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Oil Shale: The U.S. Takes Another Look at a Huge Domestic Resource

Back in the late 1970s and early 1980s, a multitude of petroleum companies with some help from the U.S. government invested some $4 billion in demonstration projects to produce oil from the country's extensive oil shale resources, found mostly in Colorado, Utah and Wyoming. The plan, precipitated by oil shortages caused by the Arab Oil Embargo and the 1979 revolution in Iran, was to reduce U.S. dependence on oil imports.

At the time, the belief was that oil could be produced economically from shale if oil prices were around $40/bbl. The ambitious endeavor fizzled out partly because the supply crisis had passed (oil prices were as low as $10/bbl by 1984) and partly because of the difficulty of developing practical ways to extract oil from shale.

With recent oil prices above $70/bbl, the aspirations of oil-shale proponents have been revived. Under a new program, the Bureau of Land Management (BLM; Washington, DC; www.blm.gov) has accepted industry proposals for six 160-acre oil shale research, development and demonstration (RD&D) leases on public lands in Colorado and Utah. Final granting of the leases is not expected for two years, during which time BLM will conduct site-specific environmental evaluations (to be completed by summer) and a "programmatic environmental impact statement" that will analyze the overall impact of the proposed program.

Four companies have been selected to participate in the program: Chevron Shale Oil Co. (Houston, TX; www.chevron.com); EGL Resources, Inc. (Midland, TX; www.eglresources. com); Oil Shale Exploration Co., LLC (OSEC; Mobile, AL; www.osecllc.com) and Shell Frontier Oil & Gas, Inc. (Houston, TX; www.shell.com), which submitted proposals for three 160-acre parcels.

A company that is granted a lease will have 10 years to demonstrate commercial feasibility of its process. If the project is successful, the company can renew the lease and may lease an additional, contiguous area of 4,960 acres reserved for future commercial use.

Initially, BLM selected six companies, but ExxonMobil Corp. (Irving, TX; www.exxonmobil.com) and Oil-Tech, Inc. (Vernal, UT; www.oiltech inc.com) were dropped from the program. The reasons, according to BLM, were that their proposals didn't show they would conclude their RD&D in a timely fashion and didn't provide for the recovery of other minerals, such as nahcolite (baking soda), that occur in the shale.

The U.S. oil shale deposits contain an estimated 1.5–1.8 trillion bbl of oil, according to a 2005 report done by Rand Corp. (Santa Monica, CA; www.rand.org) for the U.S. Dept. of Energy (Washington, DC; www.doe.gov). Of this, better than 800 billion bbl may be recoverable — more than triple the proven oil reserves of Saudi Arabia. In many areas, the oil content of the shale is above 30 gal/ton. More than 70% of the shale underlies federal land.

Taking a Page from Canada's Successful Oil Sands Program

Oil shale is sedimentary rock that contains bitumen. When the rock is heated the bitumen is released as kerogen, which can be fed to a refinery after being hydrotreated. However, various methods for extracting kerogen were tested in the 1970s and 1980s, without success. Most involved mining shale and heating it in retorts, and both the retorting and environmental problems, including disposal of the huge volumes of spent shale, proved to be formidable challenges. Since then, with the exception of Shell, the petroleum industry has put little effort into oil-shale technology.

Critics decry the lack of long-term commitment on the part of industry and government. They point to the example of Canada, where a thriving oil-sands industry has evolved from several decades of persistence and cooperation between industry, the federal and Alberta provincial governments, and research institutions (including the Alberta Research Council).

A key recommendation of the report from Rand Corp. is that DOE should invest in R&D. "It does not make sense that oil shale is missing from the DOE's R&D portfolio," states the report. Also, Canada's oil-sands program is cited as a model for potential U.S. oil-shale development by a 2004 report on oil shale, done by AOC Petroleum Support Services, LLC (Washington, DC) for DOE's Office of Naval Petroleum and Oil Shale Reserves. "There are direct parallels between tar sand and oil shale with respect to resource size, resource quality, mining, recovery and upgrading technologies, and production certainty," notes the report. "In nearly all respects oil shale compares favorably to tar sands."

One of the authors of that report, consultant James Bunger of Salt Lake City, UT, (www.jwba.com), says that years of consistent improvement in oil-sands processing have resulted in production costs that are as low as $10/bbl. Canada's production of oil from oil sands now exceeds 1 million bbl/d and is projected to reach 2.7 million bbl/d by 2015.

A plan that might lead the U.S. along a similar path is forming at the federal level. An Unconventional Fuels Task Force has been formed under the direction of the Energy Policy Act of 2005 (EPACT) to investigate the prospects for increasing domestic production of liquid fuels from coal, oil shale, tar sands and heavy oil. The task force is made up of representatives from DOE, the Dept. of Interior, Dept. of Defense (DOD), and the governors of Colorado, Utah, Wyoming, Kentucky and Mississippi.

The task force was scheduled to submit its initial recommendations to President Bush and Congress by June. Since many of the resources are on public land, one recommendation is to make it easier for industry to gain access to those resources and to streamline the regulatory process, says Tony Dammer, program manager for the task force and director of DOE's Office of Naval Petroleum and Oil Shale Reserves. The report also calls for fiscal incentives, such as tax credits, accelerated capital depreciation, and delayed payment of royalties. Dammer adds that DOD is considering long-term purchase agreements for unconventional fuels in order to guarantee a market for producers. "This first report is basically a list of what we are thinking," he says. "A more-detailed plan will be presented at the end of this year."

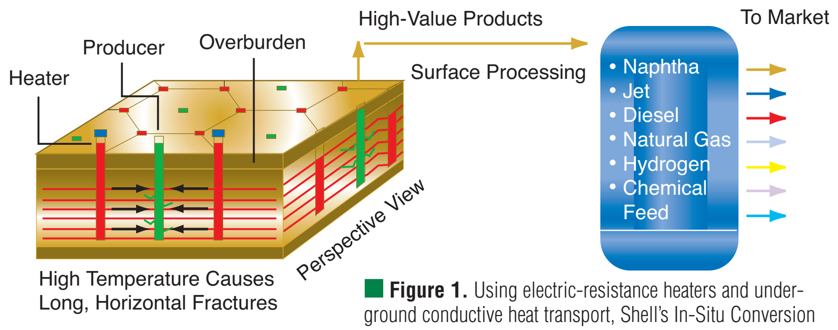

Figure 1. Using electric-resistance heaters and underground conductive heat transport, Shell's In-Situ Conversion Process (ICP) enhances the natural maturation of kerogen by slow heating. Shell expects this process to be competitive with oil prices in the range of $30/bbl.

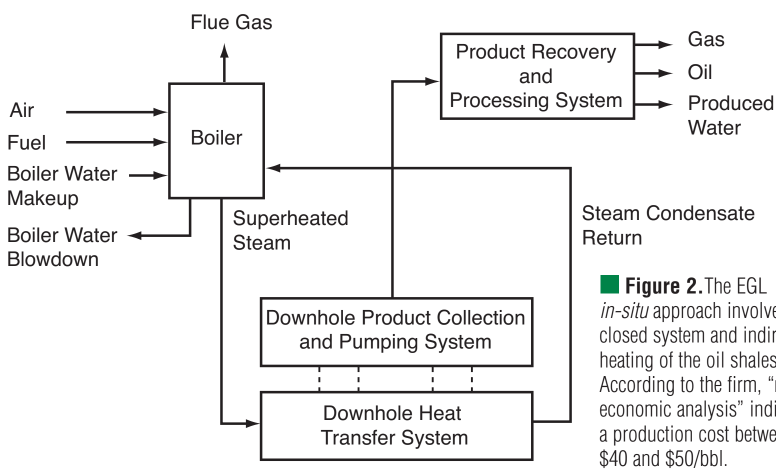

Figure 2. The EGL *in-situ* approach involves a closed system and indirect heating of the oil shales. According to the firm, "rough economic analysis" indicates a production cost between $40 and $50/bbl.

In-situ technologies

The new oil-shale extraction processes include various *in-situ* methods in which the shale is heated in the ground to liberate oil, which is pumped out through wells. This approach avoids the cost and environmental problems of mining and disposal of spent shale.

Shell, the leader in the field, has been testing an *in-situ* process for 10 years on its property in Rio Blanco County, CO. The most recent test has produced 1,500 bbl of light oil, plus associated gas. "We've been working on this process since 1982 and have invested tens of millions of dollars," says Terry O'Connor, vice-president for external and regulatory affairs with Shell Exploration & Production Co. in Denver, CO.

In Shell's In-situ Conversion Process (ICP), holes are drilled to depths up to 2,000 ft, and electrodes are inserted to form what amounts to a large resistance heater. The rock formation is gradually heated to 650–700°F over a period of 2–3 yr and produces a typical mixture of 2/3 light oil and 1/3 natural gas (Figure 1). The energy return on investment (EROI) is about 3:1 (three energy units produced for each unit consumed). O'Connor says that Shell expects the process to be competitive with oil prices in the range of $30/bbl.

Shell plans to conduct the first pilot test of the ICP on one of its BLM leases. In preparation for that, the company plans to test a freeze-wall system that will be used to keep groundwater out of the working area. Holes will be drilled around the site, then pipes will be inserted and filled with chilled fluid to create a wall of ice in the surrounding rock — similar to the freeze walls used in mining and construction. Groundwater will be pumped out of the isolated area, and the freeze wall will act as a barrier to prevent groundwater inflow and to contain the hydrocarbons.

At its second leased site, Shell will test the recovery of nahcolite by circulating pressurized hot water. The third site will be used to test a second-generation heater designed to improve the efficiency of the ICP. In the new design, the electrodes will be connected in triangular patterns underground.

An *in-situ* process that uses superheated steam to extract kerogen from oil shale will be employed by EGL Resources, an independent oil-production company. Initially, the section to be treated will be dewatered by installing a circle of extraction and monitoring wells. "This will probably be cheaper than freezing," says Glenn Vawter, manager of EGL's Oil Shale Div., who is located in Glenwood Springs, CO.

For the demonstration, EGL plans to drill holes about 40 ft apart through the 1,000 ft of overburden, and about 280 ft into the shale, then drill horizontally through the deposit (for a commercial operation, the holes would be drilled to the bottom of the shale layer; Figure 2). Pipes will be inserted into the holes and superheated steam will be pumped in to heat the kerogen. "This is a closed system, so the pipes act like a radiator," says Vawter. As the temperature increases, steam may be replaced by a high-temperature heat-transfer fluid.

Product will be recovered through four vertical wells, using coiled tubing to enhance the recovery. About 2/3 to 3/4 of the product will be recovered as liquid and the rest as natural gas. Vawter says a "rough economic analysis" indicates a production cost ranging from $40/bbl to $50/bbl.

Three companies that have proprietary *in-situ* processes have formed an alliance and have agreed to cross-license their technologies to share the development risk. They are: Independent Energy Partners, Inc. (IEP; Englewood, CO; www.iepm.com); Petro Probe, Inc. (Kalispell, MT; www.earthsearch.com), and Phoenix Wyoming, Inc. (Thornton, CO; www.phxwy.com). "There are synergies between the processes," says William Pelton, president of Phoenix Wyoming. "We plan to field-test all three and commercialize whichever turns out best." He adds that the companies have access to 1,500 acres of shale land in Colorado's Piceance Basin, with the expectation of obtaining more.

Phoenix Wyoming drills a pattern of boreholes and inserts microwave elements to heat up the shale. The process has been tested in permafrost in northern Ontario and proved to be “50 times faster than thermal conduction,” says Pelton.

In Petro Probe’s process, hot gases are injected down a borehole and leach kerogen from the shale. The kerogen is recovered as gas through the same hole and is condensed to recover liquid.

IEP’s process will use the 750–850°C waste heat from a solid-oxide fuel cell to heat the shale. The fuel cell will be put down a well and fueled by product gas and air to produce electricity, which would be offered for sale from a commercial operation. The expected EROI is about 9:1, says Pelton.

Chevron is developing an *in-situ* process that uses hot carbon dioxide to liberate kerogen. CO_2, which is used in enhanced oil recovery, acts as a surfactant as well as a means of heating the shale. The company plans to test the process by drilling up to five test wells. Additional fracturing will be achieved by subjecting the formation to thermal cycles, using hot CO_2. Once fracturing is complete, the formation will be heated slowly by circulating pressurized CO_2, which will be reheated and recycled.

Supercritical CO_2 is combined with radio-frequency (RF) energy in an *in-situ* process being developed by Raytheon Co.’s Integrated Defense Systems (IDS, Tewksbury, MA; www.raytheon.com) and CF Technologies, Inc. (Hyde Park, MA; www.cftechnologies.com). In this concept, a rod is inserted in a borehole and transmits RF energy through the formation, heating hydrocarbon molecules.

An array of RF rods, spaced “many meters” apart, could heat a formation within “a couple of months,” says Lee Silvestre, director of Mission Innovation at IDS. In comparison with conventional heating, RF is “like a microwave oven compared to a conventional oven,” she says.

Once the formation is heated, supercritical CO_2 is injected and acts as a solvent for the kerogen. The kerogen and CO_2 readily separate as the pressure is released at the recovery well, and the CO_2 is recovered for reuse. Raytheon field-tested the RF component in Colorado many years ago and has recently tested CF Technologies’s process in the laboratory. “The tests indicate we could extract up to 98% of the kerogen, with an EROI of 4–5:1,” says Silvestre.

ExxonMobil also plans to use *in-situ* technology, starting with hydraulic fracturing, a common oil-field procedure. “We are investigating multiple methods for building heated fractures, which may be heated by electrical current or by circulation of hot fluids,” says a company spokesman. ExxonMobil has an interest in approximately 300,000 acres of oil-shale holdings in Colorado’s Piceance Basin.

Although *in-situ* processes offer environmental advantages over surface retorting in that they eliminate mining and disposal of spent shale, critics contend that the technology has the potential to pollute aquifers. “You can isolate a project while you’re working on it, but it takes a long time to heat a formation and a long time for it to cool down. So after a project is finished how do you know what’s being leached into the water table?" says one anonymous critic.

In economic terms, *in-situ* technology appears best suited to locations like the Piceance Basin, where the deposits are from 500-ft to more than 2,000-ft thick, with as much as 1,000 ft of overburden, according to the Rand report. However, where there is little overburden and where the shale layer is not so thick, mining and surface retorting may be the best option, says Bunger.

Surface retorting

Five of the BLM lease sites are in the Piceance Basin and all of the participating companies plan to use *in-situ* processes. The sixth site is in Utah, where the shale deposits tend to be shallower and closer to the surface, and the plan there is to use surface retorting.

The Utah site is the White River Mine, near Vernal, where about 50,000 tons of shale was mined and stockpiled some 20 years ago. OSEC, the company selected for that site, plans to process part of that shale for its initial tests, using a retort from Umatac Industrial Processes (Calgary, AB; www.uma.aecom.com). As part of its agreement with BLM, OSEC will also make shale available to other companies for testing and will open up the mine early in its RD&D program.

Umatac's retort, called the Alberta Taciuk Processor (ATP), was originally developed with the sponsorship of the Alberta Dept. of Energy (Edmonton) for oil sands and was subsequently adapted for oil shale. The retort is a horizontal, rotating cylinder that has four compartments for: preheating shale to 250°C to remove water; pyrolysis at 500°C to crack the kerogen to vapors, which are withdrawn through a central tube and condensed; spent shale combustion for process heat; and heat recovery from the spent shale.

A 4,500-bbl/d demonstration ATP plant was operated in Gladstone (Queensland, Australia), on the 2.6-billion-bbl Stuart shale resource, by Southern Pacific Petroleum N.L. (Brisbane) and Suncor Energy, Inc. (Calgary, AB). From 2000 to 2004, the plant produced 1.7 million bbl of oil, which was hydrotreated to produce gasoline and fuel oil, says ATP inventor William Taciuk, executive vice president of Umatac.

Taciuk says that a basic advantage of a rotary kiln is that it avoids the agglomeration and channeling problems typical of the vertical retorts tested a generation ago. Another benefit is that all the shale is treated and essentially all the energy recovered, since residual carbon is burned to fuel the process. "With an *in-situ* process you can't guarantee how much oil you will get from a formation," he says.

Initially, OSEC will process White River shale at Umatac's 5-ton/h pilot unit in Calgary. The next step, if the project goes forward, will be to install a demonstration plant at the mine.

A retort system that uses a series of three rotary kilns (on a 5-deg incline) to pyrolize shale has been developed by Syntec Energy, LLC (Lindon, UT). Shale is crushed to 0.125-0.25-in. dia., fed into the bottom of the first kiln, and moved along by baffles while it is preheated and dried by hot air blown from the opposite end. In the second kiln, kerogen is vaporized and entrained by hot gases, which carry the vapors back through the feed entrance to a separation and oil-recovery column. In the third kiln, the shale is cooled by ambient air, then the heated air is used for preheating in the first kiln.

In a commercial plant, the hot gases used for liberating the kerogen would come from a coal-gasification facility, the product of which has a high hydrogen content. In tests, this gas has been shown to enhance the yield and quality of the kerogen, says Rosalie Smith, president of Syntec. Since coal gasification takes place at 2,500°F, part of the waste heat would be used to produce electricity via a gas turbine. Accounting for the sale of electricity, she estimates that a 15,000-bbl/d plant could produce oil for about $17/bbl, including mining, but prior to hydrotreating.

A stationary, vertical retort that is said to avoid the caking and plugging problems of traditional vertical designs has been developed by Oil-Tech. Crushed shale of less than 0.5-in. dia. is fed into the top of the retort and vaporized at 900–1,200°F by electrical resistance heaters located on the vessel wall.

Caking and plugging are eliminated by baffles that redirect the flow of the shale and by extracting the vapor quickly to a condenser, so that it doesn't condense inside the retort, says Romit Bhattacharya, president of Oil-Tech.

Spent shale exits the vessel at 900°F and goes to a fluidized-bed cogeneration unit that provides supplemental power to the retort. This leaves a fine, benign powder that can be used to fill in the mined cavities.

Oil-Tech has tested the process in a 24-bbl/d unit and has produced about 250 bbl of oil over the past two years, says Bhattacharya. The company is now building a 1,000-bbl/d retort, which will be the standard size. "Rather than build large retorts, we plan to offer clusters of 1,000-bbl/d units," he says. "This will make it easier to scale up production, and a retort can be shut down for maintenance without having a major impact on a plant."

Bhattacharya says the energy consumption in steady-state operation is only 4–5% of the energy produced. The retorting cost is about $4–7/bbl, he says, and the cost of room-and-pillar mining ranges from $10–30/ton (with oil production of around one bbl/ton).

Another vertical retort process is being developed by Brent Fryer, an independent entrepreneur located in St. George, UT. Fryer declines to give details, except to say that the retort has no moving parts and pyrolysis is fueled by a combination of burning the char and recovering heat from the spent shale. He says the process has yielded 2 bbl/d of oil from a 2-ton/d pilot unit, using shale that contained 42 gal/ton of oil.

Given the outlook for petroleum, there seems to be little doubt that the U.S. will have an oil-shale industry. The question is, when? The DOE report by Bunger, *et al.* (box, p. 7), said shale oil production could reach 2 million bbl/d by 2020, *if* government and industry agreed on the urgency of a program. Today, Bunger says, "we were probably a little aggressive about that. The way things are now, I'd say we could have a 1-million-bbl/d industry by 2020." CEP

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