. Project definition activities are under way.

Alaska Industrial Development Authority - Healy Clean Coal Project

Engineering and permitting efforts are proceeding. TRW completed combustor design verification testing in March, successfully firing a full-scale precombustor module using a newly designed coal feed system. DOE issued the final Environmental Impact Statement (EIS) on December 15, 1993.

ENCOAL Corporation - Mild Gasification Project

The plant has been shut down in order to complete major modifications to the solids cooling system, rotating grate seals, water slurry fines handling system, and feed coal and solid product conveying systems. The plant is scheduled to resume operation in early January.

Tampa Electric - Integrated Gasification Combined Cycle Project

State of Florida hearings on the permits for the plant were held on October 13. No dissenting opinions from either state or county representatives were voiced. A second draft of the EIS has been completed and comments have been returned to the Environmental Protection Agency (the lead agency for EIS).

TAMCO Power Partners - Toms Creek IGCC Demonstration Project

Project definition and preliminary design activities are underway. A power purchase agreement is being sought.

ThermoChem, Inc. - Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

A preliminary design of the ThermoChem coal gasification demonstration plant integrated with the host K-Fuel facility was completed in April 1993. Test gasification of the design coal is under way at ThermoChem's Baltimore, Maryland facility.

Sierra Pacific Power - Pinon Pine IGCC Project

The Public Service Commission of Nevada approved the project on October 25. A draft EIS is being prepared by DOE.

Wabash River Joint Venture - Wabash River Coal Gasification Repowering Project

Project design is approximately 90 percent complete. Site preparation work has been finished and construction is under way. Major equipment procurement is in progress. Design, supply, and erection contracts for steel support towers, data acquisition system, and coal handling system were awarded in September.

####
ENERGY POLICY AND FORECASTS

$25 BILLION IN GASIFICATION PROJECTS ALREADY COMMITTED

More than 63 coal gasification projects are now in the planning and construction phases worldwide, according to a report by The McIlvaine Company. This represents a commitment of over $25 billion dollars in initial capital costs. The 250-megawatt Shell gasification project in Buggenum, The Netherlands is presently in the start-up stage. The Destec Energy entrained bed gasification process is in the construction stage (a 260 megawatt plant for PSI Energy in Terre Haute, Indiana). The 220-megawatt Polk integrated gasification combined cycle power station at Tampa Electric is slated for initial construction in the second quarter of 1994.

Not all gasifiers will be used to produce electricity. Eastman Chemical in Kingsport, Tennessee will demonstrate the use of gasifiers to produce methanol. The product will be tested in buses and van pools.

Of the 63 projects noted, 55 are designed for electricity production and will provide in excess of 16,000 megawatts. Eight projects are for chemical production with an equivalent output of 4,200 barrels per day. Six new projects have recently been added to the McIlvaine list, including one project in Italy, two in China and one in India. This brings the total of planned projects in China to seven, ranking it only behind the United States, where fifteen projects are slated.

McIlvaine forecasts that the investment in coal gasification facilities worldwide will exceed over $100 billion dollars in the next decade. The largest investment will be in North and South America, followed by Asia and then Western Europe.

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SYNTHETIC FUELS REPORT, MARCH 1994

4-11
ECONOMICS

MITRE FINDS DIRECT LIQUEFACTION MORE ECONOMICAL THAN INDIRECT

MITRE Corporation has studied the technologies for producing liquid transportation fuels from coal and traced their evolution. How their economics have changed with continuing research and development was also evaluated. Results were presented in a paper by D. Gray, et al., at the 10th Annual International Pittsburgh Coal Conference, held in Pittsburgh, Pennsylvania in September.

For direct liquefaction, coal is slurried with a recycle oil and heated under high pressure hydrogen to produce a synthetic crude oil that must be further refined into specification transport fuels. The hydrogen required for this process can be produced by gasification of coal and residue or by natural gas steam reforming. During liquefaction, synthesis gas is passed over Fischer-Tropsch (F-T) or other catalysts where a series of hydrocarbons ranging from C₁ to about C₂₀₀ is produced along with varying amounts of oxygenates. These raw products must be refined to produce specification fuels.

Research conducted over the last 15 years has led to the development of a catalytic two-stage liquefaction process, which uses two high pressure ebullating bed reactors in series to solubilize coal and upgrade it to a distillate raw product.

Economics

MITRE has been developing computerized simulation models of coal liquefaction technologies for several years. In these models, test data from ongoing research and development are used to develop conceptual commercial plants for both direct and indirect coal liquefaction. Construction, capital and operating costs of the plants are estimated. The required selling prices of liquid fuels are calculated based on a constant set of economic parameters.

Results obtained by using the simulation models to develop conceptual commercial plants for direct and indirect coal liquefaction are summarized in Table 1. Both plant use the current state-of-the-art technology. The direct liquefaction example is based on Wilsonville Run 2581 with Black Thunder subbituminous coal as feed. The plant is sized to produce about 70,000 barrels per day of hydrotreated liquid product.

For direct liquefaction, coal is used for both the liquefaction reactors and for gasification to produce the hydrogen.

For the indirect commercial plant example, Shell gasification is used to gasify Illinois #6 coal to produce synthesis gas, which is purified and passed to slurry phase F-T reactors, where raw F-T products are produced. Performance data for the slurry F-T reactor are taken from results obtained by Mobil. The products are refined in a dedicated F-T refinery to give high quality finished gasoline and diesel fuel. The indirect plant produces about 44,000 barrels per day of gasoline and diesel. The alcohols produced are valuable octane enhancing additives to the gasoline pool.

The results show that products from direct liquefaction have a lower required selling price ($40.01 per barrel) than products from indirect liquefaction ($45.60 per barrel).

Earlier MITRE studies of the economics of direct coal liquefaction have shown that the current two-stage configuration can produce liquids at a required selling price about 25 percent lower than early single-stage processes such as EDS and H-Coal. HRI and other research organizations are investigating novel advanced concepts that have the potential to further reduce the cost of liquid fuels from direct coal liquefaction.

For indirect liquefaction, the development of improved entrained coal gasification and advanced slurry F-T synthesis has reduced the required selling price of gasoline and diesel from coal by about 28 percent compared to the conventional SASOL plants that use Lurgi gasifiers and Synthol circulating bed F-T reactors. The SASOL plants produce large quantities of methane and ethane from the gasifiers and the F-T units. This gas must be reformed back into synthesis gas with considerable efficiency and cost penalties. However, the combination of high efficiency gasifiers and high conversion per pass F-T reactors produces little methane and ethane and allows liquids rather than hydrocarbon gas to be preferentially produced. Producing and selectively hydrocracking wax to yield distillate, circumvents the Schulz-Flory probability distribution of hydrocarbon products and greatly improves the liquid selectivity from the overall F-T process. Continued research to
TABLE 1
SUMMARY DATA FOR CONCEPTUAL COMMERCIAL
COAL LIQUEFACTION PLANTS

<table>
<thead>
<tr>
<th></th>
<th>Direct (CTSL Process) (Wyoming Coal)</th>
<th>Indirect (Shell Gasification Slurry F-T) (Illinois #6 Coal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Input (Tonnes per Day)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal to Liquefaction</td>
<td>16,634</td>
<td>-</td>
</tr>
<tr>
<td>Coal to Gasification</td>
<td>3,869</td>
<td>16,440</td>
</tr>
<tr>
<td>Total Plant Coal</td>
<td>20,503</td>
<td>16,440</td>
</tr>
<tr>
<td>Output (BPSD)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alcohols</td>
<td></td>
<td>1,197</td>
</tr>
<tr>
<td>C$_3$/C$_4$ LPG</td>
<td>788</td>
<td>5,985</td>
</tr>
<tr>
<td>C$_5$-450°F (Gasoline)</td>
<td>34,331</td>
<td>20,804</td>
</tr>
<tr>
<td>450-650°F (Diesel)</td>
<td>21,084</td>
<td>23,178</td>
</tr>
<tr>
<td>650-850°F</td>
<td>7,933</td>
<td>-</td>
</tr>
<tr>
<td>Total Raw Product/Product</td>
<td>63,348</td>
<td>51,165</td>
</tr>
<tr>
<td>Total Hydrotreated Product</td>
<td>69,814</td>
<td>-</td>
</tr>
<tr>
<td>Overall Thermal Efficiency (HHV%)</td>
<td>66</td>
<td>59</td>
</tr>
<tr>
<td>Barrels Gasoline/Diesel per ton of MAF Coal</td>
<td>3.41</td>
<td>2.68</td>
</tr>
<tr>
<td>Economic Data</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Cost ($MM)</td>
<td>2,123</td>
<td>1,943</td>
</tr>
<tr>
<td>Total Capital</td>
<td>3,305</td>
<td>2,982</td>
</tr>
<tr>
<td>Net Operating Cost</td>
<td>374</td>
<td>217</td>
</tr>
<tr>
<td>Required Selling Price</td>
<td>40.01</td>
<td>45.60</td>
</tr>
<tr>
<td>Hydrocracked Product (Gasoline/Diesel) $/Bbl</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Improve the performance of the slurry reactor and development of improved, more active F-T catalysts will further reduce the costs of liquid transportation fuels from indirect coal liquefaction in the future.

Direct liquefaction produces a hydrotreated product that must undergo additional refining, either in an existing petroleum refinery or at the liquefaction site to produce finished transportation fuels. Research conducted by Chevron in the 1980s on refining of liquids from the EDS, H-Coal, and early two-stage processes showed that direct coal liquids could be used to produce high quality transportation fuels by using hydro treating and hydrocracking processes at various degrees of refining severity. The indirect plant simulated in this analysis produces finished gasoline and diesel. The reason for this is that the simulation model includes a dedicated F-T refinery where the raw F-T products are upgraded, by using polymerization of the light olefin gas, mild hydrotreatment of the liquid, reforming of the naphtha, and hydrocracking of the wax. The resulting gasoline and diesel could either be used as fuels directly or as a blending stock with petroleum fuels.

The differences in the product characteristics of direct and indirect liquefaction make the two processes complementary. The paraffinic indirect naphtha can be blended with the aromatic direct naphtha to minimize the amount of refining required. Similarly, the aromatic diesel from direct liquefaction can be blended with the paraffinic diesel from indirect. Thus, MITRE concluded that a hybrid plant concept in which both direct and indirect technologies are sited at the same location may have considerable merit.

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SYNTHETIC FUELS REPORT. MARCH 1994
IGCASH CYCLE SHOWS PROMISE FOR INTERMEDIATE LOAD APPLICATIONS

Bechtel has assessed the technical and economic merits of the Integrated Gasification Compressed Air Storage with Humidification (IGCASH) power cycle. Performance and cost data were developed for a generic IGCASH plant in the 400- to 500-megawatt size range that can serve as a stand-alone, intermediate-load, coal-based powerplant.

This study was discussed by O.F. Ghaly, et al., in a paper presented at the 12th Electric Power Research Institute Conference on Gasification Powerplants, held in San Francisco, California in October.

The IGCASH concept combines features of Compressed Air Energy Storage (CAES), air humidification, and coal gasification. A simplified schematic of the concept is shown in Figure 1. The plant contains both cycling and continuously operating components:

- Cycling components include an air compressor, hot water storage tanks that store compression thermal energy recovered by compressor intercoolers and aftercoolers, and an underground air storage cavern.

- Continuously operating components include a saturator to warm and humidify air from the cavern, a quench-type coal gasification system to produce fuel gas, a reheat turboexpander train, and a recuperator-economizer system to recover heat from the turbine exhaust gas.

In operation, the IGCASH plant spends the off-peak period in a charging mode and the peak period of the day in a discharging mode. In the charging mode, all of the net electric power generated by the plant is used to compress air to charge the cavern. In the discharging mode, the compressor is turned off, and all of the net power is exported to the grid.

FIGURE 1
SIMPLIFIED IGCASH CYCLE
Advantages of the IGCASH as an energy storage concept compared to conventional CAES include the following:

- Humidification raises the air mass flow, thus reducing the compressor energy consumption, charging period, and air storage cavern size.

- Humidification also preheats the combustion air, thus reducing fuel consumption and increasing efficiency.

- The heat of compression is recovered and reused for humidification, thus increasing the overall cycle efficiency.

- All high-temperature components (turbine, recuperator, and gasifier) operate 24 hours a day, leading to improved component reliability and plant availability.

Furthermore, Ghaly, et al., report that the IGCASH concept offers advantages over integrated gasification combined cycle as coal-based power generation technology for intermediate to baseload service:

- Operation at a higher cycle pressure, which improves compression and expander efficiencies.

- Nearly 50 percent more generation capacity is achieved for the same gasifier capacity, resulting in significant capital cost savings.

- A less-costly quench-type gasifier heat recovery design can be used, because no high pressure steam is needed in the power cycle.

- Combustion air leaves the cavern at ambient temperature, allowing for more effective use of the low-level heat sources in the gasification system.

**IGCASH Plant Design**

In the IGCASH plant chosen for evaluation, three plant systems, namely, air compression, air storage, and hot water storage, operate only during off-peak hours, while the rest of the plant operates continuously. The plant uses about 2,080 tons per day of coal feed, which is processed in a full-quench Texaco gasifier to produce a raw synthesis gas. The raw synthesis gas is subsequently scrubbed, cooled and desulfurized to produce a clean medium-BTU fuel gas feed for the power cycle. Air for the power cycle is first compressed to about 900 psia and is subsequently cooled, most of it is stored in an underground salt cavern. The rest is sent directly to a packed column, where it is heated and saturated with water before being expanded in a high pressure turbine. It is then reheated and expanded in a low pressure turbine. Part of the heat of compression is recovered in intercoolers while heating demineralized water, part of which is sent to storage. The rest of the heat is rejected to cooling water. Additional heat is recovered from the turbine exhaust gas in a recuperator and an economizer that heat the humid air leaving the saturator and the hot water leaving storage, respectively. During peak operating hours, the air and hot water from the air saturator are supplied from the cavern and hot water storage tanks, respectively. The plant exports about 410 megawatts of electricity to the grid during peak operating hours.

**Power Cycle Configurations and Options**

Energy Storage and Power Consultants and Bechtel analyzed, with the help of computer simulation, several cycle configurations and options with respect to their performance and cost within the overall plant design philosophy of trying to minimize the plant cost in dollars per kilowatt rather than maximize the efficiency. Cycle configurations and options studied included:

- Various air compressor train arrangements

- Various levels of compression heat recovery and several intercooler design configurations

- Whether to use a high pressure combustor ahead of the high pressure turbine

- Water storage temperatures ranging from 200 to 525°F

- Air humidification levels ranging from 24 to 40 percent moisture (by volume)

The result of the analysis showed that the low pressure turbine inlet temperature and the hot water storage temperature were the parameters that mostly affected the performance and cost. Also, cycle configurations
that minimized the fuel gas intake produced significant capital cost savings as they reduced the gasification plant size.

Finally, three cycle configurations were selected to represent three plant design cases covering a range of hot water storage temperature and turboexpander firing temperature. Most of the study effort was focused on developing a base case design and cost.

In addition to the base case cycle, two alternate cycle cases labeled A-1 and A-2 were developed and costed.

Plant performance results for the three study cases show clearly the effect of water storage temperature and turbine firing temperatures on the overall plant net heat rate, report Ghaly, et al. An increase in either or both temperatures reduces the heat rate and improves the overall plant efficiency. Coal consumption (and hence gasification plant size), however, increases as the hot water or turbine firing temperatures are raised. This is also reflected in the generation heat rate which tends to follow the coal consumption but does not account for the hours of power generation.

Capital costs, operating costs, and life-cycle levelized Cost Of Electricity (COE) were estimated for the base case and alternate cases.

The base case shows the lowest plant cost of about $1,200 per kilowatt, while Case A-1 yields the highest plant cost of about $1,350 per kilowatt. The higher water storage temperature used in Case A-1 proved to be quite costly due to the higher equipment costs of the intercoolers and water storage. The significantly higher power output of Case A-2 offset to some extent the higher costs associated with recovering and storing heat at 525°F and with using a larger gasification facility. This is reflected in the slightly lower plant cost of about $1,310 per kilowatt.

Constant-dollar levelized COE was determined for each case. In all cases, the IGCASH plant was assumed to operate at full capacity over the daily cycle. The COE for all cases is capital intensive. The 350°F water base case proved to be more economical than the 525°F water alternate Case A-1 (at approximately the same capacity factor), showing a COE of about 58.7 mills per kilowatt-hour. The advanced turbomachinery Case A-2 yields the lowest COE, mostly because of its significantly higher power output (as reflected in its maximum capacity factor), which more than offset it higher plant cost.

Comparison With Other Power Generation Technology

To confirm the merit of the IGCASH cycle as an option for using coal in intermediate-load service, the base case plant was compared to a modern Pulverized Coal-Fired Steam (PCFS) reference plant which incorporates special design features to facilitate cycling operation. The PCFS plant is equipped with flue gas desulfurization and selective catalytic reduction units for emissions control. The PCFS plant is assumed to operate on a two-shift daily cycle, generating electricity at full capacity for 13.5 hours and shutting down for 10.5 hours.

Table 1 (next page) provides a comparison between the IGCASH and the cycling PCFS plants. As shown, the IGCASH technology offers significantly better performance at noticeably lower costs.

###

BASELOAD POWER GENERATION TECHNOLOGIES COMPARED BY BLACK AND VEATCH

Technical, environmental and economic aspects of commercially available coal and natural gas-fueled generation alternatives which can be expected to provide baseload capacity in the year 2000 have been considered by Black and Veatch. The results were discussed by T.E. Kalin, et al., in a paper presented at Power-Gen '93 Americas, held in Dallas, Texas in November.

The following technologies will be available in the year 2000 to meet large baseload demands:

- Coal fueled
  - Pulverized coal (PC)
  - Atmospheric Fluidized Bed Combustion (AFBC)
  - Gasification Combined Cycle (GCC)
  - Pressurized Fluidized Bed Combustion (PFBC)
TABLE 1

IGCASH AND PCFS PLANT COMPARISON

<table>
<thead>
<tr>
<th></th>
<th>IGCASH Plant</th>
<th>Pulverized Coal Cycling Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Base Case</td>
<td></td>
</tr>
<tr>
<td>New Power Output (MWe)</td>
<td>410</td>
<td>350</td>
</tr>
<tr>
<td>Net Heat Rate (BTU/kWh)</td>
<td>10,020</td>
<td>11,045</td>
</tr>
<tr>
<td>Total Plant Cost ($/kW)</td>
<td>1,398</td>
<td>1,380</td>
</tr>
<tr>
<td>Fixed O&amp;M Cost ($/kW-yr)</td>
<td>43</td>
<td>40</td>
</tr>
<tr>
<td>Consumables (Mills/kWh)$^1$</td>
<td>0.5</td>
<td>4.8</td>
</tr>
<tr>
<td>Coal (Mills/kWh)</td>
<td>17.5</td>
<td>19.3</td>
</tr>
<tr>
<td>Levelized COE (Mills/kWh)$^2$</td>
<td>58.7</td>
<td>66.6</td>
</tr>
</tbody>
</table>

$^1$Include by-product credit
$^2$At 51% capacity factor

- Natural gas fueled

Combined Cycle (CC)
Gas Fired Steam

Plant operating performance, resource requirements, air emission characteristics, waste products, capital and operating and maintenance costs, and construction time for the various technologies are listed in Table 1.

A listing of gasification combined cycle projects in the United States is given in Table 2.

Coal-Fueled Technologies

Pulverized Coal--A conventional PC steam generating unit receives raw coal that has been pulverized and dried. The pulverized coal is burned in suspension in a waterwall boiler. Waterwalls in the boiler collect radiated heat and convert water to steam. Convective tube banks downstream of the boiler superheat the steam, which then powers the steam turbine generator.

Atmospheric Fluidized Bed Combustion--In an AFBC plant, the coal and limestone are fed into highly a turbulent fluidized bed combustor where combustion air, feed fuel, limestone sorbent, and recirculating solids are mixed. The velocities are high enough to remove the bed material from the combustor. The reacting gas and solids flow upward and enter a particulate separator, usually a cyclone, where solids are separated and returned to the bottom of the combustor. Flue gas leaves the cyclone and is cooled by a conventional convection pass and air heater.

Gasification Combined Cycle--A GCC plant gasifies coal, producing syngas fuel for a combined cycle powerplant. A GCC plant typically consists of one or more gasifiers, an Air Separation Unit (ASU), particulate and acid gas removal systems, sulfur recovery system, and a combined cycle power block.

The clean syngas is sent to the combustion turbines to generate power.

In an integrated GCC plant, high-pressure steam can be produced in the gasification island and mixed with the steam generated in the Heat Recovery Steam Generator (HRSG), increasing the power from the steam turbine. There may also be integration between the combustion turbines and the ASU. In that situation, a portion of the compressed air required by the ASU is extracted from the compressor section of the combustion turbines.

Pressurized Fluidized Bed Combustion--PFBC is a variation of fluidized bed technology which involves burning crushed coal and a sorbent in a pressure vessel at 10 to 15 atmospheres with combustion air delivered by a gas turbine compressor. Before the flue gas leaves the pressure vessel, the majority of entrained particles are removed by a series of cyclones. The hot flue gas then enters the gas turbine at essentially the temperature of the PFBC combustor and is expanded.
TABLE 1
CURRENT COAL AND NATURAL GAS FUELED TECHNOLOGIES

<table>
<thead>
<tr>
<th>Item</th>
<th>Coal Fueled Technologies</th>
<th>Natural Gas Fueled Technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PC</td>
<td>AFBC</td>
</tr>
<tr>
<td>Performance</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Plant Output, MW</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>Net Plant Heat Rate, BTU/kWh (HHV)</td>
<td>10,090</td>
<td>10,360</td>
</tr>
<tr>
<td>Resources Requirements</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Makeup Water, Mgpd</td>
<td>6.2</td>
<td>6.1</td>
</tr>
<tr>
<td>Coal, tpd</td>
<td>6,800</td>
<td>6,980</td>
</tr>
<tr>
<td>Natural Gas, Mcfd</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Lime/Limestone, tpd</td>
<td>65</td>
<td>390</td>
</tr>
<tr>
<td>Air Emissions, lb/MMBTU</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂</td>
<td>206</td>
<td>206</td>
</tr>
<tr>
<td>CO</td>
<td>0.11</td>
<td>0.19</td>
</tr>
<tr>
<td>SO₂</td>
<td>0.04</td>
<td>0.05</td>
</tr>
<tr>
<td>NOₓ</td>
<td>0.10-0.17</td>
<td>0.10-0.15</td>
</tr>
<tr>
<td>Particulates</td>
<td>0.02</td>
<td>0.02</td>
</tr>
<tr>
<td>Solid Waste Products</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ash/Slag, tpd</td>
<td>330</td>
<td>640</td>
</tr>
<tr>
<td>Scrubber Solids, tpd</td>
<td>146</td>
<td>-</td>
</tr>
<tr>
<td>Sulfur Recovery, tpd</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Plant Operating Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fixed, $/kW-yr</td>
<td>18.85</td>
<td>16.40</td>
</tr>
<tr>
<td>Variable, $/MWh</td>
<td>4.10</td>
<td>4.10</td>
</tr>
<tr>
<td>Plant Capital Cost, $/kW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Direct Cost</td>
<td>1,100</td>
<td>1,200</td>
</tr>
<tr>
<td>Indirect Cost</td>
<td>140</td>
<td>155</td>
</tr>
<tr>
<td>Total Capital Costs</td>
<td>1,240</td>
<td>1,355</td>
</tr>
<tr>
<td>Plant Construction Schedule, months</td>
<td>34</td>
<td>30</td>
</tr>
</tbody>
</table>

in the turbine which drives the compressor and a generator. Heat is recovered from the gas turbine exhaust by an economizer. Steam generated in the PFBC boiler is used by the steam turbine which generates 80 percent of the plant electrical output.

Natural Gas-Fueled Technologies

Combined Cycle--The CC technology captures exhaust heat from the gas combustion turbines that would otherwise be wasted in simple cycle operation. The exhaust heat from the combustion turbines is used to generate steam which is then directed to a steam turbine to generate additional power.

Gas-Fired Steam--Gas-fired steam units have a conventional waterwall furnace, with burners mounted on the furnace walls to mix the fuel with air before combustion within the furnace. Waterwalls in the furnace collect radiated heat and convert water to steam. Con-

SYNTHETIC FUELS REPORT, MARCH 1994
### TABLE 2

**U.S. GASIFICATION COMBINED CYCLE PROJECTS**

<table>
<thead>
<tr>
<th>Owner</th>
<th>Plant</th>
<th>Fuel</th>
<th>Capacity (MW)</th>
<th>Gasification Technology</th>
<th>Project Status</th>
<th>Oper. Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Texaco</td>
<td>Cool Water</td>
<td>Coal</td>
<td>120</td>
<td>Texaco</td>
<td>Being Retired</td>
<td>1986</td>
</tr>
<tr>
<td>Shell Oil Co.</td>
<td>SCGP-1</td>
<td>Coal</td>
<td>-</td>
<td>Shell</td>
<td>Retired</td>
<td>1987</td>
</tr>
<tr>
<td>Dow Chemical</td>
<td>LGTI</td>
<td>Coal</td>
<td>160</td>
<td>Destec</td>
<td>Operating</td>
<td>1987</td>
</tr>
<tr>
<td>City of Springfield,</td>
<td>Energy</td>
<td>Coal</td>
<td>65</td>
<td>ABB/CE</td>
<td>Planned</td>
<td></td>
</tr>
<tr>
<td>Illinois</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tampa Electric</td>
<td>Polk County IGCC</td>
<td>Coal</td>
<td>263</td>
<td>Texaco</td>
<td>Planned</td>
<td>1996</td>
</tr>
<tr>
<td>General Electric/Texaco</td>
<td>Puerto Rico</td>
<td>Coal</td>
<td>260</td>
<td>Texaco</td>
<td>Planned</td>
<td>1997</td>
</tr>
<tr>
<td>TVA</td>
<td>Wabash</td>
<td>Coal</td>
<td>255</td>
<td>Destec</td>
<td>Planned</td>
<td>1995</td>
</tr>
<tr>
<td>TVA</td>
<td>IGCC/F Plant</td>
<td>Coal</td>
<td>260</td>
<td>Shell</td>
<td>Planned</td>
<td>1999</td>
</tr>
<tr>
<td>Tamco Power Partners</td>
<td>Towner IGCC</td>
<td>Coal</td>
<td>60</td>
<td>Lurgi</td>
<td>Planned</td>
<td></td>
</tr>
<tr>
<td>Sierra Pacific Power</td>
<td>PINON PINÉ</td>
<td>Coal</td>
<td>80</td>
<td>Wheeler/KWR</td>
<td>Planned</td>
<td>1997</td>
</tr>
<tr>
<td>Coastal</td>
<td>Towner IGCC</td>
<td>Coal</td>
<td>60</td>
<td></td>
<td>Planned</td>
<td></td>
</tr>
</tbody>
</table>

**Figure 1**

**AIR EMISSIONS COMPARISON**

*Source: Kalin, et al.*

Vective tube banks superheat the steam, which then powers the steam turbine generator.

**Environmental Acceptability**

Increasing environmental restrictions have made emissions (particulate and gaseous) one of the most critical issues with regard to future generation resources. Emission levels on a pound per million BTU basis are shown in Table 1. A graphical comparison of air emissions (pounds per megawatt-hour) is provided in Figure 1.

With the exception of carbon emissions, relatively low emission levels are achievable for all of the generation technologies.

The natural gas-fueled technologies offer the lowest emission profiles, according to the authors.

The coal-fueled technologies require far greater levels of water consumption and substantial provisions for waste disposal. The waste disposal requirements are primarily associated with emission controls. Current waste disposal methods, basically landfilling and use of waste as salable byproducts, demonstrate the ability to dispose of solid wastes. The use of water in power generation facilities is an important consideration, particularly in those states where water availability is at critical levels.
Economic Comparison

The economic comparisons of Kalin, et al., are based on projections of levelized electric rates for each technology. Levelized electric rates are calculated over a 30-year period, beginning in 2000, using a utility rate base model. The model includes all capital, fuel, non-fuel fixed and variable operation and maintenance costs and appropriate emissions costs. The capital costs, operation and maintenance costs, and unit performance characteristics are listed in Table 1.

In all evaluations, the 1993 delivered price of coal is assumed to be $1.30 per million BTU. Natural gas is assumed to be $2.50 per million BTU.

A levelized cost comparison was completed for the five technologies and is shown in Figure 2. The comparative electric rates, which are levelized over the 30-year period beginning in 2000, are based on a 4 percent escalation in coal and natural gas prices. Levelized electric rates, which are in nominal dollars beginning in 2000, are plotted as a function of capacity factor.

Given the fuel price assumptions which are based on natural gas and coal escalating at 4 percent, the CC is clearly the low cost option because of its low capital cost and better operating efficiency. Natural gas steam also compares favorably to the coal-fueled technologies.

The cost impact associated with a decreasing capacity factor is significant. With the exception of the CC, electric rates increase substantially as the capacity factor goes from 80 to 50 percent.

The cost impact associated with changing capacity factor illustrates another point regarding capital cost. Technologies that are higher in capital cost not only expose the utility to regulatory risk associated with prudence review disallowances, but also to financial risk attributed to changing operating conditions. At this time, GCC represents a greater financial risk because of its relatively higher capital cost.

Cost of Environmental Acceptability

The cost of environmental acceptability has two components. The first component deals with actual control of emissions. This can be measured by the initial cost of installing the equipment necessary to reduce emissions and the subsequent operating cost increase incurred over the life of the plant. The second component is based on the cost associated with plant emissions as defined by the market value of emissions, environmental externality cost, potential taxes on carbon emissions, etc.

An analysis of marginal capital and operating costs associated with various control technologies indicates a 14 percent increase in levelized electric rates is attributed to control of NOₓ and SOₓ emissions on the PC unit over the evaluation period. The increase is based on a comparison between levelized electric rates for non-controlled and controlled emissions. The significant capital cost of a lime spray dryer, SCR, and the raw material necessary to operate the systems caused the increase.

As a result of using the combustion process to reduce emissions, the AFBC unit requires fewer capital intensive controls. AFBC control costs, which are primarily related to the capital cost of the SNCR system and limestone material handling system, are approximately 5 percent higher than the base cost, assuming no controls. As expected, the use of a cleaner fuel such as natural gas results in a lower marginal cost of environmental controls on the CC unit.

Control of emissions is inherent in the design of the GCC plant, therefore, a marginal cost was not determined for this technology. The marginal cost of NOₓ control for the natural gas steam unit was considered to be a small part of the cost of combustion burner design, so this technology also was not considered.
GCC Economics

GCC has received increased attention as a promising generation technology for the late 1990s. However, the economics of the technology and limited application beyond the demonstration phase have prevented its use on a wide-scale commercial basis.

The breakeven direct capital cost for an integrated GCC unit versus a CC unit is shown in Figure 3. Breakeven direct capital cost is plotted as a function of the levelized fuel price differential between natural gas and coal. The graph is based on the breakeven levelized electric rate for the two technologies.

The figure illustrates the reduction in GCC direct capital cost required based on a range of natural gas/coal levelized fuel price differentials. The required direct capital cost levels are compared to a current direct capital cost of $1,350 per kilowatt for the GCC. Further reductions in GCC capital cost are possible given that the technology is still relatively new and improvements in combustion turbine technology and gas cleanup systems are planned. It is important to note that the reductions in GCC capital cost shown are mainly attributed to decreases in the gasification system costs and further improvements in plant integration designs, according to the authors. Any decrease in the combined cycle portion of the GCC plant would also apply to the stand-alone CC option and would therefore be offset in the breakeven comparison.
HISTORY OF DISPERSED CATALYSTS IN COAL LIQUEFACTION REVIEWED

Dispersed catalysts generally have little internal porosity and the active sites are on the exterior surfaces of the particles. These catalysts are more effective than supported catalysts for promoting the initial conversion of coal to soluble form. The high dispersion of the catalyst makes recovery difficult if not impossible, and therefore the cost of the catalyst is a critical factor. Numerous metals have been tested for possible use as dispersed catalysts, including molybdenum, tungsten, iron, cobalt, nickel, ruthenium, vanadium, germanium, tin, zinc, and mixtures of these metals. The activity of dispersed catalysts depends on a number of factors, including the phase of the precursor, the mode of its addition, and the extent of contact with the coal. Interactions with other components, either native to the coal or added, can also significantly affect the activity of the catalyst. The rank of the coal feed also influences the performance of the catalyst.

The history of the use of dispersed catalysts in coal liquefaction was reviewed by G.T. Hager and F.J. Derbyshire, of the Kentucky Center for Applied Energy Research. The review was presented in a paper at the 10th Annual International Pittsburgh Coal Conference, held in Pittsburgh, Pennsylvania in September.

Before 1945

The first recorded application of catalysts to coal liquefaction was the use of hydroiodic acid by Berthelot in 1869. The thermal hydrogenation process developed by Bergius in 1911 was soon improved by the addition of Luxmasse, a byproduct of aluminum production that contained appreciable concentrations of iron and other metals, to remove sulfur.

By the mid-1920s, German researchers had developed a two-stage coal liquefaction process. The first stage, liquid phase hydrogenation, involved the conversion of coal to a middle distillate oil boiling below 325°C. The middle oil was then upgraded to lighter distillate products by a vapor phase hydrogenation over a fixed bed of supported catalyst. The first stage required the use of a highly dispersed catalyst due to the rapid deactivation caused by coking.

Because of the war effort in Germany in the 1930s and 1940s both direct and indirect liquefaction of native coals were carried out on a large scale. Direct coal liquefaction was used to supply over 90 percent of the aviation-grade fuel used by the Luftwaffe.

One of the first catalysts investigated for the liquefaction of a brown coal and brown coal tar was finely ground molybdenum at concentrations up to 25 percent. Due to the limited availability and cost of molybdenum catalysts, they were soon replaced by low-cost iron ores. Bayermasse, a byproduct from the production of aluminum, was found to be an especially good catalyst for the hydrogenation of brown coal at loadings of 2 percent or more.

While iron catalysts provided some catalytic effect for the processing of bituminous coals, it was found that the use of a tin catalyst was more effective. The addition of 0.06 percent tin oxalate and 0.4 to 1.0 percent NH₄Cl gave higher conversion and better selectivity to oils than 3 percent iron oxide. However, the HCl produced in the process resulted in problems with corrosion. The performance of the iron oxide catalysts was improved by replacing some of the Bayermasse with impregnated ferrous sulfate.

1945-1980

After the end of World War II, the United States investigated much of the German technology in a 200 to 300-barrel per day plant constructed in Louisiana, Missouri. Coal derived liquids could only be produced at high cost. Incentives for further research in the United States were limited up to the 1970s, primarily due to the availability of vast reserves of inexpensive oil from the Middle East. The 1973 oil embargo created a resurgence of interest in coal liquefaction. Four distinct processes evolved from these efforts—the H-Coal process, the Exxon Donor Solvent process, and two Solvent Refined Coal processes. All were single-stage processes. By the late 1970s and early 1980s these processes were being developed at the pilot plant scale.

The Dow coal liquefaction process, also developed during this period, used a highly dispersed molybdenum catalyst for the liquefaction of both bituminous and subbituminous coals in a single-stage operation.
Several techniques have been utilized to produce nanometer size particles for introduction into the feed slurry. A laser pyrolysis technique has been used to produce a variety of iron-based particles, including two phases of iron carbide (Fe₃C and Fe₇C), two phases of iron nitride (Fe₄N and Fe₄N), plus an iron sulfide (Fe₅S), an alpha-iron. These particles show moderate catalytic activity for the conversion of a sub-bituminous coal.

The flame pyrolysis of metal chloride vapors has been used to produce nanometer-sized aerosol oxides. Iron oxide particles generated by this technique have demonstrated a high catalytic activity for the liquefaction of a bituminous coal, resulting in conversions only slightly lower than obtained with a similarly produced molybdenum oxide.

Another method to increase the dispersion of the catalyst is direct impregnation on the coal of an iron catalyst precursor, as originally utilized in Germany. The addition of iron to low-rank coals by ion exchange has also shown promising results.

Another route to improving the activity of iron catalysts is to modify their composition. One approach has been to change the surface properties of hematite particles either by treating a precipitated FeOOH with H₂SO₄ or by precipitating FeOOH in the presence of the sulfate anion. Studies of these particles after calcining indicate the formation of Fe₂O₃/SO₄²⁻. This notation denotes SO₃ chemisorbed on the surface of Fe₂O₃ in a nonstoichiometric relationship. Liquefaction studies showed a significant increase in the total conversion at a loading of 3,500 ppm of Fe.

The addition of small amounts of promoter metals, such as molybdenum and titanium, has been shown to improve the effectiveness of the iron-based catalysts.

In the late 1970s, the advantages of two-stage processing were rediscovered, although in somewhat different form than first developed in Germany. It was seen that the dissolution and upgrading steps required different reaction regimes, and that they should be carried out in separate reactors using different catalysts. The addition of 2 percent iron oxide with dimethyl disulfide to the first-stage feed slurry was found to significantly improve the conversion of bituminous coals in the integrated two-stage liquefaction process. Furthermore, the processing of sub-bituminous coals was shown to be impossible without the addition of an iron catalyst in the first stage.
finished candle is monolithic, virtually free of internal stresses or flaws. A sintered SiC candle is available but is much more expensive than clay bonded.

### HOT-GAS PARTICULATE REMOVAL SYSTEMS STUDIED FOR IGCC APPLICATIONS

Integrated Coal Gasification Combined Cycle (IGCC) systems which have been designed with cold-gas cleanup processes, have rarely raised concerns of particulate control, because of the cleansing effect of the cold cleanup. However, with the advent of hot-gas contaminant control systems to improve efficiencies, the presence of particulates has influenced the design of IGCC plants and processes. The primary purpose of particulate collection devices is to protect the turbine from the erosive action of flyash. Particulates can also increase pressure drop in fixed-bed reactors, e.g., desulfurization absorbers, chloride guards, etc.

The types of particulate removal devices available and under development were studied by Gilbert/Commonwealth, Inc., of Reading, Pennsylvania. The results of this study were discussed in a paper by R. Zaharchuk and M.D. Rutkowski presented at the 10th Annual International Pittsburgh Coal Conference, held in Pittsburgh, Pennsylvania in September.

The gas produced in gasifiers contains reactive components such as CO and H₂. The coal gas also contains, in addition to char and ash particulates, hydrogen sulfide and carbonyl sulfide, alkalis and hydrogen chloride. Some of these components can cause deposition in heat exchangers or downstream turbines, corrosion and erosion severely impacting costs of operation and maintenance.

**Candle Filter**

The candle filter is a high-temperature, high-pressure particulate filtration device. Although the filter size can be varied, it has been optimized at 1.5 meters in length with a 60-millimeter outside diameter and a 30-millimeter inside diameter. One end is plugged and the other is flanged for mounting on a tube sheet. Composition is either clay bonded silicon carbide or aluminum oxide, and both are fired such that the

# Granular Bed Filter

Granular bed filters have been in use for many years collecting particulates at high temperatures. Both Combustion Power Company and Westinghouse are developing granular moving bed filters for possible testing at the Wilsonville gasifier test facility now being designed. There is interest in this type of filter because of past success at high temperature and pressure, and the many choices of filter media.

**Ceramic Fabric Filters**

Ceramic fabric-bag filters for high temperature, high pressure service have been under development for over 10 years.

Nextel 312, manufactured by 3M, is the fabric most likely to be used. It is a woven, seamless bag made of 8 micron alumina-boria-silica fibers. Typical bag size is 6 inches in diameter by 8 feet long. Maximum temperature rating is 2,100°F. The effective filtration area per bag is 12.5 square feet.

A nine-bag filter was tested successfully for over 16,000 hours at the University of North Dakota at atmospheric pressure and 800 to 1,000°F.

Typically the filters are suspended from a tube sheet. The flanged end can be recessed in the tube sheet which can be solid or water cooled. Dirty gas enters the pressure vessel, impinges on the outside of the filter and exits up through the center of the filter above the tube sheet. At a selected pressure drop a high pressure pulse of inert gas is used to blow off the cake similar to a pulse jet bag filter. Face velocities have varied from 2 to 20 feet per minute depending on filter cake characteristics.

The largest unit built so far has been for test work at the American Electric Power Tidd Pressurized Fluidized-Bed Combustion (PFBC) facility in Brilliant, Ohio. The filter vessel contains 384 1.5-meter candle elements in a 10-foot diameter by 40-foot tall vessel.

**Ceramic Fiber Candle Filter**

Ceramic fiber candle filters are made by amalgamating 2 to 3 micron fibers with each other using inorganic
binders. This produces a lightweight, self supporting filter that can operate up to 1,500°F.

BWF and Foseco are developing alumina silicate filters with various dimensions and testing them at temperatures to 1,472°F. Universal Poreotics, in addition to testing fiber candle filters, has designed tube sheets that are light weight and do not require cooling. The durability of these filters must be demonstrated.

Asahi Ceramic Tube Filter

The Asahi tube filter is made of porous beta-cordierite ceramic having a porosity of about 40 percent.

The dirty gas enters the top of the vessel and proceeds at high velocity downward through the inside of the filter tubes. Clean gas exists horizontally into three compartments and then outside of the vessel through side outlets. The filters are cleaned by a reverse pulse blowback which enters the clean gas exit pipe.

A number of tests were performed with success at industrial and coal firing sites; however, only 500 hours of testing has been done under gasifier conditions. Recent tests under PFBC conditions resulted in excessive tube failures.

Ceramic Cross-Flow Filter

The cross-flow filter element is a 12x12x4-inch gas permeable membrane layered and oriented at 90° angles so that dirty gas enters, passes through the membrane and then exits perpendicularly to a sealed end of the filter. Multiple elements are attached to a plenum through which clean gas exits. The plenums are hung from a tube sheet which can be water cooled. Cleaning is done periodically by a pulse jet using induced air venturis.

Field tests have been done at seven sites, one of them under coal gasification conditions. While all tests were considered successful, delamination is still a problem.

A ceramic filter has been developed by CeraMem Corporation that is similar to the cross flow filter. The CeraMem ceramic monolith filter is a porous cordierite honeycomb monolith containing a large number of parallel passageways. Alternate ends are plugged so that dirty gas flows into inlet open passageways, passes through membrane coated walls and then exits at the opposite end. Inlet/outlet openings are much smaller than the cross flow filter, resulting in a high filtration area per unit volume.

A key difference from the cross flow filter is a membrane coating. The coating (50 microns) allows high filtration efficiency at low resistance.

Conclusions

Based on the test results and future planned facility designs Zaharchuk and Rutkowski concluded that the candle filter is the only device that can be recommended at this time for gasifier hot gas cleanup. Rapid advances are being made in ceramic element design and improvement, however, and these development designs must be considered.

Candle filter cost versus the cost of other filters are compared in Table 1. The table shows that there is a significant reduction in cost for the filters with high surface areas. The table compares element prices for a nominal 1,000 cubic feet per minute filter and shows the volume needed for the pressure vessel.

Other conclusions include the following:

- The long-term durability of the SiC candle filter is still a technical issue; however, below 1,200°F it can be recommended for gasifier cleanup.

- Particulates from gasifiers are not well characterized. As a result it is difficult to predict performance using available filtration models. Particulates from various gasifiers should be analyzed.

- Barrier filters with high surface to volume ratios can offer substantial savings in capital costs and their development should be encouraged.

- Thermal/chemical effects on ceramics should be determined under gasifier conditions. Backflush techniques also need development and study.

- The efficiency of ceramic barrier filters is high, easily meeting gas turbine and New Source Performance Standards requirements, but failure detection devices are mandatory.
### TABLE 1

**COST OF ELEMENTS FOR FILTERING 1,000 ACTUAL CUBIC FEET PER MINUTE AT 2.5 FEET PER MINUTE**

<table>
<thead>
<tr>
<th>Filter</th>
<th>Cost per Element</th>
<th>Elements Required</th>
<th>Cost for 1,000 ACFM</th>
<th>Volume for 1,000 ACFM, ft³</th>
</tr>
</thead>
<tbody>
<tr>
<td>CeraMem</td>
<td>$1,961</td>
<td>11</td>
<td>$21,571</td>
<td>2.6</td>
</tr>
<tr>
<td>Cross Flow</td>
<td>1,200</td>
<td>33</td>
<td>39,600</td>
<td>9.9</td>
</tr>
<tr>
<td>Candle</td>
<td>504</td>
<td>143</td>
<td>72,072</td>
<td>22.2</td>
</tr>
<tr>
<td>Ceramic Bag</td>
<td>500*</td>
<td>32</td>
<td>16,000</td>
<td>50.0</td>
</tr>
</tbody>
</table>

*Does not include cost of bag support tube.

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LIQUID PHASE METHANOL ATTRACTIVE FOR DISPATCHABLE ENERGY STORAGE

Gasification Combined-Cycle (GCC) power generation is fundamentally a baseload technology. However, GCC can also be economically developed for load-following by incorporating energy storage in the flow-sheet. The Liquid Phase Methanol (LPMEOH) process has been developed for this application. Methanol is produced from coal-derived synthesis gas off-peak, and withdrawn from storage and fired on-peak. In a paper study LPMEOH technology has been applied to convert a 500-megawatt GCC baseload reference plant into a flexible, load-following unit with a peak/valley capacity ratio of 3:1. The economics and comparative emissions performance of this dispatchable GCC energy storage plant were discussed in a paper by F.S. Frenduto, et al., of Air Products and Chemicals, Inc. which was presented at the Joint ASME/IEEE Power Generation Conference, held in Kansas City, Kansas in October.

**LPMEOH Process**

LPMEOH technology is tailored to the direct processing of the CO-rich gas characteristics of gasification. Instead of a vapor phase reaction, methanol synthesis occurs in a liquid phase or slurry medium. The methanol catalyst exists in powder form and is slurried in an inert mineral oil. The syngas is bubbled up through the slurry, and the reaction occurs via dissolved gases in the liquid. The methanol produced at the catalyst surface diffuses out of the liquid and exits the reactor in the vapor state. It is then recovered as liquid product by cooling and condensation.

Liquid phase reaction technology embodies characteristics that are quite different from conventional vapor phase methanol synthesis:

- The reaction exotherm is neutralized by the liquid heat sink. As a result, concentrated reactants and high conversions are tolerable. There is no need for a large recycle ratio. The low pressure reactor is a true isothermal reactor.

- CO-rich gas is accommodated directly. There is no need to shift the gas and remove CO₂. There is no need to dilute the CO concentration.

- The reactor can start, stop, idle, and ramp rapidly. There is no need to carefully control gas composition and flowrate to protect the catalyst. The reactor is robust and suitable for load-following.

- Catalyst life is good with high CO concentrations.
Catalyst change-out can be accomplished without shutdown. Catalyst addition and withdrawal is practiced on a small, intermittent-flow basis.

Reference GCC Plant

The selected reference GCC plant design is based on two General Electric Frame 7FA combustion turbines operating in a combined-cycle configuration. Eastern bituminous, run-of-mine coal is gasified in two high temperature, entrained-flow gasifiers to produce 3,400 million BTU per hour (lower heating value) of clean fuel gas. Moisture addition is employed to control NOx to less than 25 ppmv (dry, 15 percent O2) and to fully load the combustion turbines to their 192 megawatt rated capacity. Two 105-megawatt steam turbines utilize the exhaust heat to yield a gross power island output of 594 megawatts. After auxiliary loads are accommodated, the plant produces a net output of 527 megawatts.

The calculated heat rate for this plant is 8,270 BTU per kilowatt-hour on a high heating value basis. With this attractive efficiency on coal, this plant would normally be a baseload unit with a high dispatch priority.

The reference plant is assumed to operate at an 85 percent annual availability. Outages are assumed to be proportionately spread over both the on-peak and off-peak periods.

The reference plant cost is estimated at $738 million, or $1,400 per kilowatt.

Dispatchable Energy Storage (DES) Plant

For the DES plant, an LPMEOH unit is added to the reference plant flowsheet to provide the capability for energy storage during periods of low power demand. In order to provide maximum on-peak capacity, a third 7FA combustion turbine is also added (see Figure 1).

![Diagram of Dispatchable Energy Storage (DES) Plant](image-url)
The third combustion turbine is configured to burn methanol from storage.

Each of the three combustion turbines supplies heat to a common bottoming steam section powering two steam turbines.

The gasification island is identical to that of the reference plant. However, a 1,470-ton per day LPMEOH unit is inserted between the gas cleanup section and the fuel saturators with appropriate controls to allow between 0 percent and 100 percent of the synthesis gas to pass through the methanol synthesis unit. During periods of low power demand, the gasifiers are operated at 90 percent of capacity and all of the synthesis gas is passed through the LPMEOH unit. The off-peak power output is 247 megawatts.

During periods of high power demand, the methanol unit is by-passed, the gasifiers run at full capacity and two of the combustion turbines are fired on syngas. The third turbine burns methanol from storage. Net power output increases to 778 megawatts. Thus, the DES plant offers a 3.1:1 ratio of on-peak/off-peak capacity.

Comparative Economics

The relative economic attractiveness of the proposed DES plant versus a conventional baseload GCC design hinges primarily on two factors:

- Incremental capital and operating costs required to provide the load-following flexibility
- Relative value of power produced during intermediate- and peak-demand periods versus off-peak power

The performance parameters for the two study cases are summarized in Table 1. These data show that the DES plant produces less than one-half of the amount of annual off-peak energy (when most utilities do not require capacity) as the reference plant, and 1.55 times more on-peak energy as the reference plant.

Estimates of the average annual heat rates for the two cases are also included in Table 1. Conversion losses inherent in the energy storage case result in a 750-BTU per kilowatt-hour average heat rate penalty for this case. Even with this penalty however, the power produced by the DES plant is, on average, highly efficient as compared with conventional schemes to meet the same load pattern.

Comparative capital and operating costs for the two cases are shown in Table 2. The DES plant requires about 30 percent higher capital investment.

Of course, this incremental capital cost could be sharply reduced if existing combustion turbines within a utility system were modified to accommodate

<table>
<thead>
<tr>
<th>Baseload Reference Plant</th>
<th>Dispatchable Energy Storage Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Capacity, MW</td>
<td></td>
</tr>
<tr>
<td>On-Peak Period</td>
<td>527</td>
</tr>
<tr>
<td>Off-Peak Period</td>
<td>527</td>
</tr>
<tr>
<td>Annual Generation, GWH</td>
<td></td>
</tr>
<tr>
<td>On-Peak Period</td>
<td>1,402</td>
</tr>
<tr>
<td>Off-Peak Period</td>
<td>2,523</td>
</tr>
<tr>
<td>Average Heat Rate, BTU/kWh (HHV)</td>
<td>3,925</td>
</tr>
<tr>
<td></td>
<td>8,270</td>
</tr>
</tbody>
</table>
TABLE 2
COST COMPARISON OF ENERGY STORAGE VS. BASELOAD CASES

<table>
<thead>
<tr>
<th></th>
<th>Baseload Reference Plant</th>
<th>Dispatchable Energy Storage Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed Capital Cost, 1993$</td>
<td>$738.0 MM</td>
<td>$959.0 MM</td>
</tr>
<tr>
<td>Annual Capital Charge per TAG</td>
<td>78.2</td>
<td>101.6</td>
</tr>
<tr>
<td>Annual Operating Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel @ $1.50/MMBTU</td>
<td>48.7</td>
<td>45.5</td>
</tr>
<tr>
<td>Fixed Operating</td>
<td>20.4</td>
<td>24.6</td>
</tr>
<tr>
<td>Non-Fuel Variable Operating</td>
<td>16.1</td>
<td>15.3</td>
</tr>
<tr>
<td>Total Operating</td>
<td>85.2</td>
<td>85.4</td>
</tr>
<tr>
<td>Total Annual Cost</td>
<td>$163.4 MM</td>
<td>$187.0 MM</td>
</tr>
</tbody>
</table>

methanol fuel (at modest costs) and deployed as the peaking capacity in place of the third new 7FA.

Fuel costs for the reference plant case are actually higher than for the DES case because of the turn-down of the gasifiers during off-peak hours in the DES case.

Intangible benefits of the DES concept not reflected in the economic analysis are as follows:

- Greater system flexibility
- Expanded peaking capacity
- Greater system reliability
- Improved long-term fuel cost security
- Low emissions

Comparative Emissions

The proposed DES plant offers an attractive emissions profile compared to conventional technology, according to the authors.

The emissions of the DES facility have been compared to an alternative baseload Pulverized Coal/Flue Gas Desulfurization (PC/FGD) plant with a distillate-fired combined-cycle unit (Table 3, next page). The comparison in Table 3 is made with both facilities producing the same annual megawatt-hours of off-peak and on-peak power.

As shown in the comparison, the GCC/LPMEOH facility produces low annual emissions of SO$_2$ and NO$_x$. The emissions of SO$_2$ and NO$_x$ are one-sixth and one-eighth of their respective counterparts produced by the PC/FGD alternative. Frenduto et al., conclude that even with other alternatives such as advanced PC/FGD (95 percent sulfur removal and deeper NO$_x$ control) or PC/FGD combined with pumped hydro for peaking power, the GCC-based Dispatchable Energy Storage plant will still enjoy a significant environmental advantage.

LIGNITE OVERBURDEN FROM CLAY MINING COULD BE RETORTED

Lignite is removed as overburden in the mining of ball clay from the Eocene of Kentucky's Jackson Purchase region, but is not currently mined as an energy resource but rather is a waste product. About 160,000 tons of clay was mined in 1991, with an estimated 40,000 tons of lignite moved in the process. The high moisture, low heating value lignite has not been competitive as an energy resource due to its proximity to the higher quality bituminous coals in the nearby Illinois Basin and, more recently, to the import of Powder River Basin coals into the lower Ohio River Valley. Potential uses of the lignite which could provide the opportunity to develop it as an added resource along with the clay were examined by the Kentucky Center for Applied Energy Research. Results were reported by J.C. Hower, et al., in a paper
presented at the 206th American Chemical Society National Meeting, held in Chicago, Illinois in August.

The lignite sample was obtained from the Eocene Claiborne Formation, Milburn 7.5-minute quadrangle, Carlisle County, Kentucky.

The sample was retorted in nitrogen-swept fixed-bed experiments. The objective of this part of the research was to obtain the oil yields of the lignite sample. Results of the retorting experiments indicate that 11.7 weight percent oil may be obtained during pyrolysis.

The oils derived from the lignite are waxy. Large amounts of water were also captured during the retorting of the lignite sample. Because most of the water was released before the sample was heated to above 150°C, it may be concluded that only small amounts of structural water were released by clay minerals which occur as ash components within the lignite sample.

The processed lignite sample was analyzed for carbon, hydrogen, nitrogen, and sulfur by using automated LECO elemental analyzers. Ultimate and proximate analyses of the retorted lignite sample are illustrated in Table 1. Most of the moisture was released during pyrolysis. After pyrolysis, the retorted lignite sample was found to have high fixed-carbon values (Table 1).

Microscopic examination revealed that the retorted lignite had formed an intricate network consisting of variously sized pores and charred carbonaceous material, according to the authors. Heating Stage Microscope (HSM) observations helped to establish the spatial relationships between process induced pores and char. In addition, the HSM experiments allowed the precise determination of the boiling temperature at which constituents in the macerals start to vaporize. The development of a porous structure in a carbon-rich pyrolysis residue of the lignite may indicate the lignite's potential as source material for the production of adsorbent carbons.
TABLE 1
ULTIMATE AND PROXIMATE ANALYSES OF
RAW AND PYROLYZED LIGNITE SAMPLE

<table>
<thead>
<tr>
<th></th>
<th>Raw Sample</th>
<th>Pyrolyzed Sample</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>As Rec.</td>
<td>Dry</td>
</tr>
<tr>
<td>Moisture</td>
<td>10.97</td>
<td></td>
</tr>
<tr>
<td>Ash</td>
<td>19.11</td>
<td>21.16</td>
</tr>
<tr>
<td>Volatile Matter</td>
<td>51.30</td>
<td>57.62</td>
</tr>
<tr>
<td>Fixed Carbon</td>
<td>18.60</td>
<td>20.89</td>
</tr>
<tr>
<td>Carbon</td>
<td>50.00</td>
<td>56.16</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>6.03</td>
<td>5.39</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.96</td>
<td>1.08</td>
</tr>
<tr>
<td>Oxygen</td>
<td>11.85</td>
<td>14.70</td>
</tr>
<tr>
<td>Sulfur</td>
<td>1.08</td>
<td>1.21</td>
</tr>
<tr>
<td>Heating Value (BTU/lb)</td>
<td>8,690</td>
<td></td>
</tr>
<tr>
<td>Heating Value (MJ/kg)</td>
<td>20.26</td>
<td></td>
</tr>
</tbody>
</table>

###

AIR-BLOWN VERSUS OXYGEN-BLOWN PRENFLO GASIFIERS COMPARED

A study is being conducted that compares air-blown and oxygen-blown coal gasification in a combined cycle powerplant based on the PRENFLO gasifier. Work to date was discussed in a paper by U. Buskies, et al., which was presented at the 12th Electric Power Research Institute Conference on Gasification Powerplants, held in San Francisco, California in October.

The following gasification conditions were selected:

- Air-blown (insulated gasifier)
  Oxidant temperature 550°C
  Gasification temperature: \( t_{250} + 25°C \)

- Oxygen-blown (cooled gasifier)
  Oxidant temperature: not applicable
  Gasification temperature: \( t_{250} + 150°C \)

The notation \( t_{250} \) refers to the coal ash viscosity temperature.

Plant Concepts

Both the air-blown and oxygen-blown gasification methods are based on the highly integrated Gasification Combined-Cycle (GCC), which integrates the combustion turbine compressor with the coal gasification oxidant supply. In this concept, the air required as oxidant for gasification is extracted from the combustion turbine. At this point, the discharge pressure of the combustion turbine compressor corresponds closely to the pressure required in the combustion chamber of the combustion turbine. The coal gasifier, though, must work at a higher pressure in order to overcome the downstream pressure losses of cooling, cleaning, and conditioning the coal gas. The air-blown method increases the pressure of the oxidant air using the high temperature booster compressor previously discussed. In the oxygen-blown method, the air extracted from the combustion turbine is first cooled and sent to an air separation unit from which the separation products--oxygen and nitrogen--are compressed for use in the gasifier and in the combustion chamber of the combustion turbine. The process sequence of the gas treatment facilities is identical for both air-
blown and oxygen-blown gasification methods. These gas treatment facilities are required for cleaning and conditioning the coal gas.

Figure 1 shows the air-blown GCC plant configuration. Figure 2 shows the oxygen-blown GCC plant configuration which is similar to the air-blown concept. The primary difference between the two concepts is that in the oxygen-blown method, the oxidant air is sent from the combustion turbine to an Air Separation Unit (ASU).

The coal gas volume for the air-blown method is about twice that of the oxygen-blown method, thus more auxiliary power is required.

**Performance**

The estimated plant performance for the two concepts is presented in Table 1 in terms of electric output, efficiency, and net plant heat rate for the summer design conditions. The net plant output of the air-blown GCC plant is 22.4 megawatts greater than the output of the oxygen-blown GCC plant.

**Combustion Turbine**—The difference in the V84.4 combustion turbine electrical output reflects the different mass flows extracted from the compressor portion of the combustion turbines. The nitrogen required for inertization and pneumatic transportation of coal dust in the air-blown concept is provided by a separate nitrogen unit. All air drawn into the combustion turbine compressor is used for power production. Therefore, the air-blown concept results in about 4 megawatts more of combustion turbine output than does the oxygen-blown concept.

**Steam Turbine**—The steam turbine of the air-blown concept produces greater output, because the greater quantity of coal gas rejects more sensible heat to the

**TABLE 1**

PERFORMANCE SUMMARY AT 32°C (90°F)

<table>
<thead>
<tr>
<th></th>
<th>Air-Blown</th>
<th>Oxygen-Blown</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Feed Rate, Dry</td>
<td>3,022</td>
<td>2,868</td>
</tr>
<tr>
<td>metric ton/day</td>
<td>3,332</td>
<td>3,162</td>
</tr>
<tr>
<td>Combusion Turbine Output, MW</td>
<td>296.4</td>
<td>292.4</td>
</tr>
<tr>
<td>Steam Turbine Output, MW</td>
<td>228.8</td>
<td>202.9</td>
</tr>
<tr>
<td>Gross Plant Output, MW</td>
<td>525.2</td>
<td>495.3</td>
</tr>
<tr>
<td>Auxiliary Power, MW</td>
<td>(45.5)</td>
<td>(38.0)</td>
</tr>
<tr>
<td>Net Plant Output, MW</td>
<td>479.7</td>
<td>457.3</td>
</tr>
<tr>
<td>Net Plant Heat Rate, HHV</td>
<td>8,090</td>
<td>8,050</td>
</tr>
<tr>
<td>kJ/kWh</td>
<td>7,670</td>
<td>7,630</td>
</tr>
<tr>
<td>Net Plant Efficiency, %</td>
<td></td>
<td></td>
</tr>
<tr>
<td>HHV</td>
<td>44.5</td>
<td>44.7</td>
</tr>
<tr>
<td>LHV</td>
<td>46.7</td>
<td>46.9</td>
</tr>
</tbody>
</table>
steam cycle, which is used for generating additional output. The air-blown concept results in about 25.9 megawatts more steam turbine output than does the oxygen-blown concept.

Auxiliary Power--The air-blown concept has a higher auxiliary power consumption than does the oxygen-blown concept. The hot air booster compressor requires almost the same amount of power as the air separation plant equipment in the oxygen-blown concept. The fuel plant equipment of the air-blown concept must be larger and designed to handle almost twice the amount of gas than the oxygen-blown concept and therefore requires much more auxiliary power. The power requirements of the power block auxiliary equipment and the general facilities are similar. The air-blown concept requires about 7.5 megawatts more auxiliary power than does the oxygen-blown concept.

Efficiencies--Table 1 presents the net plant heat rates and efficiencies of producing power from coal for the two GCC concepts. The performance results indicate that there is little efficiency difference between the air-blown and oxygen-blown concepts. Based on the Higher Heating Value (HHV) of the coal, the air-blown GCC concept is estimated to have a 44.5 percent efficiency, while the oxygen-blown GCC concept is estimated to have a 44.7 percent efficiency.

Conclusions

The authors conclude that air-blown coal gasification in GCC applications seems to be feasible if the oxidant air is supplied at as high a temperature as technically feasible and if the gasifier is insulated. The overall plant efficiency is then on the same high level as that of an oxygen-blown GCC concept. In general, the evaluation points out that the air-blown GCC concept may be feasible from a plant efficiency point of view for high quality coals. However, the oxygen-blown GCC concept seems to provide greater fuel flexibility, especially when considering lower rank fuels such as lignites, subbituminous coals and biomass.

AROMATIC POLYMERS PRECURSORS COULD PROVIDE A NEW DIRECTION FOR COAL CHEMICALS

As the coal industry moves into the 21st century, it will face increased regulatory and environmental pressures, as well as competition from other fuels--such as natural gas--that may erode some of coal's traditional markets. The continued health of the coal industry may depend, at least in part, on finding new, non-traditional markets for coal. According to a paper by C. Song and H. Schobert, of the Pennsylvania State University, an excellent opportunity exists for using coal as a feedstock for the production of specialty chemicals and advanced materials.

The paper was presented at the 10th Annual International Pittsburgh Coal Conference, held in Pittsburgh, Pennsylvania in September.

Song and Schobert focus on a few selected examples of specialty chemicals and advanced materials from coal, with particular concern for some new, high-value aromatics. The key point to be borne in mind is that the molecular architecture of most coals is based primarily on aromatic structures; for many bituminous coals, for example, about three of every four carbon atoms in the coal is aromatic. Thus with new approaches to converting the ill-defined macromolecular aromatic structure of coal to well-defined aromatic molecules, coal can be the starting point for a range of high-value materials.

Plastics can be divided into two major classes: commodity plastics (such as the ubiquitous polyethylene) characterized by high volume and low cost; and engineering plastics, which may be of higher cost but also have greater durability and can be competitive with metals, ceramics, or glasses. Many engineering plastics are based on aromatic structures.

Polyester materials are the fastest growing market, both in the United States and worldwide. Probably the most familiar example is poly(ethylene terephthalate) or PET, widely used for soft drink bottles and video tape. Poly(ethylene naphthalate) or PEN, is an analog of PET in which the aromatic backbone is 2,6-naphtha-
PEN is superior to PET in physical properties and will be used for the next generation of photographic film and video tape. PEN films or tapes can be much thinner, yet at the same time much stronger, than PET articles. The commercialization of PEN is waiting for a low-cost route to the monomer, 2,6-naphthalenedicarboxylic acid.

Heat-resistant polymers have recently had a significant commercial impact because of their high thermal and chemical stabilities. Kapton (by Du Pont), for example, is produced from pyromellitic dianhydride and bis(4-aminophenyl) ether. The current price is about $50 per pound, which is higher than the price per ton of many coals.

Thermotropic liquid crystalline polymers containing naphthalene or biphenyl ring systems are capable of replacing metals or ceramics in many applications. Demand for these polymers in the United States is predicted to triple by 1995, and then to double from 1995 to 2000. Applications include heat-resistant cookware, automobile parts, electronics components, machine components, and composite materials.

The development of more efficient processes for making the aromatic monomer building blocks from suitable feedstocks is highly desirable. Coals are intrinsically rich in aromatics, and coal liquids are composed primarily of one- to four-ring aromatics and phenolic compounds. Coal-to-chemicals research could contribute significantly to the development of high-value aromatic monomers, according to Song and Schobert.

In a discussion of coal chemistry, Song and Schobert consider what might be done by utilizing 2,6-naphthalenedicarboxylic acid and pyromellitic anhydride, two of the hundreds of components that may be derived from coal tar.

Examination of molecular structural features of coals by standard techniques (e.g., $^{13}$C nuclear magnetic resonance spectroscopy), and computer modeling of the structures could allow selection of candidate coals having an abundance of two-ring aromatic structures and relatively few aliphatic cross-links between aromatic systems. Oxidative cleavage of the aliphatic cross-links could produce a family of naphthalene dicarboxylic acids, which can be isomerized, via the potassium salts, to the desired 2,6-acid.

The isolation of phenanthrene from coals rich in three-ring aromatic structures offers a route to the pyromellitic anhydride, via isomerization of sym-octahydrophenanthrene with shape-selective catalysts.

These are two examples of how carefully selected coal feedstocks could be combined with known organic reactions to produce valuable monomers for engineering plastics. More knowledge is needed of the principal organic structural features, especially the types of aromatic ring systems, the number of specific positions of ring substituents, and the nature of the aliphatic carbons. This should make it possible to select specific coals as starting materials and to know the specific bonds that must be cleaved. Knowledge is needed on the kinetics, mechanisms, and thermochemistry of the cleavage processes. More knowledge is needed on the porous structure of coals, both to get reagents into the coal and products out. Finally more knowledge is needed to make rational selection of appropriate solvents, catalysts, and conditions for coal reactions.
CRE GASIFIER DEVELOPED FOR TOPPING CYCLE

The topping cycle is an integrated partial gasification combined cycle system which offers potential advantages over other advanced coal-fired processes under development. Within the United Kingdom a development program is under way to develop the components of the topping cycle, leading to the establishment of demonstration and commercial units. The air blown partial gasification component is under development at the Coal Research Establishment (CRE). The gasification program has involved the construction and extended operation of a 20 bar, 12 tonne per day gasifier, laboratory-scale testing and cold-flow simulation studies. From this work preliminary designs for demonstration-scale gasifier units have been prepared.

This work was reported in a paper by J.J. Gale, et al., at the 10th Annual International Pittsburgh Coal Conference, held in Pittsburgh, Pennsylvania in September.

The gasifier component of the topping cycle is a fluidized bed system which incorporates a submerged spout. The gasifier development program has involved:

- Construction and extended operation of a 12-tonne per day pressurized fluidized-bed gasification test facility
- Program of fundamental studies to develop an understanding of the chemical and physical reactions occurring within the gasifier
- Development of a mathematical model of the gasification process

To assist scaleup a program of cold-flow simulation studies is under way to investigate particle mobility in larger scale reactors.

Pressurized Fluidized-Bed Gasification Test (PFBG) Facility

The PFBG test facility (Figure 1) consists of a 10.8-meter high refractory lined pressure vessel with an internal diameter of 0.32 meters, which expands to 0.45 meters at 6 meters above the base flange. The gasifier can operate at pressures up to 20 bar, temperatures up to 1,050°C and with fluidized-bed heights up to 6 meters. The fluidizing velocity can be varied in the range of 0.5 to 1.2 meters per second. The fluidizing media are air and steam. These gases are injected in combination through the central spout of the reactor and through the wall of the conical base section. The crushed coal (top size 3 millimeters) and limestone (top size 1 millimeter) are injected with air into the reactor via the central spout. In the gasifier the coal is gasified, producing gas, char and ash. Some of this material is elutriated from the gasifier and is then trapped in high temperature cyclones. After the first or primary cyclone, the gas can pass to two further stages of cyclones before it is cooled to 300°C in a heat exchanger prior to pressure let-down; it is then burned in an enclosed flare prior to being exhausted to atmosphere. Alternatively, the gas can be routed through the gas utilization facility. This facility can take the full gas flow from the plant after the primary cyclone and
is designed to operate up to the full plant operating pressure (20 bar). The gas utilization facility consists of:

- A gas cooler unit to reduce the gas temperature of the fuel gas from 900°C to between 400 and 600°C
- A ceramic candle filter unit containing four ceramic candles
- A half-scale turbine combustor can taken from a tuboannular type machine

The combustor can is situated on a test stand, which is operated separately from the gasification plant using a synthetic bottled gas supply.

The primary cyclone fines and the char/ash removed from the base of the gasifier are cooled, depressurized and discharged from the plant in collection bins. These materials are utilized in subsequent char combustion studies. The char combustion test work is carried out on a 1.8 megawatt circulating fluidized-bed combustor pilot plant at CRE.

The gasifier is controlled by using a computerized monitoring and control system, which also provides a data logging facility. The PFBG test facility has full gaseous diagnostic capabilities for characterization of the major, minor and trace species in the fuel gas to be analyzed. Additional specialist alkali sampling equipment, developed at CRE, is installed on the gas utilization facility. Data collation and evaluation take place off-line using specially designed software.

Pressurized Gasification Studies

Gale, et al., report that the PFBG test facility has been operated extensively, with some 1,500 hours of plant operation completed at elevated pressure. Operational availability has increased significantly during the program, due to improvements in the operational integrity of plant components, design improvements particularly to the gasifier base, and as operator familiarity has increased. In the last operational period some 500 hours of sustained operation were completed successfully before an external power failure terminated plant operations. This period of operation represents a plant availability factor on the order of 80 percent.

During the operating phase, the gasifier was operated with a number of United Kingdom high volatile bituminous coals. No ash agglomeration problems have been encountered with these coals, which indicates that the gasifier can successfully utilize the range of indigenous coals likely to be encountered.

During the operating phase, the data from over 50 test sections have been completed; this has allowed the effect of the main operating parameters on the performance of the gasifier to be determined. As a component of the topping cycle, the gasifier must achieve certain performance criteria, which are:

- A coal conversion efficiency in the range 70 to 80 percent (dry ash free basis)
- A minimum gas calorific value of 3.6 megajoules per cubic meter (wet, net)
- A sulfur retention efficiency of 90 percent with a Ca:S molar ratio of 2:1

Results achieved to date have demonstrated that these performance criteria can be attained. The main operating parameters influencing the gasifier performance have been found to be temperature and coal to air mass ratio.

Fundamental Reaction and Modeling Studies

In conjunction with the Process Development Unit (PDU) program the chemical and physical reactions occurring within the gasifier have been studied in laboratory-scale test apparatus. The types of apparatus include:

- A pressurized thermogravimetric balance, used to study the kinetics of gasification and sulfur retention
- A pressurized heated grid apparatus, to measure volatile yields and study coal swelling at pressure

The information gained in these studies has been incorporated, on a modular basis, into a mathematical model of the gasification process.

A prototype model of the gasifier has been developed that can predict gasifier performance in terms of coal
conversion efficiency and gas quality. The model has been tested against the PDU test data with good agreement between the predicted and actual plant performance data. Further refinement of the model is continuing with incorporation of the sulfur retention and ash agglomeration sub modules.

The model has been used to predict performance in a larger scale plant appropriate to the demonstration and commercial operating phases for the topping cycle. Initial predictions indicate that at both scales of operation the performance of the larger scale plant is improved over the PDU gasifier.

Cold-Flow Simulation Studies

A scaled cold model of the PFBG test facility has been constructed and operated. Particle mobility patterns in the cold model and temperature profiles in the PFBG were compared, which highlighted areas of poor particle mobility in the PFBG test facility. The cold model was then used to develop a refined base design which gave good overall particle mobility in the PFBG test facility.

To study particle mobility in larger reactors, two cold models, one 0.9-meter diameter and one 1.8-meter diameter, have been constructed and operated. The 1.8-meter diameter reactor represents the next scale of gasifier operation (15-tonne per hour) proposed for the topping cycle demonstration phase. The work completed on these cold models has allowed a base design for the 15-tonne per hour gasifier module to be determined which gives good overall particle mobility at this scale of operation. A 2.5-meter diameter scaled semi-circular cold model is being built to study base design for the 50-tonne per hour gasifier module.

Future Program

Gale, et al., expected installation of the gas utilization facility on the PFBG test facility to be complete by mid-1993. Test work on the plant will continue until mid-1994 to demonstrate combined operation of the gasifier and gas cleanup train.

Programs are in place to complete the testing of United Kingdom coals, to study the cogasification of coal and sewage sludge/biomass. This work will be complete by the end of 1994. This will then be followed by test work to demonstrate operation of the gasifier train with a range of international coals and sorbents appropriate to the full market potential of the process.

GASIFICATION PROJECTS PROGRESSING IN CHINA

SGI International Inc. (SGI) of La Jolla, California, has agreed to conduct a technical feasibility and economic evaluation for a 5,000-ton per day "Clean Coal Refinery" that would produce two clean, high quality fuels from low-rank coals in China. The agreement was signed with the Shandong Provincial Coal Bureau and the Comprehensive Utilization Corporation of Shandong Coal Industry (CUCSCI) in Shandong Province, China.

The agreement with the Chinese follows tests of samples of Shandong Province coals at SGI's Development Center in Perrysburg, Ohio. The successful tests showed that coals from the Beizhao and Wall mines in China would be candidates for SGI's technology.

Should the coal refinery be built, it would export its upgraded fuels to Asian markets including Japan, Korea, Taiwan and Hong Kong. The plant would be located near Longkou Harbor in Shandong Province. CUCSCI has agreed to provide land and coal resources.

Demand for power is expected to grow faster in East Asia than any other part of the world. China now spends about $10 billion a year on power projects, an amount expected to double by the turn of the century. And China is expected to fuel most of that growth with its huge reserves of coal. Forty percent of its new energy spending is expected to be for coal-fired power.

Additional SGI clean coal efforts in China include projects in the Shanxi and Liaoning Provinces (see the Pace Synthetic Fuels Report, December 1993, page 4-18).

In addition to the SGI projects, other coal gasification projects in China are in various stages of development.

A coal gasification plant planned in the Henan Province of China is likely to get funding from the Organization for Economic Cooperation and Development, via the Australian Government.
The gasification plant will convert local low-quality coal to a synthetic gas. The plant is expected to provide syngas to the cities of Yima, Sanmenxia, Zhengzhou and Luoyang. The project also includes a plant that will produce a clean-burning diesel and high-grade industrial wax from the syngas.

Rentech Inc. developed the gas conversion technology to be used at the plant.

PWT Asia/Pacific Warren Engineering Division, of Australia, won a contract for a coal gasification project. The coal gas will be used in hospitals and homes in the port City of Yinkou.

China's first plant to produce gasoline from coal has started up in Jincheng, Shanxi Province. The plant also will produce liquefied coal gas.

###

**PUERTOLLANO IGCC PROJECT TO BE OPERATIONAL IN 1996**

A number of European utilities formed the company ELCOGAS in order to build and operate an integrated coal gasification combined cycle powerplant in Puertollano, an industrial area in Central Spain, approximately 200 kilometers south of Madrid (Figure 1). (See the Pace Synthetic Fuels Report, December 1993, page 4-41 for other information concerning the project.) U. Sendin, et al., described the status of the project in a paper presented at the 12th Electric Power Research Institute Conference on Gasification Powerplants, held in San Francisco, California in October.

The first block to start will be the combined cycle unit burning natural gas, which is scheduled to be operational in the second quarter of 1996. The coal gasification unit should be commissioned at the end of 1996.

With a capacity of 335 megawatts, the powerplant should be the world's highest-capacity new technology plant for the foreseeable future.

**Coal Gasification Unit**

Raw coal (110 tons per hour) is crushed and fed to a conventional bowl mill, similar to those used in a pulverized coal boiler. The mill grinds the coal to a size range suitable for efficient gasification (90 percent weight less than 100 microns).

The basis of the Puertollano coal gasification island for the generation of clean gas is the PRENFLO gasifier (Figure 2).
Steam with a pressure of 127 bar is produced in the high pressure convection boiler. At the outlet from the high pressure boiler the raw gas with a temperature of approximately 380°C is passed to the convection boiler, where intermediate pressure steam is generated and boiler feedwater is preheated.

The non-leachable slag is discharged via the slag lock-hopper system.

The cooled raw gas is dedusted in two ceramic candle filter units.

The produced raw gas, approximately 180,000 cubic meters per hour, can now be sent to the desulfurization unit.

A Claus unit containing two Claus kilns produces elemental sulfur from the Claus gas of the desulfurization unit. A hydrogenation reactor treats the offgas from the Claus unit, producing a recycle gas containing H₂S which is added to the raw gas upstream the COS hydrolysis stage. The total gas treatment system is a "closed-loop" without any waste gas emission to the atmosphere.

Combined Cycle

For the gas turbine cycle, a Siemens V94.3 standard gas turbine is used, with multi-fuel burners that can burn both coal gas and natural gas. The NOₓ emission is low because nitrogen from the air separation unit is mixed with the coal gas, which is also saturated by water with low-level heat.

For the water/steam cycle steam is produced at two different locations. The gas turbine is equipped with a Heat Recovery Steam Generator (HRSG), where most of the energy of the gas turbine exhaust is used for steam production.

The sensible heat of the raw coal gas downstream of the gasifier produces steam. To minimize the temperature of the materials in the coal gas heat recovery system, which are exposed to a highly corrosive environment, only saturated steam is produced which is then introduced into the related drums of the gas turbine HRSG and superheated to steam turbine inlet conditions together with the steam produced in the HRSG.

Air Separation

The air separation unit operates as a cryogenic process. The oxygen plant consists mainly of one air separation column with a front end purification process.

This unit is designed to produce oxygen with 85 volume percent purity used in the gasifier for gasification of the raw fuel. The pure nitrogen is used for coal dust transport and inerting.

The impure nitrogen is added to the cleaned fuel gas before it enters the gas turbine's combustion chamber, reducing the heating value of the fuel gas, thus cutting NOₓ formation.

Environmental Considerations

According to Sendin, et al., the Puertollano Integrated Gasification Combined Cycle (IGCC) plant will demonstrate that it is possible to burn coal with a low environment impact as follows:

- The NOₓ emissions are controlled by the saturation of coal gas and mixing of waste nitrogen before combustion, resulting in a lower peak flame temperature.

- The SOₓ emissions are reduced more than 99 percent by desulfurization of the raw gas and elemental sulfur is recovered.

- The higher thermal efficiency (plus 10 percent compared with a new coal-fired plant) leads to a reduction in CO₂ emissions of about 10 percent compared to a modern coal-fired plant.

- The slag flows out from the bottom part of the gasifier, where the temperature is approximately 1,200°C, in a liquid form. It is then vitrified in a water quench, resulting in a glassy product that effectively encapsulates the heavy metals into a non-leachable form. Less than 1 percent of the carbon is fixed in the slag. Fly ash entrained by coal gas is recycled into the gasifier.
See Table 1 for expected atmospheric emissions from the Puertollano IGCC plant, compared with emissions from an advanced conventional powerplant.

**TABLE 1**

<table>
<thead>
<tr>
<th>STREAMS ENTERING THE ATMOSPHERE</th>
<th>Advanced Combined Cycle Powerplant</th>
<th>Conventional Powerplant with PRENFLO Gasification</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂, t/d</td>
<td>5,950</td>
<td>5,430</td>
</tr>
<tr>
<td>SO₂, t/d</td>
<td>55</td>
<td>0.5</td>
</tr>
<tr>
<td>NOₓ, t/d</td>
<td>442</td>
<td>3</td>
</tr>
<tr>
<td>Dust, kg/d</td>
<td>1,100</td>
<td>18</td>
</tr>
</tbody>
</table>

1) 250 mg/m³ n in flue gas (CEC 95)
2) 200 mg/m³ n in flue gas (CEC 95)
3) 50 mg/m³ n in flue gas (CEC 95)

KOBRA PROJECT USING HTW GASIFIER SCHEDULED FOR COMMISSIONING IN 1996

Rheinbraun’s High-Temperature-Winkler (HTW) process, i.e., fluidized-bed coal gasification, has been demonstrated in a 150-psi, 720-ton per day plant for synthesis gas production. With the object of developing the HTW process for use in combined cycle powerplants, Rheinbraun operated a HTW pilot plant at an elevated pressure of 370 psi from November 1989 to September 1992. During nearly 10,000 operating hours, gasification tests with oxygen and air and different coal types were completed. Both hard and brown coals could be gasified with both oxygen and air.

The KoBra (combined cycle powerplant with integrated HTW brown coal gasification) project, with a gross electrical output of 367 megawatts and a single-train air blown gasifier is scheduled for commissioning in August 1996.

The HTW process and the KoBra project were discussed by W. Adlhoch, et al., in a paper presented at the 12th Electric Power Research Institute Conference on Gasification Powerplants, held in San Francisco, California in October.

**HTW Coal Gasification Process**

The main characteristics of the HTW technology are:

- Gasification at pressures up to 450 psi
- Favorable process configuration in terms of energetic efficiency with moderate temperatures below the ash softening point
- Significant reduction in specific oxygen requirement
- Gasification with either oxygen or air
- High yield of chemical energy in the fuel gas corresponding to some 80 to 85 percent of the coal feed (cold gas efficiency)
- Economical processing of high-ash coals
- High tolerance to variations in coal quality as well as stable performance with high inherent safety due to a large carbon inventory in the gasifier

The coal gas produced in this way may be used as synthesis gas in the chemical industry, as reducing gas in the metallurgical sector, or as fuel gas.

**KoBra Concept**

The characteristic features of the KoBra concept are:

- Thermodynamically favorable coal drying of 12 percent residual moisture using the WTA (fluidized-bed drying with internal waste heat utilization) process developed by Rheinbraun
- Complete utilization of the dried coal
- Efficient purification of the product fuel gas under pressure, thus eliminating the need for any flue gas treatment
- Gas and steam turbine process with unfired heat recovery steam generator
- Extensive utilization of the heat obtained in cooling of the process gas in the power generation process
Utilization of the residual coke contained on gasifier ash (gasifier bottom product) and of the dry dust by fluidized-bed combustion

The KoBra demonstration plant will be located on the site of the Goldenberg power station at Hurth, southeast of Cologne, Germany.

The essential elements of the KoBra powerplant include the following:

- WTA drying
- HTW gasification
- Gas turbine

WTA Drying

The pit-wet Rhenish brown coal to be used in this powerplant contains between 40 and 60 percent moisture. Gasification of coal with such a high water content would be extremely disadvantageous from an energy efficiency point of view. Predried coal containing only about 12 percent residual water is therefore used as a feedstock for the gasification process.

The raw brown coal is heated in a preheater to about 65°C and then fed continuously to the fluidized-bed drier operating at about 110°C. The dried brown coal is continuously withdrawn from the drier and cooled to below 60°C. The water vapor expelled from the coal is dedusted in an electrostatic precipitator and then split into two streams. One of these part-streams is returned to the drier via a circulating compressor for fluidizing the bed. The other part-stream is compressed in a vapor compressor thus acting as a heat pump, and admitted to the immersed heat exchanger of the drier where it condenses, transferring its heat to the brown coal in the process. The condensate is used for preheating the brown coal.

The advantages of the WTA process over rotary tube driers are:

- By using the heat of condensation of the vapors for drying and the sensible heat of the vapor's condensate for preheating the raw brown coal, the energy requirements are cut by half
- Virtually no emissions of any pollutants
- Higher capacity per unit

HTW Coal Gasification

In the HTW gasifier the gasification agents (oxygen/steam and/or air), are fed via nozzles arranged at various levels (Figure 1). The lower part of the gasifier is conically tapered toward the bottom discharge. Above the fluidized bed there is the so-called entrained-gasification zone, where temperatures are normally higher than in the fluidized bed. A variable supply of the gasification agents to the fluidized bed and to the entrained-gasification zone allow the fluidization and reaction conditions to be adapted

**FIGURE 1**

**HIGH-TEMPERATURE WINKLER GASIFICATION TECHNICAL FEATURES**

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separately to operational requirements and raw material properties. A special feature of the HTW process is the cyclone/recirculating pipe system which operates without mechanical installations or locking devices. The dust separated in the cyclone is returned via the recirculating pipe directly into the fluidized bed, where it again takes part in the reaction.

Gas Turbine

A Siemens/KWU type V94.3 gas turbine, the largest of the .3 series, will be used for the KoBra demonstration plant.

All turbines of the .3 series comprise a 17-stage compressor with a pressure ratio of 16 and four adjustable rows of guide vanes, a 4-stage turbine with axial exhaust, external cooling of the cooling air for the first row of rotor and stator blades, two horizontal combustion chambers with low-NO burners and a turbine inlet design temperature of 1,160°C. Each combustion chamber is equipped with eight burners.

A flowsheet for the KoBra demonstration plant is shown in Figure 2.

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BUGGENUM IGCC PLANT READY FOR DEMONSTRATION

In 1989, the Dutch Electricity Generating Board, N.V. Sep, started a project to demonstrate that the Integrated Coal Gasification Combined Cycle (IGCC) concept is a viable commercial option as an alternative to conventional coal firing for electricity generation. The Board decided to build a 250-megawatt IGCC demonstration unit at the existing coal-fired power station at Buggenum. For the gasification process, the Shell technology was selected.

The project will be operated during a demonstration phase by Demkolec B.V., a development partnership of N.V. Sep. Startup was expected to be before the end of 1993. After a 3-year demonstration program (1994-1996) the unit will be opened as a commercial powerplant.

Information on the project was presented in a paper by H.A. Droog, et al., at the 12th Electric Power Research Institute Conference on Gasification Powerplants, held in San Francisco, California in October.

Technological Aspects

The gasification technology for the Buggenum plant is based upon a Shell license, covering the plant design and process guarantees for the gasification, desulfurization and water purification sections of the IGCC plant.

The heart of the gasification section is the gasifier and syngas cooler, with a capacity of 2,000 tons of coal per day. The gasifier will be operated with oxygen with a purity of 95 percent. The solids removal facility consists of a cyclone and a ceramic filter. Fly ash is
recycled to the gasifier via the coal mills. The syngas cooler generates medium-pressure (MP) and high-pressure (HP) steam, both slightly superheated.

The oxygen for gasification and nitrogen for the pressurization of the pulverized coal is obtained from the Air Separation Unit (ASU). The remaining nitrogen from the ASU is used to dilute the clean coal gas.

After fly ash is removed, the coal gas is scrubbed with water to remove halogens and other water soluble components. The gas is then fed to a HCN-COS converter and subsequently desulfurized in a selective absorption process (Sulfinol-M). Virtually all the sulfur in the coal ends up in the Sulfinol-M solvent. This H,S-rich solvent is stripped, and H,S is converted into elemental sulfur in a Claus/SCdT unit. The Claus unit is operated with oxygen and will also remove traces of NH3 and HCN from the wastewater strippers.

The clean coal gas is subsequently mixed with dilution nitrogen and saturated with water vapor. The heating value of the coal gas is thereby reduced from approximately 11,000 kilojoules per kilogram down to 4,300 kilojoules per kilogram. The diluted coal gas is burned in the gas turbine, generating 156 megawatts. The formation of thermal NO emitted by the gas turbine is purely thermal NOx, as the fuel bound nitrogen in the form of NH3 and HCN was removed by the coal gas purification process.

The economizers of the waste heat boiler provide both the gasifier/syngas cooler section and the evaporators of the waste heat boiler itself with feed water. The MP-steam (MP-steam from the gasifier mixed with cold reheat steam) and HP-steam are both superheated to 510°C in the waste heat boiler. This is the most cost-effective way to superheat the steam generated by the gasification section. The steam turbine, consisting of HP-, MP- and LP-sections, generates 128 megawatts.

The wastewater treatment plant receives water from the wet gas scrubbing system and the water system of the slag bath. Heavy metals and fluorides will be precipitated, and will have to be disposed as chemical waste. Because the plant has been designed for zero discharge to the environment, the remaining water containing chlorides will be evaporated. Water vapor is condensed and reused, and the salt of a relatively high purity will remain.

Integration Aspects

The integration concept of the Buggenum plant is characterized by two aspects (Figure 1):

Gas Side Integration--The gas turbine, the air separation plant and the coal gasification unit are interconnected. The gas turbine supplies part of its compressed air to the air separation plant, which in turn supplies oxygen to the coal gasification unit, and nitrogen for coal pressurization and dilution of the coal gas.

Steam Side Integration--Heat in the gasifier/syngas cooler sections is transferred into high-pressure and medium pressure steam, which is directly fed into the steam system of the combined cycle unit.

Environmental Aspects

The overall desulfurization efficiency is over 97.85 percent and NOx production is lower than 75 grams per gigajoule of coal (permit values). Dust emissions can almost be neglected. Maximum emission levels per kilowatt-hour net electricity production are as follows:

- SO2, 0.22 grams per kilowatt-hour
- NOx, 0.62 grams per kilowatt-hour
- Dust, 0.007 grams per kilowatt-hour

The remaining products of the plant are:

- Slag (90 percent of the ash content of the coal)
- Fly ash (10 percent)
- Elemental sulfur
- Salt
- Sludge

The plant has no process wastewater discharge.
FIGURE 1
ICGCC DEMONSTRATION PROJECT INTEGRATION CONCEPT

SOURCE: DROOG, ET AL.

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ENVIRONMENT

FUGITIVE EMISSIONS AT COOL WATER WERE LOW

The Cool Water Coal Gasification Program (CWCGP), located in the Mojave Desert region of Southern California, was the first commercial demonstration of integrated gasification combined cycle technology to produce electricity.

The CWCGP conducted a Leak Detection and Repair Program (LDARP) to periodically monitor fugitive emissions from process equipment such as valves, flanges, pump and compressor seals, vents, relief valves, and open-ended lines. The results of this program were reported in a paper by C.O. Rueter, et al., of the Radian Corporation and Texaco Syngas, Inc., at the 10th Annual International Pittsburgh Coal Conference, held in Pittsburgh, Pennsylvania in September.

Fugitive emissions were monitored on a quarterly schedule for 18 months. Because of the low emission rates from the CWCGP facility, the monitoring frequency was reduced in 1988 to twice a year. Typically, monitoring was conducted daily for approximately 2 weeks during each quarterly or semi-annual monitoring period.

Carbon monoxide, hydrogen sulfide, ammonia, and volatile organic compounds were monitored during the LDARP. The monitored streams were grouped into the following classifications: syngas, acid gas, gray water liquid, wastewater liquid, hydrocarbon liquid, and refrigerant (NH₃).

Syngas (SG) sources included both raw and clean SG streams. The acid gas designation applied to the acid gas from the Selexol unit as well as the overhead streams from flash drums, absorbers, and strippers in the SCOT/Claus, sour water stripper, and particulate scrubbing areas.

Gray water described the liquid separated from the slag and the clarified scrubber water used to remove particulates from the SG stream. Wastewater liquid included all process condensates from the gas cooling, Selexol, and SCOT areas.

The only hydrocarbon liquid streams in the plant were the solvents used to extract sulfur compounds. These included the proprietary solvent used on the Selexol unit and the methyldiethanolamine used in the SCOT unit. Finally, the refrigerant streams were present only in the Selexol unit, where pure NH₃ was used to chill the lean Selexol solvent.

Those sources requiring maintenance were repaired on-line when possible. On-line repair usually involved routine tightening and/or adjustment of the packing or seals.

Approximately 63 percent of the leaks were successfully repaired on-line, and a maintenance program reduced emissions 60 to 99.9 percent.

Source Monitoring Results

According to Rueter, et al., when the leaks were categorized by source type, 85 percent (183 out of 216) of the leaks were found to be from valves. Coincidentally, when categorized by service category, an identical number of leaking components were found to be in SG service. Valves in SG service accounted for 91 percent of the valve leaks and for 77 percent of all leaking sources. Soot-blower valves, isolation valves in the soot-blower system, and equipment associated with the soot-blower compressor were the dominant sources of fugitive emissions, particularly of CO.

Of the 173 valve leaks found during the six periods when monitoring of the main gasifier was conducted, 106 (61 percent) were associated with the soot-blower system. Overall, of the 200 leaks from all source types found during the six periods, 114 (57 percent) were associated with the soot-blower system. Only 16 leaking sources (including 10 valves and 2 connections in SG service) were found during the two monitoring periods when the quench gasifier was operating.

Other valves in SG service that accounted for most of the non-soot-blower sources were pressure control valves, pressure differential indicators, and gate valves associated with level glasses and level transmitters (usually the upper valve).

Very few of the leaking sources were found to repeatedly leak at levels higher than 1,000 ppm by volume. All of the components that leaked more than once were valves in SG service. Only 40 valves leaked more than one time; 24 of these were in the soot-
blower system. The total number of SG valves monitored during each period was about 260.

Estimation of Emission Rates

Emission rates of CO, NH\textsubscript{3}, and H\textsubscript{2}S for each quarterly or semi-annual monitoring period were estimated. The rates were calculated from measurements taken before maintenance, and they apply to the total population of sources. The results are shown in Table 1.

Emission rates seem to be more a function of the type of source leaking during the respective monitoring periods than of the number of leaking sources. For instance, the H\textsubscript{2}S emission rate was high during the second half of 1988. This high rate was primarily related to a leaking pump in Selexol solvent service, so its H\textsubscript{2}S emissions were higher than from most sources.

###

ENVIRONMENTAL IMPACTS AT WABASH RIVER GASIFICATION PROJECT ADDRESSED

Coal gasification can assist coal burning utilities in reducing sulfur dioxide emissions as mandated by the Clean Air Act Amendments of 1990 (CAAA). The gasification process can be utilized in several applications, including "repowering" existing coal-fired facilities as well as new "greenfield" projects. Destec Energy, Inc. has been studying the environmental benefits and permitting of the repowering application at PSI Energy's Wabash River station. The environmental impact of air, water, solid waste, trace hazardous air pollutants, and fuel sources have been considered. The results were discussed in a paper presented by W.S. Lessig and J.D. Frederick at PowerGen '93 Americas, held in Dallas, Texas in November.

Background

The Wabash River coal gasification repowering project, a joint venture of Destec Energy, Inc. and PSI Energy, Inc. is constructing a Coal Gasification Combined Cycle (CGCC) powerplant. The project is part of the United States Department of Energy's (DOE) Clean Coal Technology Round IV Program. Construction of the CGCC powerplant was initiated in the third quarter of 1993.

This CGCC repowered plant will provide a nominal 262 megawatts of power, and when operational it will be the largest single-train CGCC powerplant in operation in the world.

<table>
<thead>
<tr>
<th>Monitoring Period</th>
<th>CO</th>
<th>H\textsubscript{2}S</th>
<th>NH\textsubscript{3}</th>
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<tr>
<td>Third Quarter 1986</td>
<td>11</td>
<td>7.0E-04</td>
<td>4.1E-01</td>
</tr>
<tr>
<td>Fourth Quarter 1986</td>
<td>3.1</td>
<td>8.6E-05</td>
<td>5.2E-01</td>
</tr>
<tr>
<td>First Quarter 1987</td>
<td>0.52</td>
<td>2.3E-04</td>
<td>1.1E-02</td>
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<tr>
<td>Second Quarter 1987</td>
<td>3.8</td>
<td>2.0E-03</td>
<td>2.4E-03</td>
</tr>
<tr>
<td>Third Quarter 1987</td>
<td>5.3</td>
<td>4.9E-04</td>
<td>3.0E-01</td>
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<tr>
<td>Fourth Quarter 1987</td>
<td>4.6</td>
<td>6.3E-03</td>
<td>2.1E-02</td>
</tr>
<tr>
<td>First Half 1988</td>
<td>4.6</td>
<td>2.6E-03</td>
<td>8.0E-03</td>
</tr>
<tr>
<td>Second Half 1988</td>
<td>6.4</td>
<td>4.2E-03</td>
<td>2.0E-03</td>
</tr>
<tr>
<td>Average</td>
<td>4.9</td>
<td>2.1E-03</td>
<td>1.6E-01</td>
</tr>
</tbody>
</table>

*Quench gasifier in operation*
PSI's Wabash River Station is targeted by the CAAA to achieve significant SO$_2$ emission reductions by the year 2000. Repowering targeted generating facilities with clean coal technologies is specifically recognized in the CAAA as an emission-reduction option for electric utilities. Repowering with advanced coal gasification technology provides environmental benefits compared to existing coal-fired technologies and is a viable compliance option for electric utilities.

**Efficiency**

CGCC has a significant efficiency advantage over conventional coal-based technologies, as shown in Figure 1. By utilizing a combined cycle in conjunction with coal gasification, CGCC units can take advantage of the combined cycle's high efficiency, which promises to improve as gas turbine technology improves. Existing conventional coal-based technologies utilizing the Rankine cycle are asymptotically reaching their theoretical efficiency limit, thereby reducing the likelihood for improvements in the future.

CGCC technology, with its high efficiencies, is well suited to address concerns about global warming. CGCC requires about 15 percent less coal and produces 15 to 20 percent less carbon dioxide than new pulverized coal units with flue gas desulfurization (PC/FGD) or fluidized-bed combustion (FBC) units.

**Process Description**

In CGCC, coal is first ground with water to form a slurry. The slurry is then pumped into a gasification vessel where oxygen is added to form a hot, raw gas through partial combustion. The hot, raw gas is then cooled in a high-temperature heat exchanger to generate high pressure steam. The gas is then treated to remove particulates, sulfur and other impurities.

In the Wabash River plant, the synthetic fuel gas (syngas) is piped to a GE Frame 7FA combustion turbine generator rated at 192 megawatts. A heat recovery steam generator recovers gas turbine exhaust heat to produce high pressure steam. This steam and the steam generated by the high temperature heat exchanger in the gasification process is used to power an existing steam turbine generator in PSI's plant to produce an additional 105 megawatts. Figure 2 represents an overview of the various products and emission points related to the project.
Air Emissions

This plant is designed to substantially outperform the standards established in the CAAA for the year 2000, say Lessig and Frederick. The Destec technology will remove in excess of 98 percent of the sulfur in the coal. For example, SO\textsubscript{2} emissions are expected to be less than 0.02 pounds of SO\textsubscript{2} per million BTU of fuel with a coal sulfur content of 2.5 percent. NO\textsubscript{x} emissions from the project are expected to be 0.08 pounds per million BTU. On a per kilowatt-hour basis, CO\textsubscript{2} will be reduced by 21 percent from the existing boiler as well, because the repowered unit will be more efficient than current coal-based technologies.

Table 1 summarizes the expected emissions for the Wabash River coal gasification repowering project. For comparison, the table also shows the actual emissions from the pulverized coal boiler which will be removed from service as a result of the project.

Carbon monoxide (CO) emissions may be produced as a result of incomplete combustion, and minute quantities may occur as fugitive emissions.

Particulate matter (PM) emissions from the project are expected to be 0.01 pounds per million BTU.

Volatile organic carbon (VOC) emissions from the project are expected to be less than 0.003 pounds per million BTU.

As with any emission of SO\textsubscript{2}, small quantities of sulfuric acid mist emissions may be generated, and reduced sulfur species emissions may arise as a result of equipment leaks (fugitive emissions) or incomplete oxidation.

Emissions of trace quantities of CAAA hazardous air pollutants are expected to include trace metals, trace organics, polycyclic organic matter, reduced sulfur species, hydrogen chloride, hydrogen fluoride, and radionuclides. Total hazardous air pollutants emissions are estimated to be 7.0 tons per year.

Wastewater

Wastewater streams generated by the project will include unrecycled sour water, run-off from the coal storage pile, cooling tower and boiler blowdown, classifier sludge, filter backwash, demineralizer wastes, oxygen unit condensate, flushes and purges from equipment maintenance, the "first flush" from storm event precipitation in the process area, and treated domestic sewage. After treatment and temporary storage in a new process wastewater pond, these streams will be commingled with PSI's Wabash station ash sluice water before discharging to the river. The overall volume of effluent discharged from the station will increase due to the increased cooling water requirements of the repowered Unit 1 steam turbine. Stormwater will be detained for settling in a new stormwater pond.

### TABLE 1

<table>
<thead>
<tr>
<th></th>
<th>SO\textsubscript{2}</th>
<th>NO\textsubscript{x}</th>
<th>CO</th>
<th>PM</th>
<th>PM-10</th>
<th>VOC</th>
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<tr>
<td>CGCC Emissions</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Gasification Block Tons/Year</td>
<td>23</td>
<td>18</td>
<td>124</td>
<td>25</td>
<td>20</td>
<td>12</td>
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<tr>
<td>Power Block Tons/Year</td>
<td>204</td>
<td>774</td>
<td>374</td>
<td>46</td>
<td>42</td>
<td>13</td>
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<tr>
<td>Total CGCC Tons/Year</td>
<td>227</td>
<td>792</td>
<td>498</td>
<td>71</td>
<td>62</td>
<td>25</td>
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<tr>
<td>Emission, Lbs/MWh</td>
<td>38.2</td>
<td>9.3</td>
<td>0.64</td>
<td>0.85</td>
<td>0.85</td>
<td>0.03</td>
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<tr>
<td>Unit 1 Boiler</td>
<td>0.21</td>
<td>0.75</td>
<td>0.47</td>
<td>0.07</td>
<td>0.06</td>
<td>0.02</td>
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<td>CGCC</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Emissions, Lbs/MMBTU</td>
<td>3.1</td>
<td>0.8</td>
<td>0.05</td>
<td>0.07</td>
<td>0.07</td>
<td>0.003</td>
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<tr>
<td>Unit 1 Boiler</td>
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<td>0.08</td>
<td>0.05</td>
<td>0.01</td>
<td>0.01</td>
<td>0.003</td>
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<td>CGCC</td>
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<td></td>
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</tr>
</tbody>
</table>
The pollutant concentrations in the project wastewater will be below state water quality standards.

**Solid Waste and Byproducts**

CGCC produces less solid waste and byproducts than conventional coal technology, as shown in Figure 3. The principal byproducts, slag and elemental sulfur, can be marketed. The largest-volume solid stream produced by the project will consist of gasifier slag. The quantity of slag produced is a direct function of the ash content in the coal. The slag will contain most of the mineral matter entering with the coal feed.

Extensive testing of slag produced by a similar gasification facility has demonstrated that it is not considered a hazardous waste as defined under federal and state rules. The slag is not characteristically hazardous; it is not ignitable, corrosive, or reactive, and does not leach metal or organic concentrations in excess of the toxicity characteristics. The slag is not a listed waste.

Miscellaneous non-hazardous solid waste, including scrap material, wood, etc., will be disposed of in an authorized off-site landfill. Non-hazardous wastes of an industrial nature which are not acceptable for municipal landfilling will be disposed of at a state-authorized industrial non-hazardous waste landfill.

The project will also produce small quantities of hazardous wastes, most likely in volumes less than 2.2 tons per month.

**Environmental Review Process**

In May 1993, DOE completed its comprehensive environmental review of the project and issued an Environmental Assessment and Finding of No Significant Impact in accordance with the requirements of the National Environmental Policy Act.

###

COAL AGGLOMERATION PROCESS CLEANS UP TAR AT GAS PLANT SITES

The Electric Power Research Institute (EPRI) has sponsored research to develop inexpensive technology for cleanup of tar contaminated soils at old Manufactured Gas Plant (MGP) sites. The technology was developed by the Alberta Research Council (ARC) in Edmonton, Alberta, Canada.

The coal agglomeration process was discussed in a paper by H.E. Lebowitz, of Fossil Fuel Sciences, and C.J. Kulik, of EPRI. The paper was presented at the American Institute of Chemical Engineers Summer National Meeting, held in Seattle, Washington in August.

**EPRI Process Description**

In the EPRI process, the tar contaminated soil is mixed with a coal water slurry in a rotating tumbler. The tar and oil are transferred from the soil to the coal, and micro-agglomerates are formed. Volatiles (benzene, toluene, xylene, and etc.) are vaporized and catalytically burned. The effluent from the tumbler is screened. The coal and fine soil (screen undersize) are carried to a flotation cell where they are separated. The size of the coal particles is increased by further agglomeration. The products are de-watered and removed as fine clean soil, which is returned to the earth; and as agglomerates, which are taken to the powerplant for combustion.
MGP sites also contain larger coke particles which retain oil and are mixed with the soil and rocks. The coke and rocks are removed together on the screen at the exit of the tumbler and are then gravity separated in jigs. The float fraction containing the coke is ground and recycled to the tumbler, where it will behave like the coal and end up in the agglomerates. The rocks are clean, are removed as coarse clean soil, and are buried with the fine clean soil.

Table 1 shows a rough material balance for an MGP contaminated soil initially containing 5 percent tar. Table 2 shows the typical tar content of the various products. Tar is measured as moisture free, toluene extractable material. The process has been tested on a range of different samples, as shown in Table 3. In general, oil contaminated soils produce a slightly cleaner soil than their more complex MGP cousins.

**Simplified Process**

A simplified variant of the process omits separation of the coal from the soil. For many sites, particularly

**TABLE 1**

| Material Balance for EPRI Soil Cleaning Process |

<table>
<thead>
<tr>
<th>Moisture Free Product Yields per 100 Pounds of Soil (Coal free basis) From a Site with 5% Tar in the Soil</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fine Clean Soil</td>
</tr>
<tr>
<td>Coarse Clean Solids</td>
</tr>
<tr>
<td>Agglomerates</td>
</tr>
</tbody>
</table>

**TABLE 2**

| Product Quality for EPRI Soil Cleaning Process (MGP Site) |

| Fine Clean Soil - 0.1% Toluene Solubles |
| Coarse Clean Solids - 0.15% Toluene Solubles |
| Volatiles (Benzene, Toluene, Xylene) |
| Agglomerates - up to 20% Toluene Solubles - Non-hazardous |

MGP sites, the least expensive means of remediation would be combustion of the tar contaminated soil at an appropriate power station. Application of this technology would be limited, because many soils are classified hazardous under the Resource Conservation and Recovery Act due to failing the TCLP leaching test. Also, they perhaps would have an unfavorable odor and handling properties, according to the authors.

The simplified process has been simulated on the bench-scale using soil from an MGP site. A soil sample contained 0.70 weight percent of toluene soluble hydrocarbons. This corresponded to 26.9 ppm of Benzene, Toluene Extractables (BTEX). The BTEX in the TCLP leachate was 1,136 ppb and the Polycyclic Aromatic Hydrocarbons (PAHs) were 358 ppb. The treated soil was free of BTEX. The leachate from the TCLP test showed non-detectable BTEX and 49 ppb of PAHs.

**Cost**

The cost of building a 10-ton per hour plant according to the original design was estimated to be $3 million and a simplified plant would cost about half that amount. This translates to a cost of between about $40 and $80 per ton of soil, depending on the type of unit, size of plots to be remediated, and other variables.

###

SYNTHETIC FUELS REPORT, MARCH 1994
RESOURCE

U.S. COAL PRODUCTION AND RESERVES
UPDATED


United States Coal Reserves

Proved United States recoverable coal reserves are the greatest of any single nation, and represent about 23 percent of the world total.

They are also greater than either world oil or natural gas reserves, when measured in terms of oil equivalency. In addition, they comprise about 90 percent of the fossil energy reserves in the United States.

At present rates of use, these reserves can be expected to last nearly 250 years.

The Demonstrated Reserve Base (DRB) includes all coal that has actually been measured or sampled and coal estimated from both sample measurements and reasonable geologic projections. The United States DRB is about 476 billion tons.

Not all of the DRB can be recovered, due to geological, environmental, technical or other restrictions. Estimates of the percentage of coal that can typically be recovered range from 60 percent for Eastern underground mines to 90 percent for Western surface mines. Using a conservative recovery rate of 60 percent, the

| TABLE 1 |
| OVERVIEW OF U.S. COAL INDUSTRY |

<table>
<thead>
<tr>
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<th></th>
<th></th>
<th></th>
<th></th>
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</tr>
</thead>
<tbody>
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<td>U.S. Production</td>
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<tr>
<td>(Million Short Tons)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Region</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Appalachian</td>
<td>458.8</td>
<td>457.8</td>
<td>489.0</td>
<td>464.5</td>
<td>449.4</td>
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<td>Interior</td>
<td>196.2</td>
<td>195.4</td>
<td>205.7</td>
<td>197.9</td>
<td>193.0</td>
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<td>West</td>
<td>345.3</td>
<td>342.8</td>
<td>334.4</td>
<td>318.4</td>
<td>307.9</td>
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<td>1,000.3</td>
<td>996.0</td>
<td>1,029.1</td>
<td>980.7</td>
<td>950.3</td>
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<td>Consumption by Market</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Million Short Tons)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market</td>
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<td></td>
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<tr>
<td>Electric Utilities</td>
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<td>772.3</td>
<td>773.5</td>
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<td>100.8</td>
<td>95.0</td>
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<td>Industry</td>
<td>80.4</td>
<td>81.5</td>
<td>83.0</td>
<td>82.3</td>
<td>83.4</td>
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<td>Coke</td>
<td>32.4</td>
<td>33.9</td>
<td>38.9</td>
<td>41.4</td>
<td>41.9</td>
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<tr>
<td>Total</td>
<td>995.6</td>
<td>996.7</td>
<td>1,001.2</td>
<td>991.4</td>
<td>978.7</td>
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<td>U.S. Coal Exports</td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Million Short Tons)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Type</td>
<td></td>
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<td></td>
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</tr>
<tr>
<td>Steam</td>
<td>43</td>
<td>44</td>
<td>43</td>
<td>36</td>
<td>33</td>
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<td>Metallurgical</td>
<td>60</td>
<td>65</td>
<td>62</td>
<td>65</td>
<td>62</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, MARCH 1994
The amount of recoverable reserves are estimated to be approximately 286 billion tons.

The DRB does not include resources that are inferred to exist from broad geologic knowledge of coal beds or deposits which have not yet been discovered. Estimates of the total amount of coal resources held by the United States range as high as 4 trillion tons.

The Western United States (including Alaska) contains the largest single block of coal, about 50 percent of reserves.

The nation's Interior region has the second largest coal deposit, representing about 28 percent of total reserves. This deposit occurs in several separate basins covering an area stretching from Michigan to Texas.

In the East, the most important deposits are in the Appalachian Basin. United States coal reserves are listed by state in Table 2 and by holder in Table 3.

**Coal Production**

Coal production in the United States has increased in recent years and is now the largest single source of energy production. Measured in BTU, coal accounts for about one-third of total United States energy production, compared with less than one-quarter 20 years ago.

United States coal production totaled 1 billion tons in 1992 for the second time in 3 years. An expected increase in the demand for electric power over the next 2 decades should result in a corresponding rise in coal production and consumption.

Of the 1 billion tons of coal mined in 1992, 46 percent was produced in Appalachia, 20 percent in the Interior, and 34 percent in the West. In general, an increasing percentage of total production has come from Western mines over the past 2 decades.

A total of 27 states produced coal in 1992, with the largest production occurring in Wyoming (190 million tons) and the smallest in Arkansas (37,000 tons).

United States coal production is listed by state in Table 4.

### Table 2

<table>
<thead>
<tr>
<th>State</th>
<th>Total</th>
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</thead>
<tbody>
<tr>
<td>Montana</td>
<td>119.919</td>
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<td>Illinois</td>
<td>78.117</td>
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<tr>
<td>Wyoming</td>
<td>69.298</td>
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<td>West Virginia</td>
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<td>Pennsylvania</td>
<td>29.189</td>
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<td>Kentucky</td>
<td>29.077</td>
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<tr>
<td>Ohio</td>
<td>23.892</td>
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<tr>
<td>Colorado</td>
<td>16.956</td>
</tr>
<tr>
<td>Texas</td>
<td>10.111</td>
</tr>
<tr>
<td>Indiana</td>
<td>10.111</td>
</tr>
<tr>
<td>North Dakota</td>
<td>9.590</td>
</tr>
<tr>
<td>Alaska</td>
<td>6.136</td>
</tr>
<tr>
<td>Utah</td>
<td>6.090</td>
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<td>Missouri</td>
<td>6.001</td>
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<td>Alabama</td>
<td>4.762</td>
</tr>
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<td>New Mexico</td>
<td>4.430</td>
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<tr>
<td>Virginia</td>
<td>2.546</td>
</tr>
<tr>
<td>Iowa</td>
<td>2.190</td>
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<tr>
<td>Oklahoma</td>
<td>1.587</td>
</tr>
<tr>
<td>Washington</td>
<td>1.419</td>
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<td>Kansas</td>
<td>0.977</td>
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<tr>
<td>Tennessee</td>
<td>0.843</td>
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<td>Maryland</td>
<td>0.750</td>
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<td>Louisiana</td>
<td>0.484</td>
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<td>Arkansas</td>
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<td>South Dakota</td>
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<tr>
<td>Arizona</td>
<td>0.236</td>
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<td>Michigan</td>
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<tr>
<td>Oregon</td>
<td>0.018</td>
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<tr>
<td>North Carolina</td>
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<tr>
<td>Idaho</td>
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<tr>
<td>Georgia</td>
<td>0.004</td>
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<tr>
<td>Total U.S.</td>
<td>475,597.7</td>
</tr>
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</table>
TABLE 3

MAJOR HOLDERS OF U.S. COAL RESERVES

<table>
<thead>
<tr>
<th>Holder</th>
<th>Estimated Reserves (Billion Short Tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S. Government</td>
<td>140,000</td>
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<tr>
<td>Great Northern Properties Ltd. Partnership</td>
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<tr>
<td>Peabody Holding Co. Inc.</td>
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</tr>
<tr>
<td>Consol Coal Group</td>
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<tr>
<td>Exxon Coal and Minerals</td>
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<tr>
<td>Zeigler Coal Holding Co.</td>
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<tr>
<td>Phillips Coal Co.</td>
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</tr>
<tr>
<td>Drummond Co.</td>
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<tr>
<td>AMAX Coal Industries Inc.</td>
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</tr>
<tr>
<td>The North American Coal Corp.</td>
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</tr>
<tr>
<td>Norfolk Southern Corp.</td>
<td>2,000</td>
</tr>
<tr>
<td>Entech Inc.</td>
<td>1,900</td>
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<tr>
<td>Island Creek Corp.</td>
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<tr>
<td>Texaco</td>
<td>1,700</td>
</tr>
<tr>
<td>Arch Mineral Corp.</td>
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<tr>
<td>United Coal Co.</td>
<td>1,300</td>
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<tr>
<td>BHP-Utah Minerals</td>
<td>1,200</td>
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<tr>
<td>ARCO Coal Co.</td>
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<tr>
<td>American Electric Power Service Corp.</td>
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<tr>
<td>Westmoreland Coal Co.</td>
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<tr>
<td>Western Pocahontas Ltd. Partnership</td>
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<tr>
<td>The Pittsburg &amp; Midway Coal Mining Co.</td>
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<tr>
<td>Kennecott Corp.</td>
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<tr>
<td>A.T. Massey Coal Co.</td>
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</tr>
<tr>
<td>Kerr-McGee Coal Corp.</td>
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<tr>
<td>Texas Utilities Electric Co.</td>
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<tr>
<td>Pittston Co.</td>
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<tr>
<td>Ashland Coal Inc.</td>
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</tr>
<tr>
<td>The Coastal Corp.</td>
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<tr>
<td>Rochester &amp; Pittsburgh Coal Co.</td>
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<tr>
<td>Santa Fe Pacific</td>
<td>0.718</td>
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<tr>
<td>Sun Co.</td>
<td>0.701</td>
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<tr>
<td>Cyprus Minerals</td>
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<tr>
<td>USX</td>
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<tr>
<td>BNI Coal Ltd.</td>
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<td>Addington Resources</td>
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<td>MAPCO Coal Inc.</td>
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<tr>
<td>Elk Horn Coal Corp.</td>
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<tr>
<td>Valley Camp Coal Co.</td>
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<tr>
<td>Knife River Coal Mining Co.</td>
<td>0.257</td>
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<tr>
<td>Western Fuels Association</td>
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<tr>
<td>Jim Walter Resources</td>
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</tr>
<tr>
<td>Transco Coal Co.</td>
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<tr>
<td>Anker Group Inc.</td>
<td>0.200</td>
</tr>
<tr>
<td>Colowyo Coal Co.</td>
<td>0.200</td>
</tr>
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</table>

TABLE 4

U.S. COAL PRODUCTION BY STATE
(Thousand Short Tons)

<table>
<thead>
<tr>
<th>State, Rank</th>
<th>1992 Total</th>
<th>% of Total U.S.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Wyoming</td>
<td>190,247</td>
<td>19.0</td>
</tr>
<tr>
<td>2. West Virginia</td>
<td>164,914</td>
<td>16.5</td>
</tr>
<tr>
<td>3. Kentucky</td>
<td>161,335</td>
<td>16.1</td>
</tr>
<tr>
<td>4. Pennsylvania</td>
<td>67,612</td>
<td>6.8</td>
</tr>
<tr>
<td>5. Illinois</td>
<td>59,444</td>
<td>5.9</td>
</tr>
<tr>
<td>6. Texas</td>
<td>54,589</td>
<td>5.5</td>
</tr>
<tr>
<td>7. Virginia</td>
<td>44,954</td>
<td>4.5</td>
</tr>
<tr>
<td>8. Montana</td>
<td>38,999</td>
<td>3.9</td>
</tr>
<tr>
<td>9. Indiana</td>
<td>32,045</td>
<td>3.2</td>
</tr>
<tr>
<td>10. North Dakota</td>
<td>31,697</td>
<td>3.2</td>
</tr>
<tr>
<td>11. Ohio</td>
<td>29,889</td>
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</tr>
<tr>
<td>12. Alabama</td>
<td>25,451</td>
<td>2.6</td>
</tr>
<tr>
<td>13. New Mexico</td>
<td>24,716</td>
<td>2.5</td>
</tr>
<tr>
<td>14. Utah</td>
<td>21,332</td>
<td>2.1</td>
</tr>
<tr>
<td>15. Colorado</td>
<td>18,861</td>
<td>1.9</td>
</tr>
<tr>
<td>16. Arizona</td>
<td>12,512</td>
<td>1.2</td>
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<tr>
<td>17. Washington</td>
<td>5,252</td>
<td>0.5</td>
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<tr>
<td>18. Maryland</td>
<td>3,371</td>
<td>0.3</td>
</tr>
<tr>
<td>19. Louisiana</td>
<td>3,207</td>
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</tr>
<tr>
<td>20. Missouri</td>
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<td>0.3</td>
</tr>
<tr>
<td>21. Tennessee</td>
<td>2,765</td>
<td>0.3</td>
</tr>
<tr>
<td>22. Oklahoma</td>
<td>1,944</td>
<td>0.2</td>
</tr>
<tr>
<td>23. Alaska</td>
<td>1,527</td>
<td>0.1</td>
</tr>
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<td>24. Kansas</td>
<td>363</td>
<td>*</td>
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<tr>
<td>25. Iowa</td>
<td>287</td>
<td>*</td>
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<tr>
<td>26. California</td>
<td>105</td>
<td>*</td>
</tr>
<tr>
<td>27. Arkansas</td>
<td>37</td>
<td>*</td>
</tr>
<tr>
<td>Total U.S.</td>
<td>1,000,250</td>
<td>100.0</td>
</tr>
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</table>

###

RECORD UNITED STATES COAL PRODUCTION FORECAST FOR 1994

The National Coal Association predicted in January that United States coal production in 1994 will rebound to serve new demand for steam coal at utilities and the demand to rebuild stocks sharply depleted in 1993. Production in 1994 will increase nearly 8 percent from 1993 levels to 1,033 million tons, a new record, according to the forecast.

Production in the East will increase the most (58 million tons, or 10.6 percent) to 605 million tons;
production in the West will increase to 428 million tons, a 4.4 percent increase. Both producer and consumer stocks will also increase in 1994.

Consumption of coal is expected to show an increase in 1994 due primarily to an increase in utility coal burn. Demand for domestic consumption and for export during 1994 will total 1,018 million tons, a 1.19 percent increase from the 1,006 million tons used during 1993.

The 1994 forecast is based upon the gross domestic product forecasts published late last year by the "Blue Chip Indicators." In 1994, the economy is forecast to grow at the annual rate of 2.8 percent. Unlike previous years, the growth in the economy is expected to be the result of activity for domestic consumption. While manufacturing for export remains an important factor, exports are not increasing at the same rate as in previous years.

In 1994, on-hand supplies are expected to increase as utilities attempt to replace stockpiles and as producers rebuild some stocks at the mines. Thus, production will exceed total domestic consumption and exports by about 15 million tons, to equal 1,033 million tons (76 million tons, or almost 1.5 million tons per week above 1993 levels).

Imports, which have been steady at about 3 million tons for several years increased to 6 million tons in 1993 and will remain at this new higher level in 1994.

Electric Utilities

The utility sector accounts for 89 percent of the coal consumed within the United States and just over 80 percent of total United States coal production.

Coal burn at utilities in 1994 should approximate 824 million tons, 15 million tons or 1.9 percent above the 1993 levels of 808.7 million tons. Assuming normal weather patterns, electrical generation is expected to increase by 2.0 percent in 1994. Coal’s market share will drop slightly to 56.0 percent due to an expected increase in generation from oil and gas. Nuclear is expected to decline to a 21.4 percent market share, oil and gas combined will increase slightly to 12.9 percent, and hydro generation will be steady at about 9.7 percent of total generation.

One coal-fired plant will come on-line in 1994--South Carolina Public Service Company's Cross plant. This plant is not scheduled to begin operation until November, however, so will add little to the 1994 coal burn.

Much of the increase in electricity demand last year was for residential use, where sales were up 5.9 percent, due primarily to the weather. Industrial sales increased only 1.7 percent, and commercial sales increased 3.3 percent. Given normal weather patterns, sales to commercial and industrial users should show more strength in 1994.

Statistics for electric utilities in the United States are presented in Table 1.

**TABLE 1**

<table>
<thead>
<tr>
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<tbody>
<tr>
<td>Percent Generation By:</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Coal</td>
<td>54.9</td>
<td>56.3</td>
<td>56.2</td>
<td>56.0</td>
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<tr>
<td>Oil/Gas</td>
<td>13.3</td>
<td>12.6</td>
<td>12.4</td>
<td>12.9</td>
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<tr>
<td>Nuclear</td>
<td>21.7</td>
<td>22.1</td>
<td>21.6</td>
<td>21.4</td>
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<tr>
<td>Hydro-Other</td>
<td>10.2</td>
<td>9.0</td>
<td>9.9</td>
<td>9.7</td>
</tr>
<tr>
<td>Electricity Growth Rate, %</td>
<td>0.5</td>
<td>-1.0</td>
<td>2.8</td>
<td>2.0</td>
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<tr>
<td>GDP Growth Rate, %</td>
<td>-0.7</td>
<td>2.6</td>
<td>2.8</td>
<td>2.8</td>
</tr>
<tr>
<td>Coal Consumption (mtons)</td>
<td>772.3</td>
<td>780</td>
<td>808.7</td>
<td>823.6</td>
</tr>
</tbody>
</table>

*Forecast
Non-utility generation has had a definite impact on the generation of electricity from the traditional utility. Non-utility generation has increased from 40,000 gigawatt-hours (GWH) in 1985, to 116,500 GWH in 1990, to 164,000 GWH in 1993, and an estimated 182,000 GWH in 1994. Only about 15 percent of this generation is coal fired. It is clear non-utility generation is having an effect on total coal burn, at least in the short term.

Utility stockpiles, which declined in 1993 to the lowest year-end levels since 1977-1978, will be partially rebuilt in 1994.

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STATUS OF COAL PROJECTS

COMMERCIAL AND R&D PROJECTS (Underline denotes changes since December 1993)

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 Powerplant located in Sheridan, Wyoming. The Acme facility is a 12 megawatt coal-fired steam plant, which has been idle since 1977 when it was shut down in anticipation of new power generating facilities.

APAC formed Acme Power Company, a wholly-owned subsidiary, which will bring the Acme plant up to current environmental standards with appropriate emission controls prior to bringing it back on-line. The plant will initially operate in a conventional mode, using locally purchased coal. In addition to providing revenue through electric power sales, the plant, with its modular design, will provide for a long term commercial demonstration of the desulfurizing coal gasification process which APAC has optioned.

The project will demonstrate the commercial viability of the desulfurizing gasification technology and make it ready for the retrofit of other coal-fired facilities.

The APAC coal gasification process can emphasize either acetylene production from calcium carbide or power generation, depending on the coal-to-limestone ratio used. Increasing the limestone component produces byproduct calcium carbide, from which acetylene can be produced. Increasing the coal component results in byproduct calcium sulfide.

As of August 1993, the project had been suspended indefinitely.

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-1 process. That program evolved over the years in terms of technology and product slate objectives. Kerr-McGee Critical Solvent Dashing 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 Dashing 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 MAF coal were demonstrated on bituminous coal. Similar operations with sub-bituminous coal demonstrated distillates yields of about 55 percent MAF. This represents substantial improvement over single stage coal liquefaction processes.

Tests then concentrated on testing both types of coals with the dashing 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 dopped, thereby reducing the equipment size substantially.

Recent work emphasized identifying potential cost benefits through advantageous feedstock selecting. This includes the use of lower ash (Ohio) coal and lower cost (Texas) lignite. The Ohio coal run results suggest that deep cleaning of the coal prior to liquefaction can increase distillate yield by 7-8 percent.

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STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

Work using the Amocat catalyst indicated the need to improve first stage reactor design. This led to modification of the L/D criteria which resulted in increased productivity corresponding to improved mixing. This improvement was also demonstrated with low-rank (Powder River Basin) coal. Further improvements for low-rank coal liquefaction were demonstrated using dispersed molybdenum catalyst in place of extracted catalyst in the first reaction. In addition to increasing productivity, the dispersed catalyst permits the use of a less expensive entrained flow (bubble column) reactor in place of the fluidized (ebullated) bed which is still required in the second reactor. Dosage of less than 200 ppm was effective, thus no catalyst recovery is required.

Project Cost: Construction and operating costs (through calendar 1990): $139 million

ADVANCED POWER GENERATION SYSTEM – British Coal Corporation, United Kingdom Department of Trade and Industry, European Commission, PowerGen, GEC/Alsthom (C-15)

A consortium involving British Coal Corporation, United Kingdom Department of Trade and Industry, European Commission, PowerGen, and GEC/Alsthom is carrying out a research program to develop an advanced coal fired power generation system. In this system coal is gasified in a spouted bed gasifier 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 circulating fluidized bed char combustor.

The integrated system is expected to have an efficiency of about 48 percent.

A 12 tonne per day, air blown, pressurized, spouted bed gasifier developed at the Coal Research Establishment, Gloucestershire, started operating in 1990. This provides gas to a hot gas cleaning plant and a gas turbine combustor.

At Grimethorpe, British Coal’s large scale experimental PFBC has completed a program where a coal derived gas is passed through an experimental gas turbine. In conventional PFBC, coal is burned under pressure and the hot pressurized gases are fed directly into a gas turbine. However the operating temperature of a PFBC is usually only about 850°C to avoid sintering of the ash. This comparatively low temperature at the gas turbine inlet limits efficiency.

To overcome this, British Coal engineers proposed a topping cycle. It entails burning a coal-derived fuel gas in the gas turbine combustor, at a temperature to 1,260°C or more.

The research program is funded by the United Kingdom Department of Trade and Industry, 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 Johannesberg. The plant uses six Koppers-Toizek two-headed gasifiers operating at 1,600 degrees C and atmospheric pressure to generate synthesis gas from sub-bituminous South African coal of low sulfur and high ash content. The ammonia plant, which utilizes conventional technology in the synthesis loop, has been in service since 1974 while the methanol unit, which employs ICI’s low pressure process, has been running since 1976. The plant is operating very satisfactorily at full capacity.

AECI has successfully completed the piloting of a methanol to hydrocarbons process using Mobil zeolite catalyst. The design of a commercial scale ethylene plant using this process has been completed.

AECI has also pursued development programs to promote methanol as a route to transportation fuel. Test programs include operation of a test fleet of vehicles on gasoline blends with up to 15 percent methanol, operation of other test cars on neat methanol, and operation of modified diesel trucks on methanol containing ignition promoters, trademarked "DIESANOL" by AECI. "DIESANOL" is currently being evaluated as a diesel fuel replacement in a number of countries.

AECI has completed a detailed study to assess the economic feasibility of a coal-based synthetic fuels project producing gasoline and diesel using methanol conversion technology. The results of this study were encouraging technically, but lacked economic feasibility, with the result that further work in this area has been suspended.

Project Cost: Not disclosed

AMAX/EMRC MILD GASIFICATION DEMONSTRATION – AMAX, University of North Dakota Energy and Minerals Research Center (EMRC) (C-31)

AMAX is considering a 1,000 ton per day plant at its Chinook Mine in Indiana. A fast fluidized-bed reactor will be used for mild gasification of this caking coal. It is planned to produce a diesel type fuel, as well as pure chemicals such as benzene and phenol.
AMAX conducted prefeasibility studies and concluded that favorable economics depend upon upgrading the mild gasification chars to a higher value product. This is because char has lower volatile matter content and higher ash content than the starting coal. These characteristics make char a low value utility fuel. The char will be cleaned by simple physical methods, then further processed into a metallurgical coke substitute (pellets or briquettes) and possibly to activated carbon for the pollution control industry. The location of this project offers distinct marketing advantages for these products.

A 100 pound per hour mild gasification process demonstration unit was started up at the Energy and Environmental Research Center in Grand Forks, North Dakota in the fall of 1990.

BEWAG GCC PROJECT – BEWAG AG, EAB Energie-Anlagen Berlin GmbH, Ruhrkohle Oel und Gas GmbH, and Lurgi GmbH (C-35)

BEWAG AG of Berlin, in cooperation with others listed, has started to evaluate a project called "Erection and testing of a GCC-based demonstration plant."

The project's ultimate goal is the erection of a 195 megawatt pressurized circulating fluidized bed (CFB) combined cycle powerplant, with 95 megawatts obtained from the gasification, and 100 megawatts from the combustion section. As both sections may be operated individually, the 52 megawatt gas turbine could also operate on oil or natural gas.

An engineering study to investigate the general feasibility of both pressurized CFB gasification and the coupling of pressurized CFB gasification with atmospheric CFB combustion was concluded in 1986.

A second phase component testing program, costing DM12 million and supported by the German Ministry of Research and Technology, was carried out by a working group made up of BEWAG/EAB (Berlin), Ruhrkohle Oel und Gas GmbH (Bottrop), and Lurgi GmbH (Frankfurt), under the project leadership of EAB Energie-Anlagen Berlin GmbH.

In this study, the design risks of key components were eliminated by detailed tests at pressurized charging valves and the condenser for carbonized residues. The availability of hot gas cleaning was proved with test series at electrostatic precipitators and tube filters. The now finished study allows the enlargement to a scaled up powerplant. This powerplant design shows a low grade of complexity on the gasification plant (a result of the dry procedure in gas cleaning) and minimized demand of coal and lime quality. The emission of exhaust fumes is reduced by the well known low emission of the CFB coal combustion and the high efficiency grade of the combined cycle. The only residues are flue gases and ash. The flue gas does not need to be after-treated. As a result of these characteristics, the study found a minimal risk for investment.

BHEL IGCC AND COAL GASIFICATION PROJECT – Bharat Heavy Electricals Ltd. (C-45)

BHEL’s involvement in the development of coal gasification concerns the better and wider utilization of high ash, low grade Indian coals.

As a first step, BHEL has set up a 6.2 MWe Integrated Gasification Combined Cycle (IGCC) plant with an in-house 150 ton per day moving bed gasifier integrated to a 4 MWe gas turbine and a 2.2 MWe steam turbine combined cycle plant. The plant was commissioned in 1986 and has been operated for more than 5,000 hours with the longest run of 30 days.

BHEL considers fluidized bed gasification as a long term prospective for IGCC for high ash coals. An 18 ton per day coal pilot scale Process and Equipment Development Unit (PEDU) was commissioned in 1989 for performance evaluation. In the PEDU, coal is gasified by a mixture of air and steam at around 1,173°K and a pressure of 1.013 MPa.

The PEDU has been operated for more than 1,500 hours with the longest continuous run of 168 hours. Th process and subsystem has been stabilized. The PEDU has been modified to improve carbon conversion and cold gas efficiency by recycling of cyclone ash and redesigning the distributor section of the gasifier for partial burn-up of bottom ash.

BHEL has taken up a project to retrofit a 150 ton per day fluidized bed gasifier to its existing 6.2 MWe IGCC plant by 1994. Procurement and civil work is undergoing.

Project Cost: Estimated $4 million for retrofitting fluidized bed gasifier.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

BOTTROP DIRECT COAL LIQUEFACTION PILOT PLANT PROJECT—Ruhrkohle AG, Vebo Oel AG, Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia, and Federal Minister of Research and Technology of Germany (C-60)

During operation of the pilot plant the process improvements and equipment components have been tested. The last improvement made 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 percent and an oil yield of 85 percent have been confirmed.

The project was subsidized by the Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia and since mid-1984 by the Federal Minister of Research and Development of the Federal Republic of Germany.

Project Cost: DM830 million (by end-1987)

BRITISH COAL LIQUID SOLVENT EXTRACTION PROJECT—British Coal, British Department of Trade and Industry, European Economic Community, Ruhrkohle AG, Amoco (C-70)

British Coal is operating a 2.5 tons per day pilot plant facility at its Point of Ayr site, near Holywell in North Wales utilizing its Liquid Solvent Extraction Process, a two-stage system for the production of gasoline and diesel from coal. In the process, a hot, coal-derived solvent is mixed with coal. The solvent extract is filtered to remove ash and carbon residue, followed by hydrogenation to produce a syncrude boiling below 300 degrees C as a precursor for transport fuels and chemical feedstocks. Studies have confirmed that the process can produce high yields of gasoline and diesel very efficiently—work on world-wide coals has shown that it can liquefy economically most coals and lignite and can handle high ash feedstocks.

British Coal dries and pulverizes the coal, then slurries it with a hydrogen donor solvent. The coal slurry is pressurized and heated, then fed to a digester that dissolves up to 95 percent of the coal. The digest is cooled, depressurized and filtered to remove mineral matter and 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 H₂ pressure of 25 MPa, and a temperature of 450 degrees C.
COMMERCIAL AND R&D PROJECTS (Continued)

The main objective is to evaluate and develop alternative hydroliquefaction strategies and to test the efficacy of such strategies for a small indicative range of Australian coals. The unit is capable of single stage or two-stage operation, and allows for use of disposable catalyst in stage 1 and for recycle of separated solids to stage 1, if desired. Currently, oil yields of between 35 percent and 55 percent (DAF) coal have been obtained, depending on coal feed and process type.

Batch micro-autoclaves (50 cubic centimeters) are used extensively in support of the continuous hydroliquefaction unit. Particular emphasis has been placed on matters relating to hydrogen transfer. An in-house solvent hydrogen donor index (SHDI) has been developed and has proven to be a valuable tool in process development and control, especially in non-catalytic two-stage hydroliquefaction. The research has also been concerned with the upgrading (refining) of product syncrudes to specification transport fuels. Experimental studies have included hydrotreating, hydrocracking and reforming, for the production of gasoline, jet fuel and diesel fuel. Jet and diesel fuel combustion quality requirements, as indicated by smoke point and octane 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 crude. 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.

This project has been completed. Experimental work ceased in June 1992.

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.

Brookhaven's experimental work was completed in 1990.

Project Cost: $200,000

BUGGENUM IGCC POWER PLANT -- (C-91)

A commercial prototype IGCC plant is under construction at Buggenum in the Netherlands, and startup was expected by the end of 1993. The system was designed as one process train with a combined cycle of 270 MW.

The Shell system being used is an oxygen-blown, entrained flow, slagging gasifier which uses a dry pulverized coal feed. Coal and oxygen are fed into a pressure vessel. The reaction product is a medium BTU gas consisting mainly of carbon monoxide and hydrogen, together with ammonia, hydrogen cyanide, hydrogen sulfide, and carbonyl sulfide. The downstream process consists of cooling and cleaning the gas of these toxic trace compounds. The clean synthetic gas is 62 percent CO, 32 percent H₂ and 5.5 percent inert gas. The residual sulfur content, mainly unconverted carbonyl sulfide, is less than 100 ppm by volume.

In the Shell IGCC project the gas turbine is used as a source of oxygen for the process, and nitrogen to pressurize the coal feed system. Air is bled from the compressor discharge and sent to a cryogenic air separation unit which yields oxygen to the process and makeup nitrogen to pressurize the coal transfer system.

After startup, a 3-year demonstration program (1994-1996) will be conducted. The unit will then operate as a commercial powerplant.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

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 V to build a cogeneration facility supplying 87 megawatts of electricity and 613 tons of methanol per day. The project did not receive funding, however, in Round III or IV. 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

CAMDEN CLEAN ENERGY PROJECT – Camden Clean Energy Partners Ltd. Partnership, made up of Duke Energy Corp., General Electric Co., and Air Products and Chemicals, Inc. (C-100)

A 484 megawatt advanced CGCC power plant is planned for Camden, NJ. Power from the plant will be sold to Public Service Electric and Gas Co. through an anticipated power sales agreement.

The project will demonstrate the British Gas/Lurgi (BGL) fixed-bed oxygen-blown gasifier technology in which 3,700 tons per day of Pittsburgh No. K high-sulfur coal from West Virginia is gasified to produce a clean gas that is combusted in advanced gas turbines. Turbine exhaust will be used to produce steam to drive a steam turbine in a second cycle. These two combined cycles are expected to make the CGCC plant 20 percent more efficient than a conventional coal plant, while reducing levels of SO₂, NOx and particulates to meet the most stringent environmental standards.

The CGCC component will use four BGL fixed-bed slagging gasifiers, two General Electric 7FA advanced combustion turbines and a 2,000 ton per day air separation unit. The project will also include a demonstration of a 2.5 MW molten carbonate fuel cell, which will be operated with a portion of the clean coal gases.

The project was selected under the United States Department of Energy Clean Coal Technology Demonstration Round 5. The estimated total project cost is $780 million, of which DOE will provide 25 percent.

CHARFUEL PROJECT – Wyoming Coal Refining Systems, Inc., a subsidiary of Carbon Fuels Corporation (C-110)

Wyoming Coal Refining Systems, Inc. (WCRS) has secured about half the financing required for a 150 ton per day Charfuel project. The plant would include gas processing and aromatic naphtha recovery with off-site hydrotreating and product quality verification.

The State of Wyoming has contributed $8 million and has committed to provide an additional $8.5 million in assistance, contingent on WCRS raising a certain amount of private capital. WCRS has secured over $4 million in capital and contributions.

WCRS has solicited the U.S. Department of Energy for funding under the Clean Coal Technology program but was turned down for support in Round 5 of the program in 1993.

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STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

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 has completed the design phase and has purchased most of the equipment for 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.

Wyoming officials have turned down a request from WCRS for an additional $2.5 million in loans from state funds saying that the requirement for matching funds has not been met.

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.

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 – Fundacao de Ciencia e Tecnologia—CIENTEC (C-130)

The CIGAS Process for the generation of medium BTU gas is aimed at efficient technological alternatives suitable for Brazilian mineral coals of high ash content. No gasification techniques are known to be available and commercially tested for Brazilian coals.

The CIGAS Process research and development program has been planned for the interval from 1976 to 1998. In 1977 an atmospheric bench scale reactor was built, from which were obtained the first gasification data for Brazilian coals in a fluidized bed reactor. In 1978 a feasibility study was completed for the utilization of gas generated as industrial fuel. Next the first pressurized reactor in Latin America was built in bench scale, and the first results for pressurized coal gasification were obtained.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

In 1979 the first atmospheric fluidized bed pilot scale unit was assembled (with a throughput of 7.2 tons per day of coal). In 1980 a project involving a pressurized unit for oxygen and steam began (20 atmospheres and 0.5 tons per day of coal). The plant was fully operational in 1982. In 1984 the pressurized plant capacity was enlarged to 2.5 tons per day of processed coal and at the same time air was replaced by oxygen in the atmospheric plant. This unit started processing 17 tons per day of coal.

In 1986 a unit was built to treat the liquid effluents generated throughout the process and studies on hot gas desulfurization were started in bench scale. By the end of 1988 pilot scale studies were finished. As the result of this stage, a conceptual design for a prototype unit will be made. This prototype plant will be operational in 1994 and in 1996 the basic project for the demonstration unit will be started. The demonstration unit is planned to be operational in 2001.

Project Cost: US$6.0 million up to the end of 1988. The next stage of development will require US$8 million.

CIVOGAS ATMOSPHERIC GASIFICATION PILOT PLANT — Fundacao de Ciencia e Tecnologia — CIENTEC (C-133)

The CIVOGAS process pilot plant is an atmospheric coal gasification plant with air and steam in a fluidized-bed reactor with a capacity of five gigajoules per hour of low-BTU gas. It was designed to process Brazilian coals at temperatures up to 1,000°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 Candido 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.

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-acytylene 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, but the project itself has not moved forward significantly since 1986.

Project Cost: $690 million

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COMMERCIAL AND R&D PROJECTS (Continued)

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 inland department of Antioquia.

Japan Consulting Institute is working on a feasibility study on the gasification plant and current plans are to build a US$10 to 20 million pilot plant initially. This plant would produce what 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

CORDERO COAL UPGRADING DEMONSTRATION PROJECT - Cordero Mining Company (C-170)

Cordero Mining Company will demonstrate the Carbontec Syncoal process at a plant to be built near its mine in Gillette, Wyoming. The demonstration will produce 250,000 tons per year of upgraded coal product from high-moisture, low-sulfur, low-rank coals.

The project was selected by the United States Department of Energy (DOE) in 1991 for a Clean Coal Technology Program award. DOE will fund 50 percent of the $34.3 million project cost. However, the cooperative agreement is still being negotiated.

The Syncoal process converts high-moisture subbituminous coal into a high-BTU, low-moisture product. Hot oil and flue gas serve to heat the coal and to keep it in an inert atmosphere during coal processing. The hot oil seals the surface against moisture as well as preventing surface degradation during handling.

It is expected that this upgraded coal product can be used by midwestern and eastern utilities that currently burn high-sulfur, high-rank coals to comply with stricter environmental regulations.

Near-term plans call for an expansion of the demonstration project to a 1 million ton per year plant. Long-term goals are for further expansion to produce 4 million tons per year of upgraded coal.

Project Cost: $34.3 million

COREX-CPICOR INTEGRATED STEEL/POWER PLANT - Centerior Energy Corporation, LTV Steel Company Inc., Air Products and Chemicals (C-175)

Selected under the United States Department of Energy (DOE) Clean Coal Technology Demonstration Round 5, this project will demonstrate the combined production of hot iron via the COREX process and a combined cycle power plant fueled by the export gas from the COREX process. The proposed plant will be integrated into the existing steelmaking facility at LTV Steel Company's Cleveland works.

The plant will be commercial size, producing 1.17 million tons of hot metal per year and 181 MW of power.

DOE's share of the estimated $825 million pricetag is 18 percent.

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). This project was sponsored by the European Economic Community (EEC) under two separate demonstration grants. The results obtained established the basis of a simple yet flexible process for making a gaseous fuel low in sulfur, tar and dust.

The CRE gasification process is based on the use of a submerged spouted bed. A significant proportion of the fluidizing gas is introduced as a jet at the apex of a conical base. This promotes rapid recirculation within the bed enabling caking coals to be processed without agglomeration problems. Coals with swelling numbers up to 8.5 were processed successfully. The remainder of the fluidizing gas is added through a series of jets in the cone wall to promote good particle mobility throughout the base section of the reactor.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

An atmospheric pressure process was developed for the production of fuel gas for industrial applications. A 12 tonnes per day (tpd) atmospheric pressure plant was constructed at CRE during this period. Work on the pilot plant was directed towards providing design information for a commercial scale plant. A range of commercial gasifiers with a coal throughput typically of 24 to 100 tonnes per day have been developed. To this end a license agreement was signed by OSC Process Engineering Ltd. (OSC) to exploit the technology for industrial application.

Although OSC has yet to build the first commercial unit, interest has been shown from a large number of potential clients worldwide.

The application of the process for power generation is now being investigated. Various cycles incorporating a pressurized version of the spouted bed technology have been studied and power station efficiencies up to 47 percent (lower heating value basis) are predicted. A contract with the EEC to develop a pressurized version commenced in January 1989. A 12 tonne/day pilot plant capable of operating at pressures up to 20 bar has been constructed and commissioned at CRE. Commissioning of the plant was completed in June 1990. Since that time over 1500 hours of operation have been completed successfully with a series of indigenous UK coals reflecting the range of composition available currently to the UK power station market. In addition, an extensive program of cold flow modeling studies have been completed. These and the pilot plant operational data are now being used to develop designs for commercial scale gasifiers.

The 12 tpd gasifier is now being modified to incorporate a gas cooler, a ceramic candle filter unit and a gas combustor test stand on the plant, again with EEC support. The pilot plant will then be able to carry out a comprehensive test program on the fuel gas stream components from the gasifier through to the low calorific value gas combustor. Commissioning and operation of the gasifier incorporating the fuel gas train will commence in June 1993.

CRIEPI ENTRAINED FLOW GASIFIER PROJECT – Central Research Institute of Electric Power Industry (Japan), New Energy and Industrial Technology Development Organization (C-200)

Japan's CRIEPI (Central Research Institute of Electric Power Industry) has been engaged in research and development on gasification, hot gas cleanup, gas turbines, and their integration into an IGCC (Integrated Gasification Combined Cycle) system.

An air-blown pressurized two-stage entrained-flow gasifier (2.4 ton per day process development unit) adopting a dry coal feed system has been developed and successfully operated. This gasifier design will be employed as the prototype of the national 200 ton per day pilot plant. As of late 1992, the gasifier had been operated for 2,028 hours, and tested on 20 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 1994.

CRIEPI executed a feasibility study of entrained-flow coal gasification combined cycle, supported by the Ministry of International Trade and Industry (MITI) and New Energy Development Organization (NEDO). They evaluated eight systems combining different methods of coal feed (dry/slurry), oxidizer (air/oxygen) and gas cleanup methods (hot-gas/cold-gas). The optimal plant system, from the standpoint of thermal efficiency, was determined to be composed of dry coal feed, airblown and hot-gas cleanup methods. This is in contrast to the Cool Water demonstration plant, which is composed of coal slurry feed, oxygen-blown and hot-gas cleanup systems.

For the project to build a 200 ton per day entrained-flow coal gasification combined cycle pilot plant, the electric utilities have organized the "Engineering Research Association for Integrated Coal Gasification Combined Cycle Power Systems (IGC)" with 10 major electric power companies and CRIEPI to carry out this project supported by MITI and NEDO. Basic design engineering of the pilot plant was started in 1986 and manufacturing and construction started in 1988 at the Nakoso Coal Gasification Power Generation Pilot Plant site. Coal Gasification Tests began in June 1991 with the air blown pressurized entrained-flow gasifier. Tests will begin in 1992 for the hot gas clean-up system and a high temperature gas turbine of 1,260°C combustor outlet temperature.

Project Cost: 53 billion yen

DELAWARE CLEAN ENERGY PROJECT – Texaco Syngas Inc., Star Enterprise, Delmarva Power & Light, Mission Energy (C-208)

Texaco Syngas Inc., Star Enterprise, a partnership between Texaco and Saudi Refining, Inc., Delmarva Power and Light Co. and Mission Energy have begun joint engineering and environmental studies for an integrated gasification combined cycle (IGCC) electrical generating facility. The project calls for the expansion of an existing powerplant 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.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

Completion is planned for mid-1996. The project has the potential to reduce substantially overall emissions at the Delaware City facilities, more than double the current electric output and make use of the coke byproduct from the oil refinery. The Phase I studies will require approximately one year to complete (in 1991) at an estimated cost of $6 million.

The existing powerplant would be upgraded and expanded and would continue to operate as a cogeneration facility.

Project Cost: $400 million

DESTEC SYNGAS PROJECT – Louisiana Gasification Technology, Inc. a subsidiary of Destec Energy, Inc. (C-210)

The Destec Syngas Project, located in Plaquemine, Louisiana, began commercial operations in April, 1987, operating at rates up to 105 percent of capacity. As of January 1993 the project has completed 27,400 hours on coal, has produced 29.5 trillion BTU of on-spec syngas and has reached 2,400,000 tons of coal processed. A 90-day consecutive production record of 71.2 percent capacity was reached in October 1990. A 30-day consecutive production record of 99 percent availability and 89 percent capacity factor was reached in February 1992.

At full capacity, the plant consumes 2,400 tons of coal per day providing 30 billion BTU per day of medium BTU gas. The process uses Dow-developed coal gasification technology to convert coal or lignite into medium BTU synthetic gas.

The process uses a pressurized, entrained flow, slagging, slurry-fed gasifier with a continuous slag removal system. Dow's GAS/SPEC ST-1 acid gas removal system and Unocal's Selectox sulfur conversion unit are also used. Oxygen is supplied by Air Products.

Construction of the plant was completed in 1987 by Dow Engineering Company. Each gasification module is sized to produce syngas to power 150-200 megawatt combustion turbines. The project is owned and operated by Louisiana Gasification Technology Incorporated, a wholly owned subsidiary of Houston-based Destec Energy, Inc., a subsidiary of The Dow Chemical Company.

In this application, the Destec Syngas Process and the associated process units have been optimized for the production of synthetic gas for use as a combustion gas turbine fuel. The project received a price guarantee from the United States Synthetic Fuels Corporation (now the Treasury Department) which is subject to the amount of gas produced by the project. The amount of the price guarantee is based on the market price of the natural gas and the production of the project. Maximum amount of the guarantee is $620 million.

A 30-kilowatt carbonate fuel cell pilot plant has been constructed at the Destec site, and is being subjected to endurance tests on syngas produced at Destec's coal gasification plant.

Project Cost: $72.8 million

DUNN NOKOTA METHANOL PROJECT – The Nokota Company (C-215)

The Nokota Company is the sponsor of the Dunn-Nokota Methanol Project, Dunn County, North Dakota. Nokota plans to convert a portion of its coal reserves in Dunn County, via coal gasification, into methanol and other marketable products, including carbon dioxide for enhanced oil recovery in the Williston and Powder River Basins. $20 million has been spent, and 12 years have been invested in site and feasibility studies. After thorough public and regulatory review by the state of North Dakota, air quality and conditional water use permits have been approved. The Bureau of Reclamation released the final Environmental Statement on February 26, 1988.

In terms of the value of the products produced, the Dunn-Nokota project is equivalent to an 800 million barrel proven oil reserve. In addition, the carbon dioxide product from the plant can be used to recover substantially more crude oil from oil fields in North Dakota, Montana, and Wyoming through carbon dioxide injection and crude oil displacement.

The Dunn-Nokota plant is designed to use the best available environmental control technology. At full capacity, the plant will use the coal under approximately 390 acres of land (about 14.7 million tons) each year. Under North Dakota law, this land is required to be reclaimed and returned to equal or better productivity following mining. Nokota plans to work closely with local community leaders, informing them of the types and timing of socioeconomic impact associated with this project.

Dunn-Nokota would produce approximately 81,000 barrels of chemical grade methanol, 2,400 barrels of gasoline blending stock (naphtha) and 300 million standard cubic feet of pipeline quality, compressed carbon dioxide per day from 40,000 tons of lignite (Beulah-Zap bed).

Additional market studies will determine if methanol production will be reduced and gasoline or substitute natural gas coproduced.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

Existing product pipelines and rail facilities are available to provide access to eastern markets for the project's output. Access to western markets for methanol through a new dedicated pipeline to Bellingham, Washington, is also feasible if West Coast market demand warrants.

Construction employment during the six year construction period will average approximately 3,200 jobs per year. When complete and in commercial operation, employment would be about 1,600 personnel at the plant and 500 personnel in the adjacent coal mine.

Nokota's schedule for the project is subject to receipt of all permits, approvals, and certifications required from federal, state, and local authorities and upon appropriate market conditions for methanol and other products from the proposed facility.

Project Cost:  
$2.6 billion (Phase I and II)  
$0.2 billion (CO2 compression)  
$0.1 billion (Pipeline interconnection)  
$0.4 billion (Mine)

ELSAM GASIFICATION COMBINED CYCLE PROJECT – Elsam (C-218)

Elsam, the Danish utility for the western part of Denmark, in January 1991 submitted a proposal for the construction of a 315-megawatt integrated gasification combined cycle (IGCC) powerplant using the PRENflo gasification technology. The utility proposes a 3-year test period under the Thermie program of the European Communities. The IGCC plant would be built as a joint project of the German Utility PreussenElektra and the Danish utility Sønderjylland Hojsænadningvaerk.

Elsam's proposal was dependent on financial support from the European Communities (EC). When the EC elected to provide funding to the Puertollano, Spain project, Elsam pulled out of the joint project.

Elsam is now working on two new 390-megawatt units, with 285 bar live steam pressure and a live-steam reheat temperature of 580°C. One unit can be fired with natural gas or coal; the second unit is coal fired. Commissioning of the two units is scheduled for 1998 and 1999, respectively.

ENCOAL LFC DEMONSTRATION PLANT – ENCOAL Corporation, United States Department of Energy (C-221)

ENCOAL Corporation, a wholly owned subsidiary of Shell Mining Company of Houston, Texas, received funding from the Department of Energy's Clean Coal Technology Round 3 Program for a 1,000 ton per day mild gasification plant at Shell's Buckskin Mine in Northeastern Wyoming. The government will fund 50 percent of the proposed $72.6 million total cost. The demonstration plant will utilize the LFC technology developed by SQI International.

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. Construction was completed by mid-1992. The plant had been operated for several days by the end of 1992. The plant will process 1,000 tons of coal per day and produce 150,000 barrels of liquids per year plus 180,000 tons of upgraded solid fuel.

The plant completed a 36-hour test run in June 1992 during which it operated at about 70 percent of its capacity. The solid and liquid fuels produced during the test met or exceeded the production specification.

Two companies have agreed to purchase the fuels produced at the ENCOAL facility. Wisconsin Power and Light has agreed to buy about 30,000 tons of the solid fuel for use at its coal-fired powerplants. TExPAR Energy Inc. will buy up to 135,000 barrels per year of the liquid fuel that it will market to industries.

In June 1992, Zeigler Coal Holding Company signed a letter of intent to purchase Shell Mining Company, with a target closing date in October 1992. The ENCOAL project will not be affected by the change in ownership. The United States Department of Energy has approved funding for Phase III—plant operation and testing.
COMMERCIAL AND R&D PROJECTS (Continued)

The plant was closed down for a period in 1993 for the completion of plant improvements and the installation of additional equipment. As of early 1994 it has resumed operations and testing programs.

Estimated Project Cost: $72.6 million

ESCATRON, SPAIN PFBC STEAM PLANT – Endesa (C-222)

A PFBC gas turbine was used to repower a 70 MW steam plant in Escatron, Spain. The plant burns a high-sulfur, high-ash coal which is supplied dry. Repowering enabled the plant to burn the low-grade coal and still meet emissions requirements.

FIFE IGCC POWER STATION – Fife Energy Ltd. (C-224)

Fife Energy Ltd., a Scottish power company, is developing the United Kingdom's first integrated gasification combined cycle power station in Fife, Scotland. The IGCC to be employed at the facility is based on British Gas/Lurgi's slagging gasification technology, which converts up to 94 percent of the coal input into clean syngas. The IGCC will produce less than 10 percent of the U.S. standard for emissions in new power sources, said a Fife spokesperson.

FRONTIER ENERGY COPROCESSING PROJECT – Canadian Energy Developments, Kilborn International (C-225)

The Frontier Energy project is a commercial demonstration of a state-of-the-art technology for the simultaneous conversion of high sulfur coal and heavy oil (bitumen) to low sulfur, lean burning, liquid hydrocarbon fuels plus the cogeneration of electricity for export. Two main liquid hydrocarbon products are produced, a naphtha fraction which can be used as a high value petrochemical feedstock or can be processed further into high octane motor fuel and low sulfur fuel oil that can be used to replace high sulfur coal in thermal powerplants. 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 Kilburn 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 (AOCRT) and Gesellschaft fur Kohleverfiussigung GmbH (GfK) of Saarbrucken, West Germany.

Two integrated and computerized process development units (PDUs), 18-22 pounds per hour feed rate, are currently being operated to confirm the technology in long duration runs, to generate operating data for the design of larger scale facilities and to produce sufficient quantities of clean distillate product for secondary hydrotreating studies and market assessment studies.

Canadian Energy and GfK are planning to modify an existing 10 ton/day coal hydrogenation pilot plant to the CCLC Coprocessing configuration and to use it to confirm the coprocessing technology in large pilot scale facilities while feeding North American coals and heavy oils. Data from this large pilot scale facility will form the basis of the design specification for the Frontier Energy Demonstration Project. Frontier expects the coprocessing plant to be under way in the spring of 1994.

The demonstration project will process 1,128 tons per day of Ohio No. 6 coal and 20,000 barrels per day of Alberta heavy oil. An unsuccessful application was made for Clean Coal Technology (CCT) funds in Round III. The project intends to file an application for CCT funds in Round V.

GE HOT GAS DESULFURIZATION – GE Environmental Services Inc. and Morgantown Energy Technology Center (C-228)

This project was designed to demonstrate the operation of regenerable metal oxide hot gas desulfurization and particulate removal system integrated with the GE air blown, coal gasifier at the GE Corporate Research and Development Center in Schenectady, New York.

Construction of the demonstration facility was completed by 1990 and several short duration runs were done to allow a long duration (100 hour) run to be completed in 1991. The facility gasifies 1700 pounds per hour of coal at 280 psig. Outlet gas temperature ranges from 830-1150°F.

During a 4.5 hour period in a 60 hour run the hot gas cleanup system achieved an overall sulfur removal of 95.5 percent.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

GFK DIRECT LIQUEFACTION PROJECT – West German Federal Ministry for Research and Technology, Saarbergwerke AG, and GFK Gesellschaft fur Kohleverfiussigung mbH (C-230)

For the hydrogenation of heavy oils, mixtures of heavy oil and coal (Coprocessing) 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. Within a cooperation with East Germany’s company Maschinen und Anlagenbau Grimma GmbH a counter-flow liquid-phase hydrogenation pilot plant with a capacity of 3 tons per day was built and successfully put on stream in December 1991. After the counter-flow process was principally demonstrated the project was terminated in mid-1992. GFK ceased to exist in January 1993.

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 1973. In 1975, ANG Coal Gasification Company (a subsidiary of American Natural Resources Company) was formed to construct and operate the facility and the first of many applications were filed with the Federal Power Commission (now FERC). The original plans called for a plant designed to produce 250 million cubic feet per day to be constructed by late 1981. However, problems in financing the plant delayed the project and in 1976 the plant design was reduced to 125 million cubic feet per day. A partnership named Great Plains Gasification Associates was formed by affiliates of American Natural Resources, Peoples Gas (now MidCon Corporation) Transco Inc., Transco Companies Inc. (now Transo Energy Company) and Columbia Gas Systems, Inc. Under the terms of the partnership agreement, Great Plains would own the facilities, ANG would act as project administrator, and the pipeline affiliates of the partners would purchase the gas.

In January 1980, FERC issued an order approving the project. However, the United States Court of Appeals overturned the FERC decision. In January 1981, the project was restructured as a non-jurisdictional project with the synthetic natural gas (SNG) sold on an unregulated basis. In April 1981, an agreement was reached whereby the SNG would be sold under a formula that would escalate quarterly according to increases in the Producer Price Index with a cap equal to the energy-equivalent price of No. 2 Fuel Oil. During these negotiations, Columbia Gas withdrew from the project. On May 13, 1982, it was announced that a subsidiary of Pacific Lighting Corporation had acquired a 10 percent interest in the partnership; 7.5 percent from ANR’s interest and 2.5 percent from Transco.

Full-scale construction did not commence until August 6, 1981 when the United States Department of Energy (DOE) announced the approval of a $2.02 billion conditional commitment to guarantee loans for the project. This commitment was sufficient to cover the debt portion of the gasification plant, Great Plains’ share of the coal mine associated with the plant, an SNG pipeline to connect the plant to the interstate natural gas system, and a contingency for overruns. Final approval of the loan guarantee was received on January 29, 1982. The project sponsors were generally committed to providing one dollar of funding for each three dollars received under the loan guarantee up to a maximum of $740 million of equity funds.

The project was designed to produce an average of 125 million cubic feet per day (based on a 91 percent onstream factor, i.e., a 137.5 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.

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COMMERCIAL AND R&D PROJECTS (Continued)

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 125 percent of daily 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. In March 1993, DGC installed a hydrotreater which enabled it to commence the sale of the plant's naphtha production. Other byproducts being sold from the plant include anhydrous ammonia, sulfur and liquid nitrogen. Argon, carbon dioxide and cresote are also potential byproducts.

In late 1990 DGC filed with the North Dakota State Health Department a revision to the applications to amend the Air Pollution Control Permit to Construct. The revised application defines the best available control technology to lower SOx and other emissions at the plant. In 1993, the North Dakota Department of Health approved the permit for the flue gas desulfurization system at the Great Plains Synfuels Plant. That system will reduce the sulfur dioxide from the main stack at the Synfuels Plant. In addition, the permit provides for constructing coal-lock vent scrubbers to control other pollution—particulates, total reduced sulfur and odors—from the coal-lock vents.

DGC has 4 years to complete construction of the main stack scrubber and 2 years to finish the coal-lock vent project. As of early 1994, the coal lock vent scrubbers are being fabricated.

In late 1990, DGC and DOE initiated a lawsuit against the four pipeline company purchasers contracted to buy SNG. The issues in these proceedings involve: the extent of the pipeline firms' obligations to take or pay for SNG; whether the sales price of SNG has been understated; and whether the adjustment made by DGC to the rate the plant charges the pipeline companies to transport their SNG to a point of interconnection on the Northern Border Pipeline system is in accordance with contract terms. A March 1994 trial date has been set.

Project Cost: $2.1 billion overall

GRESIK IGCC PLANT — Perusahaan Umum Listrik Negara (C-250)

Indonesia's national utility, Perusahaan Umum Listrik Negara is building a 1,500 MW capacity IGCC plant at the Gresik plant near Surabaya, Indonesia. The facility is scheduled to start up by the end of 1993.

HUMBOLT ENERGY CENTER PROJECT — Continental Energy Associates and Pennsylvania Energy Development Authority (C-265)

Greater Hazleton Community Area New Development Organization, Inc. (CAN DO, Incorporated) built a facility in Hazle Township, Pennsylvania to produce low BTU gas from anthracite. Under the third general solicitation, CAN DO requested price and loan guarantees from the United States Synthetic Fuels Corporation (SFC) to enhance the facility. However, the SFC turned down the request, and the Department of Energy stopped support on April 30, 1983. The plant was shut down and CAN DO solicited for private investors to take over the facility.

The facility has been converted into a 135 megawatt anthracite refuse-fueled integrated gasification combined cycle cogeneration plant. Gas produced from anthracite coal in both the original facility and in new gasifiers is being used to fuel turbines to produce electricity. One hundred megawatts of power will be purchased by the Pennsylvania Power & Light Company over a 20-year period. Steam is also produced which is available to industries within Humboldt Industrial Park at a cost well below the cost of in-house steam production. The combined cycle cogeneration plant has been in operation since 1990.

Project Cost: over $100 million
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

HYCOL HYDROGEN FROM COAL PILOT PLANT – Research Association for Hydrogen from Coal Process Development (Japan) (C-270)

In Japan, the New Energy and Industrial Technology Development Organization (NEDO) has promoted coal gasification technologies based on the fluidized bed. These include the HYBRID process for high-BTU gas making and the low-BTU gas making process for integrated combined cycle power generation. NEDO has also started to develop coal gasification technology based on a multipurpose coal gasifier for medium-BTU gas.

The multipurpose gasifier was evaluated as a key technology for hydrogen production, since hydrogen is the most valuable among coal gasification products. NEDO decided to start the coal-based hydrogen production program at a pilot plant beginning in fiscal year 1986. Construction of the pilot plant in Sodegaura, Chiba was completed in August, 1990. Operational research was to begin in 1991 after a trial run.

The key technology of this gasification process is a two-stage spiral flow system. In this system, coal travels along with the spiral flow from the upper part towards the bottom because the four burner nozzles of each stage are equipped in a tangential direction to each other and generate a downward spiral flow. As a result of this spiral flow, coal can stay for a longer period of time in the chamber and be more completely gasified.

In order to obtain a higher gasification efficiency, it is necessary to optimize the oxygen/coal ratio provided to each burner. That is, the upper stage burners produce reactive char and the lower stage burners generate high temperature gas. High temperature gas keeps the bottom of the gasifier at high temperature, so molten slag falls fluently.

The specifications of the pilot plant are as follows:

<table>
<thead>
<tr>
<th>Spec</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal feed</td>
<td>50 ton per day</td>
</tr>
<tr>
<td>Pressure</td>
<td>30 kg/cm²</td>
</tr>
<tr>
<td>Temperature</td>
<td>About 1,800°C</td>
</tr>
<tr>
<td>Oxidant</td>
<td>Oxygen</td>
</tr>
<tr>
<td>Coal Feed</td>
<td>Dry</td>
</tr>
<tr>
<td>Slag Discharge</td>
<td>Slag Lock Hopper</td>
</tr>
<tr>
<td>Refractory Lining</td>
<td>Water-cooled slag coating</td>
</tr>
<tr>
<td>Dimensions Outer Pressure Vessel</td>
<td>2 Meters Diameter, 13.5 Meters Height</td>
</tr>
<tr>
<td>Carbon Conversion</td>
<td>98 Percent</td>
</tr>
<tr>
<td>Cold Gas Efficiency</td>
<td>78 Percent</td>
</tr>
<tr>
<td>1,000 Hours Continuous Operation</td>
<td></td>
</tr>
</tbody>
</table>

The execution of this project is being carried out by the Research Association for Hydrogen from Coal Process Development, a joint undertaking by nine private companies, and is organized by NEDO. Additional research is also being conducted by several private companies to support research and development at the pilot plant. The nine member companies are:

- Idemitsu Kosan Co., Ltd.
- Osaka Gas Co., Ltd.
- Electric Power Development Company
- Tokyo Gas Co., Ltd.
- Japan Energy Corporation
- Toho Gas Co., Ltd.
- The Japan Steel Works, Ltd.
- Hitachi, Ltd.
- Mitsui SRC Development Co., Ltd.

NEDO succeeded in maintaining 1,449 hours of continuous operation and achieved the target gasification efficiencies of the HYCOL pilot plant in January 1994.

IGT MILD GASIFICATION PROJECT – Institute of Gas Technology (IGT), Kerr-McGee Coal Corporation, Illinois Coal Development Board (C-272)

Kerr-McGee Coal Corporation is heading a team whose goal is to develop the Institute of Gas Technology's (IGT) MILDGAS advanced mild gasification concept to produce solid and liquid products from coal. The process uses a combined fluidized-bed/entrained-bed reactor designed to handle Eastern caking and Western noncaking coals.

The 24 ton per day facility will be built at the Illinois Coal Development Park near Carterville, Illinois. The 3-year program will provide data for scaleup production, coproducts for testing, preparation of a detailed design for a larger demonstration unit, and the development of commercialization plans.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

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 supervise the activities of the team members.

The technology will produce a solid char that can be further processed into form coke to be used in blast furnaces as a substitute for traditional coke. Liquids produced by the process could be upgraded to make gasoline or diesel fuel or used to manufacture such materials as roofing and road binders, electrode binders, and various chemicals.

IMHEx MOLTEN CARBONATE FUEL CELL DEMONSTRATION – M-C Power Corporation, Bechtel Group, Stewart and Stevenson Services, Institute of Gas Technology (C-273)

M-C Power has a goal of bringing a market-responsive, natural gas fueled IMHEx molten carbonate fuel cell (MCFC) to the power generation industry by the end of the 1990s. The technology for this MW-Class (1 MW nominal capacity) power plant for use in distributed generation and cogeneration applications is being developed through a step-wise demonstration program which began in 1990 and will continue through 1998. M-C Power leads a team which consists of M-C Power, the Bechtel Group, Stewart and Stevenson Services, Inc. and the Institute of Gas Technology. This team provides both the market and power plant expertise for this commercialization effort.

M-C Power's IMHEx stack technology will be demonstrated in commercial-scale hardware over the next two years. A process development power plant will begin operation during 1994 at Uncal's Science and Technology Center in Brea, California. This unit will be followed by a second 250 kW, fully-integrated power plant in 1995 at a Kaiser Permanente Medical Center in San Diego, California. These power plant demonstration programs are sponsored by the U.S. Department of Energy, the Gas Research Institute, the Electric Power Research Institute, and a broad alliance of electric and gas utilities. Funding for these demonstration efforts and M-C Power's parallel technology developments has exceeded $50 million as of March 1994, while activities proposed through 1998 provide an additional $100 million toward the product design and improvement of the MW-class power plant.

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 traditional 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 percent 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 calorific value of approximately 2000 kcal/Nm³. Voest-Alpine says the pig iron quality matches that from blast furnaces, and that costs were $150 per ton in 1990.

Voest-Alpine has also recently patented several schemes involving a fluidized bed meltdown-gasifier (United States Patents 4,725,308, 4,728,360, 4,729,786, issued in 1988). Typically a fluidized bed of coke particles is maintained on top of the molten iron bath by blowing in oxygen-containing gas just at the surface of the molten metal.

Voest-Alpine has been collaborating with Geneva Steel to demonstrate the technology in the United States, however, Geneva has shelved further action on the project after failing to receive funding in the DOE Clean Coal Technology Round 3. In 1990 Virginia Iron Industries Corporation announced plans to build a COREX plant in Hampton Roads, Virginia. (See Virginia Iron Corex Project C-613).

The COREX process is being marketed as an environmentally superior method of iron making and claims significant reductions in dust, SO₂ and NOₓ emissions compared to conventional methods.

During 1990 the plant ran at 100 percent design capacity.

SYNTHETIC FUELS REPORT, MARCH 1994

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STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

K-FUEL COMMERCIAL FACILITY — K-Fuel, Inc. (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, the predecessor to K-Fuel, Inc. (KFI), 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, peat, woodwaste or other carbonaceous material 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 necessary 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 the total output of the first commercial plant built by the Heartland Fuels Corporation (HFC), a subsidiary of WP&L.

KFI, 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.

WP&L 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.

A license for the use of the K-Fuel technology on coal only in North America was issued to Heartland Fuels Corporation (HFC). HFC has reached an agreement to merge its project with the ThermoChem project, which received DOE support, and expects to announce the beginning of construction soon.

Additionally, KFI has signed an agreement with a major New York investment banking firm to scale-up the existing Gillette, Wyoming, pilot plant to produce over 200,000 tons of product which will be eligible for the Section 29 alternate fuel tax credit. Harris Group, a Denver-based engineering firm, is finalizing the engineering review and feasibility study. If proven feasible, construction of the plant will begin in late 1993 or early 1994.

Project Cost: $62 Million

KOBR A 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 desulfurized and fed to the combined cycle process with an unfired heat recovery steam generator. This project is referred to as KOBRA (in German: Kombikraftwerk mit Braunkohlenvergasung, i.e. combined-cycle power station with integrated brown coal gasification).

The capacity of the KOBRA plant will slightly exceed 300 MWe. The question of whether oxygen or air will be used as gasifying agent has not yet been decided, but irrespective of this the fuel gas will be produced in this demonstration plant by two gasifiers, each having a throughput of 1,800 tons per day of dried lignite. The gas turbine will have a rated capacity of about 200 MWe, and the overall plant is expected to reach a net efficiency of 46 percent.

Beginning of construction is scheduled for 1993 and start up in 1996. 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 1996, the orders relating to the desulfurization unit, the coal drying unit and some other large components were placed in 1990. Completion of the permit engineering is scheduled for mid-1992, so that building and operating permits can be applied for.

Of crucial importance for reaching a high overall efficiency is the coal drying system which reduces the moisture content of the raw brown coal to 12 percent. For this step, Rheinbraun's WTA process will be employed (WTA means fluidized-bed drying with internal waste heat utilization).

To demonstrate the technology, a plant having a capacity of 20 tons per hour of dried lignite will be started up in 1992 for testing purposes. Engineering of this project is being handled by Lurgi GmbH.

By the end of 1992, all process engineering criteria had been determined. The licensing application will be filed in 1993 and commissioning of the demonstration plant is expected to begin in mid-1996. At that time, a two-month trial operation will be followed by the two-year demonstration period.
COMMERCIAL AND R&D PROJECTS (Continued)

A successful test operation of the demonstration plant will provide the essential basis for the construction of commercial-scale power stations of this type. The start-up of a 600 MWe commercial-scale IGCC plant is scheduled for the turn of the century. This new generation of power stations will be characterized by a high overall efficiency, extremely low emissions, and low production costs.

LAKESIDE REPOWERING GASIFICATION PROJECT – Combustion Engineering, Inc. and United States Department of Energy (DOE) (C-320)

The project will demonstrate Combustion Engineering's pressurized, airblown, entrained-flow coal gasification repowering technology on a commercial scale. The syngas will be cleaned of sulfur and particulates and then combusted in a gas turbine (40 MWe) from which heat will be recovered in a heat recovery steam generator (HRSG). Steam from the gasification process and the HRSG will be used to power an existing steam turbine (25 MWe).

The project was selected under Round II of the Clean Coal Technology Program for demonstration at the Lakeside Generating Station of City Water, Light and Power, Springfield, Illinois. The project demonstrates airblown gasification at high efficiency with 99 percent sulfur capture and 90 percent NOx reduction. A new zinc titanate hot gas cleanup system is incorporated to provide even lower sulfur emissions.

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.

Plant design and definitive cost estimates have been developed for DOE and project review. Construction will begin in 1994, with initial operation in 1996. The demonstration period will develop O&M costs for the simplified airblown gasification system. ABB is focusing on the requirement of the electric power generation market in the design of this plant.

DOE is providing $129.4 million, or 48 percent, of the project's total cost. The remaining funds will be provided by Combustion Engineering, City Water, Light & Power, and the Illinois Department of Energy and Natural Resources.

Project Cost: $270.7 million

LAPORTE ALTERNATIVE FUELS DEVELOPMENT PROGRAM – Air Products & Chemicals, Inc., Electric Power Research Institute, and United States Department of Energy (DOE) (C-330)

Air Products and Chemicals, Inc. is proposing a 36-month program to develop technologies for the conversion of coal-derived synthesis gas to oxygenated hydrocarbon fuels, fuel intermediates, and octane enhancers, and to demonstrate the most promising technologies in DOE's Slurry Phase Alternative Fuels Development Unit (AFDU) at LaPorte, Texas. With emphasis on slurry phase processing, the program will initially draw on the experiences of the successful Liquid Phase Methanol (LPMEOH) program. See completed project “LaPorte Liquid Phase Methanol Synthesis” in December 1991 Synthetic Fuels Report for details on the LPMEOH project.

In the spring of 1992, methanol produced using the LaPorte Liquid Phase Methanol Synthesis Process out performed commercial chemical-grade methanol in diesel engine runs. In a standard 100 hour test, 2,500 gallons of raw methanol from the LaPorte Plant were run through a typical bus cycle simulation.

The alternative fuels development program aims to continue the investigations initiated in the above research program, with the principal objective being demonstration of attractive fuel technologies in the LaPorte AFDU. The focus is continued in pilot plant operations after a 12-18 month period of plant modifications. Certain process concepts such as steam injection, and providing H₂ via in situ water-gas shift, will assist in higher conversions of feedstocks which are necessary, particularly for higher alcohol synthesis.

Four operating campaigns are currently envisaged. The first will focus on increased syngas conversion to methanol using steam injection and staged operation. The second will demonstrate production of dimethyl ether/methanol mixtures to (1) give optimum syngas conversion to storable liquid fuels, (2) produce mixtures for both stationary and mobile fuel applications, and (3) produce the maximum amount of DME, which would then be stored as a fuel intermediate for further processing to higher molecular-weight oxygenates. Economic, process, and market analyses will provide guidance as to which of these scenarios should be emphasized. The third and fourth campaigns will address higher alcohols or mixed ether production.

In the laboratory, the principal effort will be developing oxygenated fuel technologies from slurry-phase processing of coal-derived syngas using two approaches, (1) fuels from syngas directly, and (2) fuels from DME/methanol mixtures. In fiscal year 1993, Air Products will demonstrate, at DOE's LaPorte Alternative Fuels Development Unit, the synthesis of methanol/isobutanol mixtures, which can be subsequently converted to MTBE. Preliminary economic analyses have indicated that isobutanol and MTBE from coal could be cost competitive with conventional sources by the mid- to late-1990s.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

Air Products has already demonstrated the unique ability of DME to act as a chemical building-block to higher molecular-weight oxygenated hydrocarbons. Air Products has also successfully developed and demonstrated a one-step process for synthesizing dimethyl ether (DME) from coal-derived synthesis gas. In this process, the reactions are carried out in a three-phase system with the catalyst suspended in an inert liquid medium. The liquid absorbs the heat that is released as the chemical reactions occur, allowing the reactions to take place at higher, more efficient rates and protecting the heat-sensitive catalysts necessary for the conversion process. This results in a 30 to 40 percent increase in the rate of methanol production.

Project Cost: $203 million FY91-FY93

LIQUID PHASE METHANOL PROCESS DEMONSTRATION - Air Products and Chemicals, Inc., Eastman Chemical Company, and U.S. Department of Energy (C-335)

Air Products and Chemicals, Inc. and Eastman Chemical Co. plan to demonstrate the production of liquid phase methanol (LPMEOH) under a U.S. Department of Energy Clean Coal Technology Round 3 award. The liquid phase methanol synthesis process is more efficient than the conventional gas phase process and is better suited for processing the gases produced by modern coal gasifiers. Producing methanol as a coproduct in combined cycle coal gasification facilities has distinct advantages. The gasifier can be run continuously at its most efficient level. During periods of low power demand, synthesis gas made by the gasifier would be converted to methanol for storage. At peak power demand, this methanol could be used to supplement the combustion turbine, thus lowering the size of the gasifier that would be required if the gasifier alone had to meet peak electrical demand.

The project was originally slated for location at the Texaco Cool Water plant in Daggett, California, but was moved to Eastman Chemical Company's coal gasification facility in Kingsport, Tennessee. The Eastman Chemical site offers the advantage of the use of existing coal gasifiers with little modification. The unit will produce at least 200 tons of methanol per day at the Kingsport location.

Project Cost: $213.7 million; $92 million provided by U.S. Department of Energy

LUBECK IGCC DEMONSTRATION PLANT - PreussenElektia (C-339)

The project of PreussenElektra/Germany has a capacity of 320 MWe net based on hard coal and a net efficiency of 45 percent. PRENFLO gasification technology has been chosen for the gasifier.

LU NAN AMMONIA-FROM-COAL PROJECT - China National Technical Import Corporation (C-360)

The China National Technical Import Corporation awarded a contract to Bechtel for consulting services on a commercial coal gasification project in the People's Republic of China. Bechtel will provide assistance in process design, design engineering, detailed engineering, procurement, construction, startup, and operator training for the installation of a 375 tons per day Texaco gasifier at the 200 metric tons per day Lu Nan Ammonia Complex in Tengqian, Shandong Province. The gasifier was completed in 1991, and has replaced an obsolete coal gasification facility with the more efficient Texaco process.

Project Cost: Not Disclosed

MILD GASIFICATION PROCESS DEMONSTRATION UNIT - Coal Technology Corporation and United States Department of Energy (DOE) (C-370)

Since the mid-1980s, Coal Technology Corporation (CTC), formerly UCC Research Corporation, has been investigating the pyrolysis of coal under sponsorship of DOE's Morgantown Energy Technology Center. This work initially was the development of a batch process demonstration unit having a coal feed capacity of 120 pounds per batch. The process produced coal liquids to be used for motor fuels and char to be potentially used for blast furnace coke and offgas.

In January 1988, DOE and CTC cost shared a $3,300,000 three-year program to develop a process demonstration unit for the pyrolysis of 1,000 pounds/hour of coal by a continuous process. This work involved a literature search to seek the best possible process; and then after small scale work, a proprietary process was designed and constructed. The unit began operating in February 1991. Test runs have been made with a variety of 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. Lumps of char discharged from the reactor is cooled in a water jacketed auger to 300°F. At present, the char is stored, but in an integrated facility, the cooled char would then be crushed, mixed with binder material and briquetted in preparation for conversion to coke in a continuous rotary hearth coker. The moisture and volatile hydrocarbons produced in the reactor are recovered and separated in scrubber/condensers into noncondensibles gases and liquids.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

The coal liquid, char, and coke (CTC/CLC) mild gasification technology to be demonstrated involves the production of three products from bituminous caking type coals: coal liquids for further refining into transportation fuels, char for ferro-alloy production, and formed coke for foundry and blast furnace application in the steel industry. The CTC/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 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 "green" briquettes. The green briquettes will directly feed into the specially designed rotary hearth continuous coking process for final calcining at 2,000°F to produce blast furnace formed coke. The small amount of uncondensed gases will be recirculated back through the system to provide a balanced heat source for the mild gasification retorts and the rotary hearth coking process. A total of 500 tons of coal per day will be used in the demonstration phase of this plant.

A feasibility study for construction and operation of a commercial plant has been completed and CTC is investigating options for financing the construction of 500 ton per day 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.

Pre-feasibility 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 (C→C) 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 C1'C 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 suggest 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. Over 50 tonnes of coal was successfully gasified during 21 performance tests with a cumulative feeding time of 18 days. Continuous operation for periods of up to 67 hours was achieved.

A full-scale physical model of a 50 tonne per day development-scale Coal Hydrogertator was commissioned in 1992. This has enabled the scaleup of the hydrogenator to be studied. A range of coal injectors at feedrates of up to 50 tonnes per day have been successfully tested.

The next stage of development is expected to be at 50 tonnes per day and consideration is being given for this to be built in Japan.

M.W. KELLOGG UPGRADING OF REFINERY OIL AND PETROLEUM COKE PROJECT – M.W. Kellogg Company and United States Department of Energy (C-404)

The Department of Energy (DOE) has selected the M.W. Kellogg Company, Houston, TX, to study a technology that could increase the efficiency of U.S. refineries by converting the heavy, difficult-to-process “bottom of the barrel” into commercially useful products.

As part of the $1.4 million, 3-year project, Kellogg will adapt a process originally developed for gasifying coal. The company will apply the technology to processing heavy slurry oil and the solid, coal-like petroleum coke often left after refineries extract lighter fuels such as gasoline, diesel and heating oil.

Kellogg has been working with the Energy Department since the early 1980s to develop the “pressurized ash agglomeration gasification system,” an advanced technique for gasifying coal. Engineers at the Kellogg Technology Development Center in Houston, will modify the process to substitute the heavy, unconverted refinery by products for coal.
COMMERCIAL AND R&D PROJECTS (Continued)

A bench-scale reactor unit, originally built for DOE co-sponsored coal gasification tests at a Kellogg subsidiary's pilot plant at Waltz Mill, PA, has been relocated, modified and rebuilt at the Houston center. It will be used to measure the quantity of useable gaseous products obtained when the reactions occur in a "bubbling fluidized bed"—a process in which the coke particles are swept through the gasification/combustion process at faster velocities than a bubbling fluidized bed.

A companion unit, called a transport reactor test unit, will be used to obtain similar data for reactions in which the particles are suspended on upward blowing jets of oxygen and steam.

A key aspect of the test program will be to track the fate of potential pollutants and determine ways to minimize air emissions. Petroleum coke often contains most of the impurities left behind by refinery processes. Unless a combustion plant is equipped with proper environmental controls—a rarity in many of the countries buying petroleum coke from the U.S.—burning petroleum coke can release sulfur pollutants. The solid wastes also contain such metals as nickel and vanadium.

The Kellogg approach could substantially minimize the release of air pollutants and reduce the amount of solid waste that must be disposed of. Several conventional and advanced processes have been developed for cleaning sulfur emissions from both gasification and combustion systems. Also, because the processes substantially reduce the quantity of solid waste, metal impurities are more concentrated in the ash and more easily handled and disposed of. For example, the ash potentially could be sold to smelters to recover the metals.

NEDO IGCC DEMONSTRATION PROJECT — New Energy and Industrial Technology Development Organization (NEDO) (C-408)

NEDO is studying integrated gasification combined cycle technology as part of a national energy program called the Sunshine Project. A 200 ton per day pilot plant has been constructed at the Nakoso power station site in Iwaki City, Fukushima Prefecture. The pilot began operating in March 1991.

The plant, which is designed to produce 42,900 cubic meters of synthetic gas per hour, is expected to operate for about 3 years using four different kinds of coal. The gasifier is an air blown, two stage entrained flow type with a dry-feeding system.

NEDO's goal is to develop a 250 megawatt demonstration plant by the year 2000 that has a net thermal efficiency greater than 43 percent and better operability than existing pulverized coal-fired plants. In order to obtain this goal, the development of the entrained flow gasification pilot plant will be followed by a fluidized bed gasification pilot plant.

NEDOL BITUMINOUS COAL LIQUEFACTION PROCESS — New Energy Development Organization (NEDO) (C-410)

Basic research on coal liquefaction was started in Japan when the Sunshine project was inaugurated in 1974, just after the first oil crisis in 1973. NEDO assumed the responsibility for development and commercialization of coal liquefaction and gasification technology. NEDO plans a continuing high level of investment for coal liquefaction R&D, involving two large pilot plants. The construction of a 50 tons per day brown coal liquefaction plant was completed in December 1986 in Australia, and a 150 tons per day bituminous coal liquefaction plant is planned in Japan.

The pilot plant in Australia is described in the project entitled "Victoria Brown Coal Liquefaction Project." The properties of brown coal and bituminous coal are so different that different processes must be developed for each to achieve optimal utilization. Therefore, NEDO has also been developing a process to liquefy sub-bituminous and low grade bituminous coals. NEDO had been operating three process development units (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 hydro-treated 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, five different coals were processed in the bench scale unit with encouraging results.

Project Cost: 100 billion yen, not including the three existing PDU

OSTRAVA DISTRICT HEATING PLANT — ABB Carbon (C-430)

A new district heating plant, using ABB Carbon's PFBC system, is planned for Ostrava, Czechoslovakia. The plant will burn high-ash bituminous coal with up to 1.2 percent sulfur. Efficiency is predicted to be about 80 percent and output is planned to be 52.7 MW in the winter and 62.5 MW in the summer. Compared to the existing cogeneration plant, sulfur emissions should drop by 90 percent, NO by 75 percent and particulates by 99.5 percent. The new power plant will be commissioned in 1996.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

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.

PINNION PINE IGCC POWERPLANT – Sierra Pacific Power Company, M.W. Kellogg Company (C-458)

Sierra Pacific Power Company is planning to build an 80 MW integrated gasification combined cycle plant at its Tracy Powerplant site, east of Reno, Nevada. The plant will incorporate an air-blown KRW fluidized bed gasifier producing a low-BTU gas for the combined cycle powerplant.

Dried and crushed coal is introduced into a pressurized, air-blown, fluidized-bed gasifier through a lockhopper system. The bed is fluidized by the injection of air and steam through special nozzles into the combustion zone. Crushed limestone is added to the gasifier to capture a portion of the sulfur introduced with the coal as well as to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits along with the coal ash in the form of agglomerated particles suitable for landfill.

Hot, low-BTU coal gas leaving the gasifier passes through cyclones which return most of the entrained particulate matter to the gasifier. The gas, which leaves the gasifier at about 1,700°F, is cooled to 1,050°F before entering the hot gas cleanup system. During cleanup, virtually all of the remaining particulates are removed by ceramic candle filters, and final traces of sulfur are removed in a fixed bed of zinc ferrite sorbent.

In the demonstration project, a nominal 800 tons per day of coal is converted into 86 megawatts; support facilities for the plant require 6 megawatts, leaving 80 megawatts for export to the grid. The plant has a calculated heat rate of 9,082 BTU per kilowatt-hour (HHV). The project will be designed to run on Western subbituminous coal from Utah; operation with higher sulfur and lower rank coals also is being considered.

The U.S. Department of Energy (DOE) has agreed to fund half of the $270 million project cost. The project is funded by DOE through the Clean Coal Technology Program, Round 4. Sierra Pacific Power will fund the remaining 50 percent.

Foster Wheeler USA Corp. has been contracted to provide design, engineering, construction, manufacturing and environmental services for the project.

The permitting process was initiated in 1992. Completion is estimated for 1996-1997. The Public Service Commission of Nevada approved the project on October 25, 1993. A draft EIS is being prepared by DOE.

Project Cost: $270 million for four year operating demonstration project

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.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

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 live 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.

PREFNFO 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 Kohletechnologie) are presently operating a 48 ton per day demonstration plant and designing a 2,400 ton per day module for the PREFNFO process. The PREFNFO process is KK's pressurized version of the Koppers-Totzek (KT) flow gasifier. Detailed engineering has been completed for a 1,200 ton per day module.

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 PREFNFO 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 was located at Fuerstenhausen, West Germany. In over 10,000 hours of test operation 12 different fuels with ash contents of up to 40 percent were successfully used. All fuels used are converted to more than 96 percent, and in the case of fly ash recycled to more than 99 percent.

Project Cost: Not disclosed

PRESSURIZED FLUID BED COMBUSTION ADVANCED CONCEPTS – M. W. Kellogg Company (C-473)

In September of 1988, Kellogg was awarded a contract by the DOE to study the application of transport mode gasification and combustion of coal in an Advanced Hybrid power cycle. The study was completed in 1990 and demonstrated that the cycle can reduce the cost of electricity by 20-30 percent (compared to a PC/FGD system) and raise plant efficiency to 45 percent or more.

The Hybrid system combines the advantages of a pressurized coal gasifier and a pressurized combustor which are used to drive a high efficiency gas turbine generator to produce electricity. The proprietary Kellogg system processes pulverized coal and limestone and relies on high velocity transport reactors to achieve high conversion and low emissions.

DOE, in late 1990, awarded a contract to Southern Company Services, Inc. for addition of a Hot Gas Cleanup Test Facility to their Wilsonville test facility. The new unit will test particulate removal devices for advanced combined cycle systems and Kellogg's Transport gasifier and combustor technology will be used to produce the fuel gas and flue gas for the testing program. The reactor system is expected to process up to 48 tons per day of coal. [See Hot Gas Cleanup Process (C-257)].

Kellogg has built a bench scale test unit to verify the kinetic data for the transport reactor system and has completed testing in both gasification and combustion modes, using bituminous and subbituminous coals. The results in both modes have verified the concept that reactors designed to process pulverized coal and limestone can achieve commercial conversion levels while operating at high velocities and short contact times. The test data have been used to support the design of the Wilsonville test gas generator, and another unit at UND/EERC.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

The gasifier converts part of the coal to a low-BTU gas that is filtered and sent to the gas turbine. The remaining char is combusted and the flue gas is filtered and also goes to the gas turbine. The advantages of the system in addition to high efficiency are lower capital cost and greatly reduced SO_{x} and NO_{x} emissions.

DOE has also approved the design, fabrication, installation and operation of a Process Development Unit (PDU) based upon Kellogg's Transport gasification process at the University of North Dakota, Energy and Environmental Research Center (UND/EERC). The unit will process 2.4 tons per day of pulverized bituminous coal. Startup of this unit is scheduled for September 1993.

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, conducted at Kellogg's Houston Technology Development Center, investigates 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.

PUERTOLLANO IGCC DEMONSTRATION PLANT — ELCOGAS, S.A. (C-476)

Under the corporation ELCOGAS S.A., the Spanish utility company ENDESA together with EDF/France, IBERDROLA/Spain, Hidroeléctrica del Cantábrico/Spain, SEVILLANA/Spain, ENEL/Italy, and EDP/Portugal are involved in the Puertollano project. The project also has the European Economic Commission support, under the Thermie Program.

The proposed project has a capacity of approximately 305 MWe, which is influenced by the type of gas turbine selected (Siemens or Alsthom). The PRENFLO gasification technology has been chosen for the gasifier.

The plant configuration is single-train throughout. Using oxygen and steam, about 100 tons of coal per hour will be gasified. The required oxygen, approximately 90 tons per hour, will be produced in a single-train air separation unit. The resulting coal gas will be dedusted, desulfurized and saturated in a single-train configuration and then combusted in a single combustion turbine.

A 50/50 mixture of Puertollano coal and petroleum coke from the Puertollano Petroleum Refinery is intended to be the main feedstock for this project. Coals from England, Spain, France, the United States, China, Austria, Columbia, Germany, Poland and South Africa will also be tested over the 3-year demonstration period.

SO_{x} Emission values of 10 mg/m^{3} and NO_{x} values of 60 mg/m^{3} are expected in the exhaust gas (based on 15 volume percent oxygen).

The combined cycle power plant at Puertollano will be switched into the grid in the second quarter of 1996, fueled initially with natural gas. Conversion to coal gas will take place by the end of 1996. A 3-year demonstration period is planned.

Project Cost: ECU600 million

PYGAS DEMONSTRATION PROJECT — Morgantown Energy Technology Center (METC), CRS Sirrine Engineers, Inc. (C-477)

METC and CRS Sirrine have been working on the development of a gasifier which uses carbonizer tubes as a means to drive off coal volatiles and tar prior to the conventional fixed-bed gasifier process. The combination of carbonizer (pyrolysis) tube and fixed-bed gasifier results in coal "Pyrolysis" and "Gasification," hence the name PyGas.

A gasification facility will be built at METC's Gasification Product Improvement Facility (GPIF) located at Monongahela Power's Fort Martin site. The gasifier will be rated at 6 tons per hour coal throughput. Operating pressure is 600 psi. It is expected to be 5 feet in diameter and 34 feet high.

The concept of the facility is to meter feed coal alone or with limestone through a crusher/dryer and pressure lock pneumatically to the pyrolyzer section of the gasifier. Porous devolatilized char and pyrolysis gas exit the top of the pyrolyzer. Air is injected into the upper dome of the gasifier to raise the temperature high enough to crack tar vapors in the pyrolysis gas. The char separates from the gas by gravity and forms the fixed bed.

The gases pass countercurrently downward with the char into the conventional fixed-bed gasification section. The porous char is further gasified by the countercurrent admittance of air or steam and steam through a rotating grate.

QINGDAO GASIFICATION PLANT (C-478)

China is building a coal gasification plant in the northern city of Qingdao in the Shandong province. The plant, which will produce 26.5 million cf per day of gas, involves two coke-making batteries, a coal preparation plant, a thermal power station and 14 gas retorts. The plant will provide a district heating network for the 6.7 million person city, eliminating hundreds of coal-fired boilers and stoves.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

The gasification project is part of a $210 million environmental cleanup program in Qingdao. The Asian Development Bank will finance $103 million of the total cost, with China providing the balance.

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 Eisenhuttenkunde* 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 tons of dried brown coal were processed in about 36,000 hours of operation. The specific synthesis gas yield reached 1,580 standard cubic meters per ton of brown coal (MAP) corresponding to 96 percent of the thermodynamically calculated value. At feed rates of about 1,800 kilograms per hour coal, the synthesis gas output of more than 7,700 standard cubic meters per hour per square meter of gasifier area was more than threefold the values of atmospheric Winkler gasifiers.

After gasification tests with Finnish peat in the HTW pilot plant in the spring of 1984 the Kemira Oy Company of Finland decided to convert an existing ammonia production plant at Oulu from heavy oil to peat gasification according to the HTW process. The plant was designed to gasify approximately 650 tons per day of peat at 10 bar and process it to 280 tons per day of ammonia. This plant started up in 1988.

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. From startup in January 1986 until the end of December 1993 about 1,073,624 tons of dried brown coal, especially high ash containing steam coal, were processed in about 47,700 hours of operation. During this time, about 1,431 million cubic meters of synthesis gas were produced.

A new pilot plant, called pressurized HTW gasification plant, for pressures up to 25 bar and throughputs up to 6.5 tons 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 January 1992 the plant was operated for 6,753 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 air blown and 79 percent cold-gas efficiency and 105 MW, specific fuel gas flow per square meter oxygen blown.

From February to September 1992 tests with a German hard coal and with Pittsburgh No. 8 coal were successfully performed in the pressurized HTW gasification plant using oxygen and air as gasification agents as well. Within 543 hours of operation 728 tons of hard coal was processed.

This work is performed in close co-ordination with Rheinbraun's parent company, the Rheinisich-Westfälisches Elektrizitätswerk (RWE), which operates power stations of a capacity of some 9,300 megawatts on the basis of lignite. Since this generating capacity will have to be renewed after the turn of the century, it is intended to develop the IGCC technology so as to have a process available for the new powerplants. 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 online in 1996 and will have a capacity of 300 MW of electric power. The gas will be produced in one air-blown gasifier. See KOBRA HTW-IGCC Project (C-294).

Project Cost: Not disclosed

SYNTHETIC FUELS REPORT, MARCH 1994

4-82
Sasol Limited is the holding company of the multi divisional Sasol Group of Companies. Sasol is a world leader in the commercial production of coal based synthetic fuels. The Synthol oil-from-coal process was developed by Sasol in South Africa in the course of more than 30 years. A unique process in the field, its commercial-scale viability has been fully proven and its economic viability conclusively demonstrated.

The first Sasol plant was established in Sasolburg in the early fifties. The much larger Sasol Two and Three plants, at Secunda—situated on the Eastern Highveld of Transvaal, came on-stream in 1980 and 1982, respectively.

The two Secunda plants are virtually identical and both are much larger than Sasol One, which served as their prototype. Enormous quantities of feedstock are produced at these plants. At full production, their daily consumption of coal is almost 100,000 tons, of oxygen, 28,000 tons; and of water, 250 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 coal gasifiers, oxygen plants, Rectisol gas purification units, synthol reactors, gas reformers and refineries. Hydrocarbon synthesis takes place by means of the Sasol licensed 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 Polymer 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 octane 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 three Secunda Collieries (including the new open cast mines, Syferfontein and Wonderwater), 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 $3.5 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 55,000 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 120,000 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, Sasol One, to manufacture paraffinic products for detergents was commissioned in March 1993.

An n-butanol plant to recover acetaldehyde from the Secunda facilities and to produce 17,500 tons per year of n-butanol was commissioned during 1992.

Sasol will construct a delayed coker facility 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 July 1993.

A flexible plant to recover 100,000 tons per year of 1-hexane or 1-pentone will be built to come online in January 1994. The technology was developed in-house by Sasol.

A krypton/xenon gas recovery plant adjacent to Secunda oxygen units was commissioned in 1993.
COMMERCIAL AND R&D PROJECTS (Continued)

A major renewal project at Sasol One includes the replacement of the fixed bed Fischer-Tropsch plant with the new Sasol Slurry Bed Reactor. The renewal also includes shutting down much of the synthetic fuels capability at this plant.

Project Cost: 
- SASOL Two $2.9 Billion
- SASOL Three $3.8 Billion

*At exchange rates ruling at construction

SCOTIA COAL SYNFUELS PROJECT – DEVCO; Alastair Gillespie & Associates Limited; Gulf Canada Products Company; NOVA; Nova Scotia Resources Limited; and Petro-Canada (C-500)

The consortium conducted a feasibility study of a coal liquefaction plant in Cape Breton, Nova Scotia using local coal to produce gasoline and diesel fuel. The plant would be built either in the area of the Point Tupper Refinery or near the coal mines. The 25,000 barrels per day production goal would require approximately 2.5 million tonnes of coal per year. A contract was completed with Chevron Research Inc. to test the coals in their two-stage direct liquefaction process (CCLP). A feasibility report was completed and feasibility options discussed with governments concerned and other parties.

Scotia Synfuels Limited has been incorporated to carry on the work of the consortium. Scotia Synfuels has down-sized the project to 12,500 barrels per day based on a coprocessing concept and purchased the Point Tupper site from Ultramar Canada Inc. Recent developments in coprocessing 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 $25 million coprocessing feasibility study. The study was completed in 1990.

Based on the test program results, material and energy balances were developed for a commercial facility. An economic model was developed to analyze a number of options. The model incorporated government investment support programs available in eastern Canada. The primary incentives were investment tax credits and loan financing.

Discussions on project financing continued in 1991 with the governments of Canada and Nova Scotia and private corporations.

Project Cost: 
- Approximately $2.5 million for the feasibility study
- Approximately C$500 million for the plant

SEP IGCC POWERPLANT – Demkolec B.V. (SEP) (C-520)

In 1989, Demkolec, a wholly owned subsidiary of Samenwerkende Elektriciteits-Productiebedrijven (SEP), the Central Dutch electricity generating board, started to build a 253 megawatt integrated coal gasification combined cycle (IGCC) powerplant, 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 coal gasification/combined cycle demonstration station is Buggenum, in the province of Limburg, The Netherlands.

The coal gasification facility will employ a single 2,000 ton per day gasifier designed on the basis of Shell technology. The clean gas will fuel a single shaft Siemens V94.2 gas turbine (156 MWe) coupled with steam turbine (128 MWe) and generator. The coal gasification plant will be fully integrated with the combined cycle plant, including the boiler feed water and steam systems; additionally the compressed air for the air separation plant will be provided as a bleed stream from the compressor of the gas turbine. The design heat rate on internationally traded Australian coal (Drayton) is 8,240 BTU/kWh based on coal higher heating value (HHV).

Environmental permits based on NO₂ emissions of 0.17 lb/MMBTU and SO₂ emissions of 0.06 lb/MMBTU were obtained in April 1990. Construction began in July 1990 and start of operation is scheduled for September 1993. When operation begins, the Demkolec plant will be the largest coal gasification combined cycle powerplant in the world. Commissioning of the main plant system is scheduled to take place in January through July 1993.

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)
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

SHANGHAI CHEMICALS FROM COAL PLANT — People’s Republic of China (C-525)

The Chinese government has approved construction of a new methanol complex. Using coal as raw material, the Shanghai-based plant is expected to produce 100,000 tons per year of methanol and 15,000 tons per year of acetate fiber. Completion is due in 1992.

SHOUGANG COAL GASIFICATION PROJECT — People’s Republic of China (C-527)

The Shougang plant will gasify 1,170 tons per day of Chinese anthracite using the Texaco coal gasification process. The gasification plant will produce fuel gas for an existing steel mill and town gas. The detailed design is being completed and equipment fabrication is underway. The plant is expected to be operational in late 1992.

SLAGGING GASIFIER PROJECT — British Gas Corporation (C-540)

The British Gas Corporation (BGC) constructed a prototype high pressure slagging fixed bed gasifier in 1974 at Westfield, Scotland. (This gasifier has a 6 foot diameter and a throughput of 300 tons per day.) The plant successfully operated on a wide range of British and American coals, including strongly caking and highly swelling coals. The ability to use a considerable proportion of fine coal in the feed to the top of the gasifier has been demonstrated as well as the injection of further quantities of fine coal through the tuyeres into the base of the gasifier. Byproduct hydrocarbon oils and tars can be recycled and gasified to extinction. The coal is gasified in steam and oxygen. The slag produced is removed from the gasifier in the form of granular frit. Gasification is substantially complete with a high thermal efficiency. A long term proving run on the gasifier was carried out successfully between 1975 and 1983. Total operating time was over one year and over 100,000 tons of coal were gasified.

A second phase, started in November 1984, was 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 were 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 had gasified over 26,000 tons of British and American (Pittsburgh No. 8 and Illinois No. 6) coals.

The 500-ton per day gasifier was operated at 25 bar until the end of 1990.

An experimental gasifier designed to operate in the fixed bed slagger mode at pressure up to 70 atmospheres was constructed in 1988. It was designed for a throughput of 200 tons per day. This unit was operated through 1991. Operation of the gasifier was excellent over the entire pressure range; the slag was discharged automatically, and the product gas was of a consistent quality. At corresponding pressures and loadings the performance of the 200-ton per day gasifier was similar to that of the 500-ton per day unit previously used.

As the pressure rises, the gas composition shows a progressive increase in methane and a decrease in hydrogen and ethylene, while the ethane remains fairly constant. The tar yield as a percentage of the dry ash free coal decreases with pressure. The cold gas efficiency, i.e., the proportion of the fuel input converted to potential heat in the output gas, was above 90 percent. The throughput increased approximately with the square root of the ratio of the operating pressures.

Project Cost: Not available

SYNTHESISANLAGENRUHR (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 Synthesegasanlage 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 oxosynthesis plants. The gasification plant has been modified to allow for input of either hard coal or heavy oil residues. The initial investment was subsidized by the Federal Minister of Economics of the Federal Republic of Germany. The Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia participates in the coal costs.

Project Costs: DM220 million (Investment)
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

TAMPELLA IGCC PROCESS DEMONSTRATION - Tampella Power (C-565)

After having obtained the rights to the Institute of Gas Technology's fluidized bed gasification technology in 1989, Tampella Keeler began to design and initiate construction of a 10 MW thermal pilot plant at their research facilities in Tampere, Finland. The pilot plant is considered essential for determining operating parameters for specific coals and for continuing process development in the areas of in-gasifier sulfur capture and hot gas cleanup. The pilot plant will be operational in early 1991.

The pilot plant is designed so that alternative hot gas filters and zinc ferrite absorber/regenerator design concepts can be evaluated. The gasifier is 66 foot tall, with an inside diameter ranging from 2 to 4 feet. The gasifier will be capable of operating at pressures up to 425 psig.

After the pilot plant construction was underway, Tampella turned its attention towards locating a demonstration project in Finland and one in the U.S. A cogeneration project to be located at an existing 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.

In September, 1991 Tampella received support from the U.S. Department of Energy (DOE) to build an integrated gasification combined-cycle demonstration facility, known as the Toms Creek IGCC Demonstration Project, in Coeburn, Wise County, Virginia (see project C-580, below). The Toms Creek Project will utilize Tampella Power's advanced coal gasification technology to demonstrate improved efficiency for conversion of coal to electric power while significantly reducing SO$_2$ and NO$_x$ emissions.

TECO IGCC PLANT - Teco Power Services, U.S. Department of Energy (C-567)

Tampa Electric Company (TEC) is starting detailed engineering for its new Polk Power Station Unit #1. This will be the first unit at a new site and will use Integrated Gasification Combined Cycle (IGCC) Technology. The project is partially funded by the U.S. Department of Energy (DOE) under Round III of its Clean Coal Technology Program. In addition to the TEC and DOE, TECO Power Services (TPS), a subsidiary of TECO Energy, Inc., and an affiliate of TEC, is also participating in the project. TPS is responsible for the overall project management for the DOE portion of this IGCC project.

The Polk Power Station IGCC Project will be constructed in two phases. TEC's operation needs called for 150 MW of peaking capacity in mid-1995, becoming part of the 260 MW of total IGCC capacity in mid-1996. The first phase will be the installation of an advanced combustion turbine (CT) scheduled for commercial operation in July 1995. This CT will fire No. 2 oil during its first year while in peaking service. During that year, TEC will complete installation of the gasification and combined cycle facilities which will be in commercial operation in July 1996.

In addition, part of this DOE CCT project will be to test and demonstrate a new hot gas clean-up (HGCU) technology.

The Texaco Gasification Process has been selected for integration with a combined cycle power block.

Part of the Cooperative Agreement for this project is the two-year demonstration phase. During this period it is planned that about four to six different types of coal will be tested in the operating IGCC power plant. The results of these tests will compare this unit's efficiency, operability, and costs, and report on each of these test coals specified against the design basis coal. These results should identify operating parameters and costs which can be used by utilities in the future as they make their selection on methods for meeting both their generation needs and environmental regulations.

Project Cost: $241.5 million

TEXACO COOL WATER PROJECT - Texaco Syngas Inc. (C-569)

Original Cool Water participants built a 1,000-1,200 tons per day commercial-scale coal gasification plant using the oxygen-blown Texaco Coal Gasification Process. The gasification system which includes two Syngas Cooler vessels, was integrated with a General Electric combined cycle unit to produce approximately 122 megawatts of gross power. Plant construction, which began in December 1981, was completed on April 30, 1984, within the projected $300 million budget. A 5-year demonstration period was completed in January 1989. See "Cool Water Project" in the December 1991 issue of the Synthetic Fuels Report, Status of Projects section for details of the original completed project.

Texaco plans to modify and reactivate the existing facilities to demonstrate new activities which include the addition of sewage sludge into the coal feedstock, production of methanol, and carbon dioxide recovery.

Texaco intends to use a new application of Texaco's technology which will allow the Cool Water plant to convert municipal sewage sludge to useful energy by mixing it with the coal feedstock. Texaco has demonstrated in pilot runs that sludge can be mixed with coal and, under high temperatures and pressures, gasified to produce a clean synthesis gas. The plant will produce no harmful byproducts.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

Texaco Syngas Inc. has initiated efforts to restructure the financing of the Texaco Cool Water Project and continues to negotiate with Southern California Edison Company for the power purchase agreement based on the California Energy Commission Committee Order dated November 2, 1992. Successful negotiation of the power purchase agreement, with necessary State of California approvals, would allow the acquisition of the Cool Water Gasification Facility, by Texaco Syngas Inc. from Southern California Edison Company, to be completed.

Project Cost: $263 million for original Cool Water Coal Gasification Program
$213.7 million for the commercial demonstration of the liquid-phase methanol process

TEXACO MONTEBELLO RESEARCH LABORATORY STUDIES – Texaco Inc. (C-571)

Texaco has a number of on-going coal gasification research and development programs at its Montebello Research Laboratory (MRL). MRL is a major pilot-scale process development facility which has been involved in gasification research since 1946. It currently has three gasifiers with rated capacities of 15-30 tons per day of coal. These units are also capable of feeding a wide range of other solid and liquid fuels.

MRL serves the dual purpose of doing research and pilot unit testing for the development of the Texaco Gasification Process (TGP), and obtaining data required for the design and environmental permitting of commercial plants. In recent years, the research emphasis has expanded to include the improved integration of the gasification process with the overall chemical or powerplant. This has involved the development of high temperature syngas cleanup technology (jointly funded by the U.S. Department of Energy), improved low temperature acid gas removal processes and engineering studies aimed at increasing the efficiency and reducing the cost of Texaco gasification based chemical and power generation plants.

In addition, the research also continues to expand the already wide range of feeds which can be gasified by the TGP. Recent work has included oily wastes, Orimulsion, contaminated soil, sewage sludge, plastics and tire oil, made by the liquefaction of used tires in waste oils, such as used motor oil.


ThermoChem will demonstrate Manufacturing and Technology Conversion International's (MTCI) pulse combustor in an application for steam gasification of coal. This gasification process will produce a medium BTU content fuel gas from subbituminous coal at a mine-mouth K-Fuel production plant in Gillette, Wyoming. The fuel gas and byproduct steam produced by this demonstration unit will be used in the K-Fuel Process.

The heat required for the gasification will be supplied by the combustion of cleaned gasification products (fuel gas) in numerous pulsed combustion tubes. The products of pulsed combustion are separated from the gasification products. Since no dilution of the byproducts of combustion or of gasified fuel gas occurs, a medium BTU content fuel (500 BTU/scf) gas will be produced. The turbulent nature of the pulsed combustor contributes to a high combustion heat release density and high heat transfer rates to the gasifier bed. The fluidized bed coal gasifier also offers high turbulence and heat transfer rates.

The objective of the ThermoChem project is the demonstration of a 300 ton per day (as-received coal) novel coal gasification unit. It will supply a product fuel gas with a heating value of 161.2 million BTU/hr for boiler fuel. Use of the fuel gas in place of hog-fuel boilers will lower particulate emissions at the host facility. Another goal of the project is to determine whether gasification can be used on other potential energy sources, such as pulp-making byproducts.

A preliminary design of the ThermoChem coal gasification demonstration plant integrated with the host K-Fuel facility was completed in April 1993. Test gasification of the designed coal is under way at ThermoChem's Baltimore, Maryland facility.

The U.S. Department of Energy will fund 50 percent of the project under Round 4 of the Clean Coal Technology Program.

Project Cost: $37.3 million for four years

TOM'S CREEK IGCC DEMONSTRATION PLANT – TAMCO Power Partners and U.S. Department of Energy (C-580)

TAMCO Power Partners, a partnership between Tampella Power Corporation and Coastal Power Production Company will build an integrated gasification combined cycle powerplant in Coeburn, Virginia. The U.S. Department of Energy will fund 48.3 percent of the $197 million project under Round 4 of its Clean Coal Technology Program.

The project will demonstrate a single air blown fluidized bed gasifier, based on the U-GAS technology developed by the Institute of Gas Technology. The plant will burn 430 tons per day of local bituminous coal and produce a net 53 MWe. Power will be generated by firing low-BTU product gas in a gas turbine generator and by a steam turbine generator supplied by the waste heat from the gas turbine.

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COMMERCIAL AND R&D PROJECTS (Continued)

A cooperative agreement was signed with the DOE in October 1992. A power sales agreement has yet to be signed.

Project Cost: $196.6 million

UBE AMMONIA-FROM-COAL PLANT -- Ube Industries, Ltd. (C-590)

Ube Industries, Ltd., of Tokyo completed the world's first large scale ammonia plant based on the Texaco coal gasification process (TCGP) in 1984. There are four complete trains of quench mode gasifiers in the plant. In normal operation three trains are used with one for stand-by. Ube began with a comparative study of available coal gasification processes in 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, naphthas and LPG as required.

Project Cost - Not disclosed

VARTAN DISTRICT HEATING PLANT -- Energie Verk (C-595)

In 1990, a gas turbine PFBC system went into operation at the Vartan district heating plant in Stockholm, Sweden. The gas turbine is a two-shaft, intercooled machine with the compressor providing the combustion air for the fluidized bed, which is then returned through a cyclone system to clean the gas before it enters the turbine. In a combined cycle the gas turbine exhaust heat is captured in the usual way, but the heat recovery boiler acts only as an evaporator, because the superheater stage is formed by a tube bundle embedded in the fluidized bed.

The Vartan plant has an output of 135 MW of electric capacity and 210 MW thermal (MWt). The coal used has about 1 percent sulfur and is fed to the combustor as a coal-water paste. Efficiency is about 42 percent.

Project Cost - Not disclosed

VEW GASIFICATION PROCESS -- Vereinigte Elektrizitatswerke Westfalen AG, Dortmund (C-600)

A gasification process being specially developed for application in powerplants is the VEW Coal Conversion Process of Vereinigte Elektrizitatswerke 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 powerplant 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. NOx reduction and sulfur removal is carried out in the combustor.

Project Cost: Not disclosed
COMMERCIAL AND R&D PROJECTS (Continued)

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, slurring, and primary hydrogenation sections comprising the first phase of the project began in November 1981. The remaining sections, consisting of solvent deashing and secondary hydrogenation, were completed during 1986. The pilot plant was operated until October 1990, and shut down at that point.

The pilot plant is located adjacent to the Morwell open cut brown coal mine. Davy McKee Pacific Pty. Ltd., provided the Australian portion of engineering design procurement and construction management of the pilot plant. The aim of the pilot plant was to prove the effectiveness of the BCL Process which had been developed since 1971 by the consortium.

Work at the BCLV plant was moved in 1990 to a Japanese laboratory, starting a three-year study that will determine whether a demonstration plant should be built. NBCL is developing a small laboratory in Kobe, Japan, specifically to study the Morwell project.

Part of the plant will be demolished and the Coal Corporation of Victoria is considering using a part of the plant for an R&D program aimed at developing more efficient brown coal technologies. The possibility of building a demonstration unit capable of producing 16,000 barrels per day from 5,000 tonnes per day of dry coal will be examined in Japan.

If a commercial plant were to be constructed, it would be capable of producing 100,000 barrels of synthetic oil, consisting of six lines of plant capable of producing 16,000 barrels from 5,000 tonnes per day dry coal. For this future stage, Australian companies will be called for equity participation for the project.

Project Cost: Approximately $700 million

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT — Destec Energy, Inc. and PSI Energy Inc. (C-614)

Located in West Terre Haute, Indiana, the project will repower one of the six units at PSI Energy's Wabash River power station. The repowering scheme will use a single train, oxygen-blown Destec gasification plant and the existing steam turbine in a new integrated gasification combined cycle configuration to produce 262 megawatts of electricity from 2,553 tons per day of high sulfur Illinois basin bituminous coal. The plant will be designed to substantially out-perform the standards established in the Clean Air Act Amendments for the year 2000. The demonstration period for the project will be 3 years after plant startup.

The CGCC system will consist of Destec's two-stage, entrained-flow coal gasifier, a gas conditioning system for removing sulfur compounds and particulates; systems or mechanical devices for improved coal feed; a combined-cycle power generation system, wherein the conditioned synthetic fuel gas is combusted in a combustion turbine generator; a gas cleanup system; a heat recovery steam generator; all necessary coal handling equipment; and an existing plant steam turbine and associated equipment.

The demonstration will result in a combined-cycle powerplant with low emissions and high net plant efficiency. The net plant heat rate for the new, repowered unit will be 9,030 BTU per kilowatt-hour, representing a 20 percent improvement over the existing unit while cutting SO₂ by greater than 98 percent and NOₓ emissions by greater than 85 percent.

The project was selected for funding under Round IV of the U.S. Department of Energy's (DOE) Clean Coal Technology Program, and is slated to operate commercially following the demonstration period. DOE has agreed to provide funding of up to $198 million under the Cooperative Agreement.

Construction began in the summer of 1993 and will be completed, with startup, by third quarter 1995.

Project Cost: $396 million
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

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, evaluated 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 study was completed in mid 1991. During the course of the study, it was determined that the project would be too expensive and questions about the necessity of the use of IGCC technology to reduce CO emissions were also raised. However, two companies, Nova Scotia Power and Saskatchewan Power are still actively considering the results of the feasibility study to determine whether or not to go ahead with a siting study for the project.

As of August 1993, no IGCC plant is being actively planned.

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.

Construction of the ACCP demonstration facility is complete and initial "turnover" of equipment started in December 1991. The DOE agreement calls for a 3-year operation demonstrating the ability to produce a clean, high quality, upgraded product and testing the product in utility and industrial applications.

Plant construction was completed ahead of schedule and, following shakedown activities, startup was achieved in early 1992. When in continuous operation, the plant will produce 1,000 tons per day, or 300,000 tons per year of upgraded solid fuel at full production.

Rosebud Syncoal Partnership successfully worked with Montana Power Company’s Corette plant to conduct 7 months of tests using a Syncoal/raw coal blend.

Based on the successful demonstration, Western Energy hopes to build a privately financed commercial-scale plant processing 1 to 3 million tons of coal per year by 1997.

In late December 1993, Minnkota Power Cooperative signed a letter of intent with Rosebud SynCoal Partnership for a $2 million study to examine the merits of scaling up the latter's technology to an $80 million commercial plant.

The SynCoal plant would be sited next to Minnkota’s Milton R. Young power station near Center, North Dakota, northwest of Bismarck. The engineering and design study would be completed in mid-1994.

Project Cost: $69 million

WILSONVILLE POWER SYSTEMS DEVELOPMENT FACILITY (PSDF) PROJECT — Southern Company Services, Inc. and United States Department of Energy (C-617)

The PSDF will consist of five modules for systems and component testing. These modules include an Advanced Pressurized Fluidized Bed Combustion (APFBC) Module, and Advance Gasifier Module, Hot Gas Cleanup Module, Compressor/Turbine Module, and a Fuel Cell Module.

The intent of the PSDF is to provide a flexible test facility that can be used to develop advanced power system components, evaluate advanced turbine and fuel cell system configurations, and assess the integration and control issues of these advanced power systems. The facility would provide a resource for rigorous, long-term testing and performance assessment of hot stream cleanup devices in an integrated environment, permitting evaluation of not only the cleanup devices but also other components in an integrated operation.
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

The facility will be located at the Southern Company's Clean Coal Research Center in Wilsonville, AL. It will be sized to feed 104 tons per day of Illinois No. 6 bituminous coal with a Powder River subbituminous coal as an alternate coal. Longview Lime- stone, which is obtained locally near Wilsonville, has been chosen for initial testing.

The advanced gasifier module involves M.W. Kellogg's transport technology for pressurized combustion and gasification to provide either an oxidizing or reducing gas for parametric testing of hot particulate control devices. The transport reactor is sized to process nominally 2 tons per hour of coal to deliver 1,000 ACFM of particulate laden gas to the PCD inlet over the temperature range of 1,000 to 1,800°F at 300 psig.

The second-generation APFBC system is capable of achieving 45 percent net plant efficiency. The APFBC system designed for the PSDF consists of a high pressure (170 psia), medium temperature (1,600°F) carbonizer to generate 1,500 ACFM of low-BTU fuel gas and a circulating PFBC (operating at 150 psia, 1,600°F) generating 7,500 ACFM combustion gas. The coal feed rate to carbonizer will be 2.75 tons per hour, and with the Longview limestone, a Ca/S molar ratio of 1.75 is required to capture 90 percent of the sulfur in the carbonizer/PFBC. The gas exiting from the carbonizer and the CPFBC is filtered hot to remove particulates prior to the topping combustor.

A Multi-Annular Swirl Burner (MASB) is chosen to combust the gases from the carbonizer and increase the temperature of the CPFBC flue gases to 2,350°F. The exit gases are, however, cooled to 1,970°F in order to meet the temperature limitation on the gas turbine.

The hot gas is expanded through a gas turbine (Allison Model 501-KM), powering both the electric generator and air compressor.

The hot gases coming off the transport reactor, carbonizer and CPFBC will be cleaned by different PCDs. The PCDs from several different developers are being evaluated for testing at the PSDF. The list includes ceramic cross-flow, candle and tube filters and screenless granular bed filters.

Plans are being made to eventually integrate a fuel cell module with the transport gasifier. The capacity of the fuel cell to be tested initially is set at 100 kW. Provision has been made in the site layout of the PSDF to phase in a multi-MW fuel cell module with commercial stacks utilizing more than 80 percent of gases from the transport gasifier.

Installation is scheduled to be completed by the end of 1994, followed by operation of the facility from 1995 through 1997.

Project Cost: $147 million 80% by U.S. Department of Energy

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 1.7 million cubic meters per day of 3,800 Kcal per cubic meter of town gas; 60,000 kilowatt-hours of electricity per year; 100 metric tons per hour of low pressure steam; and 200,000 metric tons per year of 99.85 percent purity chemical grade methanol, 50,000 metric tons per year of acetic anhydride, and 50,000 metric tons per year of cellulose acetate. The project will be constructed in three phases.

In Phase 1, the production plan is further divided into 2 stages. In the first stage, 1 million cubic meters per day of town gas and 100,000 tons per year of methanol will be produced. The second stage will add another 0.7 million cubic meters per day of town gas and other 100,000 tons per year of methanol.

In November 1991, SCCP and Texaco Development Corporation signed an agreement for Texaco to furnish the gasifier, coal slurry and methanol systems. SCCP will import other advanced technologies and create foreign joint ventures at later stages for the production of acetic anhydride, formic acid, cellulose acetate and combined cycle power generation.

In March 1992, a foundation stone laying ceremony was performed at the plant site. In December of 1993, three sets of Air Separation units, each producing 11,000 cubic meters per hour of 99.6% oxygen, were started up. Phase 1 is scheduled to be completed by June 1995.

Project Cost: 2 billion yuan
STATUS OF COAL PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL AND R&D PROJECTS (Continued)

YUNNAN LURGI CHEMICAL FERTILIZERS PLANT - Yunnan Province, China (C-625)

In the 1970s, a chemical fertilizer plant was set up in Yunnan province by using Lurgi pressurized gasifiers of 2.7 meter diameter. The pressurized gasification of a coal water slurry has completed a model test with a coal throughput of 20 kilograms per hour and achieved success in a pilot unit of 1.5 tons per hour. The carbon conversion reached 95 percent, with a cold gas efficiency of 66 percent.

For water-gas generation, coke was first used as feedstock. In the 1950s, experiments of using anthracite to replace coke were successful, thus reducing the production cost of ammonia by 25 to 30 percent. In order to substitute coal briquettes for lump anthracite, the Beijing Research Institute of Coal Chemistry developed a coal briquetting process in which humate was used as a binder to produce synthetic gas for chemical fertilizer production. This process has been applied to production.

YUNNAN PROVINCE COAL GASIFICATION PLANT - People's Republic of China (C-630)

China is building a coal gasification plant in Kunming, Yunnan Province, that will produce about 220,000 cubic meters of coalgas per day. Joe Ng Engineering of Ontario, Canada has been contracted to design and equip the plant with the help of a $5 million loan from the Canadian Export Development Corporation.
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DOE CONTRACTORS REPORT PROGRESS IN NATURAL GAS CONVERSION

Work on the conversion of methane and other components of natural gas to various products was reported at a Fuels Technology Contractors Review Meeting, held at the United States Department of Energy Morgantown Energy Technology Center, Morgantown, West Virginia, in November.

Areas of research include:

- Conversion of natural gas components to heavier hydrocarbons using catalytic materials in packed-bed and membrane reactors
- Selective methane oxidation over promoted oxide catalysts to \( \text{C}_2 \) hydrocarbons and oxygenates
- Catalytic conversion of the light components of natural gas to alcohol-rich oxygenate
- Use of ceramic membranes to improve the selectivity of catalytic oxidation of methane to methanol

Steady-State and Transient Catalytic Oxidation and Coupling of Methane

Oxidative coupling of methane produces ethane and ethylene as primary products. Full oxidation reactions also occur on surfaces during desired radical generation steps and lead to high yields of undesired \( \text{CO}_2 \). H. Heinemann, et al., of Lawrence Berkeley Laboratory have recently shown that water enhances the \( \text{C}_2 \) selectivity on Ca-Ni-K and Li/MgO catalysts by inhibiting the oxidation of methane and of \( \text{C}_2 \) products to CO and \( \text{CO}_2 \). They have also demonstrated that its role is to decrease the concentration of sites capable of multiple exchange between gas phase and lattice oxygen. These sites, where oxygen availability appears to be high, appear to be responsible for the deleterious total oxidation pathways on these materials. These studies have been complemented with detailed surface characterization of Ca-Ni-K materials, specifically the surface density and location of K, and its essential role in the oxidative coupling reaction.

Detailed reaction transport models developed by Heinemann, et al., suggest that even selective radical generation catalysts cannot attain \( \text{C}_2 \) yields above 25 percent, because of competing gas phase oxidation reactions. These limitations can be overcome, however, by either the controlled introduction of the \( \text{O}_2 \) reactants into packed-bed reactors or by the use of oxygen or hydrogen transport membrane reactors. Specifically, these investigators have prepared doped \( \text{SrM}_{0.9}\text{Y}_{0.1}\text{O}_{2.95} \) (M=Ce, Zr) materials in membrane form. These materials allow the selective transfer of the abstracted H-atoms from one side, where the \( \text{CH}_4 \) activation occurs, to the opposite side, where they are oxidized to provide the thermodynamic driving force for the overall conversion reaction, without allowing contact between hydrocarbons and \( \text{O}_2 \). Heinemann, et al., have fabricated these materials into membrane configurations, and initial catalytic experiments are under way. They have also developed fabrication methods for the synthesis of thin films to metal oxide materials such as Ca-Ni-K oxides, which will be extended to the synthesis of proton-conducting oxides in thin film configurations.

Selective Methane Oxidation Over Promoted Oxide Catalysts

The objective of research by K. Klier, et al., of Lehigh University, is to selectively oxidize methane to \( \text{C}_2 \) hydrocarbons and to oxygenates, in particular formaldehyde and methanol, in high space time yields under milder reaction conditions than heretofore employed over industrially practical catalysts. In particular, air, carbon dioxide, or oxygen, rather than nitrous oxide, is being used as the oxidizing gas, and a wide range of reaction conditions, e.g., temperature, pressure, and gas hourly space velocity, is being explored to maximize the space time yields of the desired products. All of the investigated processes are catalytic and aimed at minimizing gas phase oxidation reactions. This research comprises the following three tasks:

- Maximizing the selective oxidation of methane to \( \text{C}_2 \) products over promoted \( \text{La}_2\text{O}_3 \) catalysts
- Selective oxidation of methane to oxygenates
- Catalyst characterization and optimization
Extensive research has been carried out with a 1 weight percent Sr/La$_2$O$_3$ catalyst provided by Amoco Oil Company. With a 50/50 methane/air reactant mixture, this catalyst is a good methyl radical generator. It was found that by doping the strongly basic 1 weight percent Sr/La$_2$O$_3$ catalyst with strongly acidic SO$_4^{2-}$, the catalyst was significantly improved for the conversion of methane into C$_2$ products. The optimum sulfate doping level was 1 weight percent SO$_4^{2-}$. As compared with the basic Sr/La$_2$O$_3$ catalyst, the sulfated catalyst had a larger surface area and showed enhancement in methane conversion, the C$_2$ hydrocarbon selectivity, and the space time yield of C$_2$ products. The SO$_4^{2-}$/Sr/La$_2$O$_3$ catalyst exhibited good stability in the 500 to 600$^\circ$C temperature range; e.g., no deactivation was observed over a 25 hour test, and it is one of the most active and selective oxidative coupling catalysts for converting methane to C$_2$ products ever reported.

Catalytic Conversion of Light Alkanes

At Sun Company, Inc., J.E. Lyons, et al., are developing a new class of materials that catalyze the direct oxidative conversion of natural gas and its light components (methane, ethane, propane and the butanes) to an alcohol-rich oxygenate for use as both alternative and reformulated transportation fuels.

The family of catalysts that Sun has produced are the first synthetic materials that are able to promote the selective transformation of an alkane to an alcohol using oxygen as the only added reagent. This new class of catalysts was discovered as a result of understanding the catalytic action of enzymatic catalyst systems that convert alkanes to alcohols. Typical of these biological systems are cytochrome P-450, which converts carbon-hydrogen bonds in the liver, and methane mono-oxygenase, which can turn methane into methanol under mild conditions in nature. Having learned how the biological systems work, Sun has designed, synthesized and tested simple synthetic versions of the more complex natural catalysts which utilize their most desirable features for application to industrial oxidation.

Lyons, et al., have produced the most active light alkane oxidation catalysts known to date and used them to convert the C$_1$-C$_4$ alkanes to their respective alcohols. The catalysts produced have three important features:

- A robust ligand system that allows them to survive the rigors of industrial processing
- High reduction potentials that allow them to continually return the catalyst to the active reduced state even under oxidizing conditions
- Inexpensive routes to the manufacture so they can be used as industrial catalysts

Lyons, et al., have entered the proof-of-concept stage for a process to convert field butanes to an environmentally friendly, high performance transportation fuel (tert-butyl alcohol). They will next begin proof-of-concept development of a process for converting propane to isopropyl alcohol, followed by a similar program for converting methane or natural gas into a methanol-rich oxide.

Direct Methane Conversion to Methanol

The objective of work by R.D. Noble, et al., of the University of Colorado, is to determine the effectiveness of combining a ceramic membrane with a catalyst in order to improve selectivity for the partial oxidation of methane to methanol. These researchers are using a non-isothermal reactor that contains a small pore ceramic membrane in efforts to improve the selectivity to methanol when methane and oxygen react at high temperature and pressure. They are also modifying ceramic membranes by growing zeolite membranes on their surfaces in efforts to improve the separation of methanol and methane.

A cooling tube located in the center of an alumina membrane tube provides a means of quenching the reaction so that complete conversion to carbon dioxide and water is not obtained. The reactor is heated from the outside so that a significant radial temperature gradient is obtained. A catalyst is located on the outside surface of the membrane. Noble, et al., have obtained significantly higher selectivities to methanol when the cooling tube is present in the reactor. Apparently it creates a low temperature zone that quenches the product stream and thus inhibits further reaction. They have varied the temperature of the outside wall, the length of the membrane (the membrane is connected to two non-porous alumina tubes so that gas can only permeate in the central section of the reactor), the type of membrane used, the diameter of the cooling tube, and the temperature of the cooling tube. Most experiments have been carried out at 500 psi, 8 percent oxygen in methane, and at a fixed flow rate, but these values have also been varied.
The combined methanol plus carbon monoxide selectivity is 85 percent, and the remaining carbon-containing product is carbon dioxide. The methanol selectivity with the cooling tube is approximately twice that obtained in the same reactor without quenching, and selectivities of 30 to 40 percent were obtained at methane conversions of 6 percent. These values are all at high oxygen conversions (80 to 90 percent of the oxygen in the feed).

Noble, et al., have prepared a silicalite zeolite membrane on the alumina membrane tube and used this for separation studies of methanol/methane and methanol/hydrogen mixtures. These studies were carried out over a range of pressures and temperatures. For conditions where not much separation was obtained with an alumina membrane alone, separation factors as high as 1,000 were obtained with the zeolite membrane, because the methanol preferentially permeated through the membrane. That is, a pore blocking process appears to take place in which the methanol occupies the zeolite pores and prevents methane or hydrogen from permeating through the membrane. These membranes show activated transport for a number of gases in single gas permeation studies.

Further studies will investigate the role of the membrane and of the catalyst in obtaining improved selectivity, with particular emphasis on the effect of membrane pore size.

NEW METHANE CONVERSION PROCESS DOUBLES YIELD OF C2 CHEMICALS

Researchers at the University of Minnesota, Minneapolis, have developed a process that produces more than 60 percent C2 yields from oxidative coupling of methane, according an article in Chemical and Engineering News, October 11, 1993.

Researchers at the University's Department of Chemical Engineering and Materials Science used a simulated countercurrent moving-bed chromatographic catalytic reactor to convert methane to C2 species. Working on a bench-scale with milliliters-per-minute quantities, they employed a samarium oxide catalyst at temperatures near 1,000 K.

The research team reports that more than 80 percent of the methane carbon is converted to C2 species and they expect that optimization will further improve these results.

The reactor's success results from rapid separation of oxygen, methane, and C2 products. This permits shifting the chemical equilibrium in an equilibrium-limited situation. Also, separations that are carried out in chromatographic columns can be used to increase conversions beyond the equilibrium limit of well-mixed reactors.

Methane coupling is not equilibrium limited. It is, simply, a low conversion process because of the necessity to prevent further oxidation of the desired products. The scientists circumvent this problem by using reaction chromatography—which separates oxygen, methane, and C2 products as they are formed.

The chemical reactor used in this work simulates the process that occurs in a countercurrent moving-bed reactor. Granular adsorbent and/or catalyst flow slowly downward against a countercurrent stream of inert carrier gas. Feed (for example, methane) is injected part-way along the column. Solid and gas flow rates are adjusted so that species that are adsorbed relatively weakly (such as ethylene) move upward with the carrier, whereas those that are adsorbed relatively strongly (such as carbon dioxide) move downward with the solid.
CHINA MAKES BID TO DEVELOP COAL-BED METHANE

According to the China Daily, experts have chosen four areas in Central and East China to explore deep coal-bed methane. A 458-meter well has been sunk to study methane reserves.

Methane exploration is one of seven projects in a program to help China use its coal in a more efficient and environmentally friendly way. The program is financed, in part, by the United Nations Development Program.

Aside from methane exploration, the $17 million package covers:

- Recovery and use of chemicals from coking
- Circulating fluidized-bed combustion technology
- Control of atmospheric pollution from coal combustion
- Preventing hazardous groundwater inflows in coal mines
- Advanced technology and safety measures to mine thick coal seams
- Development of technology for hot gas desulfurization
FORTY TRILLION CUBIC FEET OF NATURAL GAS IDENTIFIED IN HYDRATES ON ALASKAN NORTH SLOPE

A United States Geological Survey (USGS) project is assessing the production characteristics and economic potential of continental gas hydrates, focusing on Northern Alaska. A report on the project was presented by T.S. Collett, et al., at the Fuels Technology Contractors Review Meeting held at the United States Department of Energy's Morgantown Energy Technology Center, in Morgantown, West Virginia in November.

This project was designed to obtain a clear understanding of the gas hydrate resource potential in Northern Alaska and to develop the extraction technology necessary to economically produce gas hydrates. This study has resulted in the discovery of an estimated 40 trillion cubic feet of gas trapped as gas hydrates, or about twice the volume of conventional gas in the Prudhoe Bay field. On the North Slope, the zone in which methane hydrates may exist is areally extensive beneath most of the Arctic coastal plain and extends to depths greater than 1,000 meters in the Prudhoe Bay area.

Gas hydrates have been conclusively identified and tested in a Prudhoe Bay field well and are inferred to occur in a series of discrete reservoirs overlying the Eastern part of the Kuparuk River field, the Southern part of the Milne Point field, and the Western part of the Prudhoe Bay field. Recently, multi-channel seismic data from Northern Alaska has revealed the first ever observed onshore gas hydrate Surface Simulating Reflector (SSR). This prominent reflector in the Prudhoe Bay area, coincident with the base of the gas hydrate stability zone, is postulated to be the result of free-gas trapped stratigraphically downdip below gas-hydrate-bearing sediments. The discovery of this SSR confirms the occurrence of gas hydrates on the undrilled offshore Alaskan continental shelf.

The presence of free-gas trapped below the gas hydrates in the Prudhoe Bay area is analogous to the Messoyakha gas-hydrate/free-gas accumulation in Western Siberia, from which approximately 70 billion cubic feet of gas has been produced from hydrates alone. The production history of the Messoyakha field has demonstrated that gas hydrates are an immediate producible source of natural gas and that production can be started and maintained by conventional methods. The geologic comparison of the Messoyakha and Prudhoe Bay-Kuparuk River gas hydrate accumulations suggests that the Alaskan gas hydrates may also be a producible source of natural gas.

Other ongoing gas-hydrate-related studies in the USGS have focused on:

- The potential geologic hazards of Arctic gas hydrates
- The relation between atmospheric methane, a greenhouse gas, and destabilized in situ gas hydrates

United States, Canadian, and Russian researchers have described numerous drilling and production problems attributed to the presence of gas hydrates, including uncontrolled gas releases during drilling, collapsed casings, and gas leakage to the surface. Several reports have documented geologic problems attributed to the presence of gas hydrates. Analysis of gases trapped in ice cores indicates that contemporary atmospheric methane concentrations and their rate of increase are unprecedented over the last 160,000 years. Numerous researchers have suggested that destabilized gas hydrates may be contributing to this buildup in atmospheric methane. One of the areas of greatest concern is the thermally unstable continental shelf of the Arctic Ocean. Because little is known about the geology of the Arctic Shelf, onshore Alaska gas hydrate studies are being used to develop geologic analogs for potential Arctic Shelf gas hydrate occurrences.

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SYNTIIL!TIC FUELS REPORT, MARCH 1994
STATUS OF NATURAL GAS PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since December 1993)

FUELCO SYNHYTECH PLANT – Fuel Resources Development Company (G-10)

Fuel Resources Development Company (FuelCo) held ground breaking ceremonies in May 1990 for their Synhytech Plant at the Pueblo, Colorado landfill. The Synhytech Plant, short for synthetic hydrocarbon technology, will convert the landfills’ methane and carbon dioxide gas into clean burning diesel fuel as well as naphtha and a high grade industrial wax.

The technology is said to be the world’s first to convert landfill gases into diesel motor fuel. It was developed by FuelCo, a wholly owned subsidiary of Public Service Company of Colorado, and Rentech Inc. of Denver, Colorado. FuelCo is planning to invest up to $16 million in the project with Rentech having the option to purchase 15 percent of the plant. Ultrasystems Engineers and Constructors is designing and building the project.

The plant is expected to produce 100 barrels of diesel, plus 50 barrels of naphtha and 80 barrels of high grade wax per day. It is estimated that the Pueblo site will sustain a 235 barrel per day production rate for about 20 years. FuelCo estimates that diesel fuel can be produced for about $18 per barrel.

The process takes the landfill gas—which is about 52 percent methane and 40 percent carbon dioxide—breaks it down and passes it through an iron-based slurry-phase catalyst, and extracts diesel fuel, naphtha and wax.

According to vehicle test results at high altitude, the Synhytech diesel was 35 percent lower in particulate emissions and produced 53 percent fewer hydrocarbons and 41 percent less carbon monoxide in the vehicle exhaust. It contains no sulfur and only low levels of aromatics, and no engine modifications are required. Plant construction was complete in December 1991 and the first crude product was produced in January 1992.

In early 1993 Public Service Company of Colorado sold its Fuel Resources Development Company subsidiary, along with the Synhytech pilot plant to Rentech.

Project Cost: $16 million

MOSSGAS SYNFUELS PLANT – South African Central Energy Fund (70 percent), Engen Ltd. (30 percent optional) (G-20)

In 1988 the South African government approved a plan for a synthetic fuels from offshore natural gas plant to be located near the town of Mossel Bay on the southeast coast. Gas for the synthesis plant will be taken from an offshore platform which was completed in 1991. The SASOL Synthol technology was selected for the project.

Construction of the onshore plant was completed in mid-1992. Commercial production was achieved in January 1993 at 80 percent of design capacity.

The breakeven point for the project will be reached with crude oil prices of $35 per barrel. Engen is the project manager and will be the operator of the facility. The project was financed 80 percent by the Central Energy Fund and 20 percent by commercial loans.

Based on the original design, the Mossgas complex was to produce only automotive fuels and the license from Sasol for the synthesis units reads accordingly. Chemicals such as aldehydes and ketones are hydrogenated to alcohol and the entire alcohol production, with the exception of the heavy alcohols, was to be blended into gasoline. In 1993 automotive fuels are not the most valuable products. Mossgas has been investigating the scope for increased production and opportunities to produce value added products.

Increasing the syngas production capacity is also being investigated, because the synthesis units have considerable spare capacity and only an additional reforming train will be required. In addition, the refinery gas condensate processing capacity could be increased significantly for a relatively minor investment.

Gas reserves, located in 350 feet of water, 55 miles off the Southeast coast of South Africa, are sufficient to operate the synthesis facility for 30 years at design rate.

Gas and condensate arrive onshore in separate pipelines. In the Natural Gas Liquid Recovery plant any hydrocarbons heavier than propane are removed from the gas stream yielding lean natural gas. The lean gas is fed to a two-stage methane reforming plant. The first stage consists of a tubular reforming plant which is followed by a secondary partial oxidation plant. The capacity of the three-train reforming plant would be sufficient for the production of 7,000 tons per day of methanol.

Using an iron-based catalyst, the synthesis gas from the natural gas reforming plant is catalytically converted to predominantly light olefinic hydrocarbons. The tailgas from Synthol is sent to the Taiglas Treatment plant where products (propylene, butylene and C5+ condensate) are cryogenically removed before the gas is recycled back to a natural gas reforming plant. Hydrocarbons from Synthol are refined by conventional methods to produce the final fuels.

SYNTHETIC FUELS REPORT, MARCH 1994
STATUS OF NATURAL GAS PROJECTS (Underline denotes changes since December 1993)

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NEW ZEALAND SYNFUELS PLANT - Methanex New Zealand Limited (G-30)

The New Zealand Synthetic Fuels Corporation Limited (Synfuel) Motunui plant was the first in the world to convert natural gas to gasoline using Mobil's methanol-to-gasoline (MTG) process. Construction began in early 1982 and the first gallon of gasoline was produced in October 1985. In the first 8 months of commercial production the plant produced 448,000 tonnes of gasoline or about 35 percent of New Zealand's total demand for that period.

During the first two years of operation, the Synfuel plant suffered several shutdowns in the methanol units thus causing production shortfalls despite reaching the one million tons of gasoline mark in 1988. A successful maintenance turnaround and several improvements to the MTG waste water plant have improved efficiency considerably. In 1990 the plant produced about 12,000 barrels of gasoline per day. This is about 34 percent of New Zealand's gasoline needs.

The plant is located on the west coast of New Zealand's North Island in Taranaki. It is supplied by the offshore Maui and Kapuni gas fields. The synthetic gasoline produced at the plant is blended at the Marsden Point refinery in Whangarei. The plant is a tolling operation, processing natural gas owned by the government into gasoline for a fee. Synfuels, thus does not own the refined product.

Synfuel was owned 75 percent by the New Zealand government and 25 percent by Mobil Oil of New Zealand Ltd. However, the Petroleum Corporation of New Zealand (Petrocorp) entered an agreement with the New Zealand government to assume its 75 percent interest in the corporation. The New Zealand government had been carrying a debt of approximately $700 million on the plant up to that point. Petrocorp is owned by Fletcher Challenge, Ltd.

Since the change in ownership, a pipeline has been built between the Synfuel plant and the Petralgas methanol plant in the Waitara Valley. This addition means that, when the price of distilled methanol is high, a percentage of Synfuel crude methanol can be sent via the pipeline to Petralgas for distillation. When the price of gasoline is high, Petralgas methanol can be sent via the pipeline to Synfuel and be converted into gasoline.

The synfuel plant produced a record 562,000 tonnes of gasoline in the first 6 months of 1991. A percentage of crude methanol was pipelined to Fletcher's Petralgas plant to produce 186,000 tonnes of chemical grade methanol.

The plant was designed to produce 4,400 tonnes of methanol per day. Due to plant modifications, Synfuel is capable of producing 5,000 tonnes of crude methanol per day. Equally, the plant was designed to produce 570,000 tonnes of gasoline per year. Synfuel can produce over 630,000 tonnes of gasoline, or 34 percent of New Zealand's gasoline needs.

In February 1993, Methanex Corporation of Canada said it would buy the methanol assets from Fletcher Challenge Ltd., in a transaction with an indicated value of US$730 million.

Fletcher Challenge would receive $250 million in cash and about 74 million common shares of Methanex in the proposed deal. The transaction would make Methanex the world's largest producer and marketer of methanol, and would make Fletcher Challenge the largest shareholder in the petrochemicals concern.

Following completion of the asset purchase and a share issue, Fletcher Challenge would hold about 43 percent of Methanex's shares. The stake held by current leading shareholder Metallgesellschaft would fall to about 10 percent from its current 32 percent.

Fletcher Challenge, which owns the Cape Horn methanol plant in Chile, is the world's largest methanol producer, just ahead of Saudi Arabian Basic Industries Corporation.

SHELL MALAYSIA MIDDLE DISTILLATES SYNTHESIS PLANT - Shell MDS (60 percent), Mitsubishi (20 percent), Petronas (10 percent), Sarawak State Government (G-50)

The world's first commercial plant to produce middle distillates from natural gas in Malaysia, started up in April 1993. The $660 million unit is 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 is Shell MDS. 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...
STATUS OF NATURAL GAS PROJECTS (Underline denotes changes since December 1993)

COMMERCIAL PROJECTS (Continued)

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 paraffins and waxes, can be varied to match market demand. Shell will use its own gasification technology to produce the synthesis gas.

Four reactors for the heavy paraffin synthesis unit, said to be the largest in the world, have been delivered to the plant site. These vessels were built in Italy, but overall construction is being handled by JGC Corporation of Japan.

Project Cost: $660 million