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Oil Shale: History, Incentives, and Policy

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Oil Shale: History, Incentives, and Policy

Summary

Oil shale is prevalent in the western states of Colorado, Utah, and Wyoming. The resource potential of these shales is estimated to be the equivalent of 1.8 trillion barrels of oil in place. Retorted oil shale yields liquid hydrocarbons in the range of middle-distillate fuels, such as jet and diesel fuel. However, because oil shales have not proved to be economically recoverable, they are considered a contingent resource and not true reserves. It remains to be demonstrated whether an economically significant oil volume can be extracted under existing operating conditions. In comparison, Saudi Arabia reportedly holds proved reserves of 267 billion barrels.

Federal interest in oil shale dates back to the early 20th Century, when the Naval Petroleum and Oil Shale Reserves were set aside. Out of World War II concerns for a secure oil supply, a Bureau of Mines program began research into exploiting the resource. Commercial interest followed during the 1960s. After a second oil embargo in the 1970s, Congress created a synthetic fuels program to stimulate large-scale commercial development of oil shale and other unconventional resources. The federal program proved short-lived, and commercially backed oil shale projects ended in the early 1980s when oil prices began declining.

The current high oil prices have revived the interest in oil shale. The Energy Policy Act of 2005 (EPACT) identified oil shale as a strategically important domestic resource, among others, that should be developed. EPACT also directed the Secretary of Defense to develop a separate strategy to use oil shale in meeting Department of Defense (DOD) requirements when doing so is in the national interest. Tapping unconventional resources, such as oil shale, has been promoted as a means of reducing dependence on foreign oil and improving national security.

Opponents of federal subsidies for oil shale argue that the price and demand for crude oil should act as sufficient incentives to stimulate development. Projections of increased demand and peaking petroleum production in the coming decades tend to support the price-and-supply incentive argument in the long term.

The failure of oil shale has been tied to the perennially lower price of crude oil, a much less risky conventional resource. Proponents of renewing commercial oil shale development might also weigh whether other factors detract from the resource's potential. Refining industry profitability is overwhelmingly driven by light passenger vehicle demand for motor gasoline, and oil-shale distillate does not make ideal feedstock for gasoline production. Policies that discourage the wider use of middle-distillates as transportation fuels indirectly discourage oil shale development. Because the largest oil shale resources reside on federal lands, the federal government would have a direct interest and role in the development of this resource.

This report will be updated as new developments occur.

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Oil Shale: History, Incentives, and Policy

Introduction

Projections that peak petroleum production may occur in the coming decades, along with increasing global demand, underscore the United States' dependence on imported petroleum. After Hurricanes Katrina and Rita, the spike in crude oil price and the temporary shutdown of some Gulf Coast refineries exacerbated that dependency. With imports making up 65% of the United States' crude oil supply and the expectation that the percentage will rise, proponents of greater energy independence see the nations's huge but undeveloped oil shale resources as a promising alternative.¹

Oil shales are prevalent throughout the United States. Their kerogen content is the geologic precursor to petroleum. The most promising oil shale resources occur in the Green River formation that underlies 16,000 square miles of northwestern Colorado, northeastern Utah, and southwestern Wyoming (**Figure 1**). Approximately 72% of the land overlying the Green River Formation is federally held.² The formation is estimated to contain more than 8 trillion barrels of shale oil in place; however, much of the formation has been considered too thin, too deep, or too low in yield to economically develop using older technology. The former Office of Technology Assessment (OTA) estimated in 1980 that 1.8 trillion barrels appeared marginally attractive to production, based on deposits that would yield 15 gallons per ton and were at least 15 feet thick.³ In a more recent analysis, the portion of the formation yielding greater than 10 gallons per ton was estimated to contain 1.5 trillion barrels.⁴ Because oil shales have not been proven economically recoverable, they are considered contingent resources and not true reserves.⁵ By comparison, the

¹ U.S. DOE Energy Information Administration (EIA), *Monthly Energy Review January 2006*, Table 1.7, Overview of U.S. Petroleum Trade, at [http://www.eia.doe.gov/emeu/mer/pdf/pages/sec1_15.pdf], visited Feb. 17, 2006.

² Thomas Lonnie, Bureau of Land Management, Testimony before the Senate Energy and Natural Resources Committee, Oversight Hearing on Oil Shale Development Effort, Apr. 12, 2005.

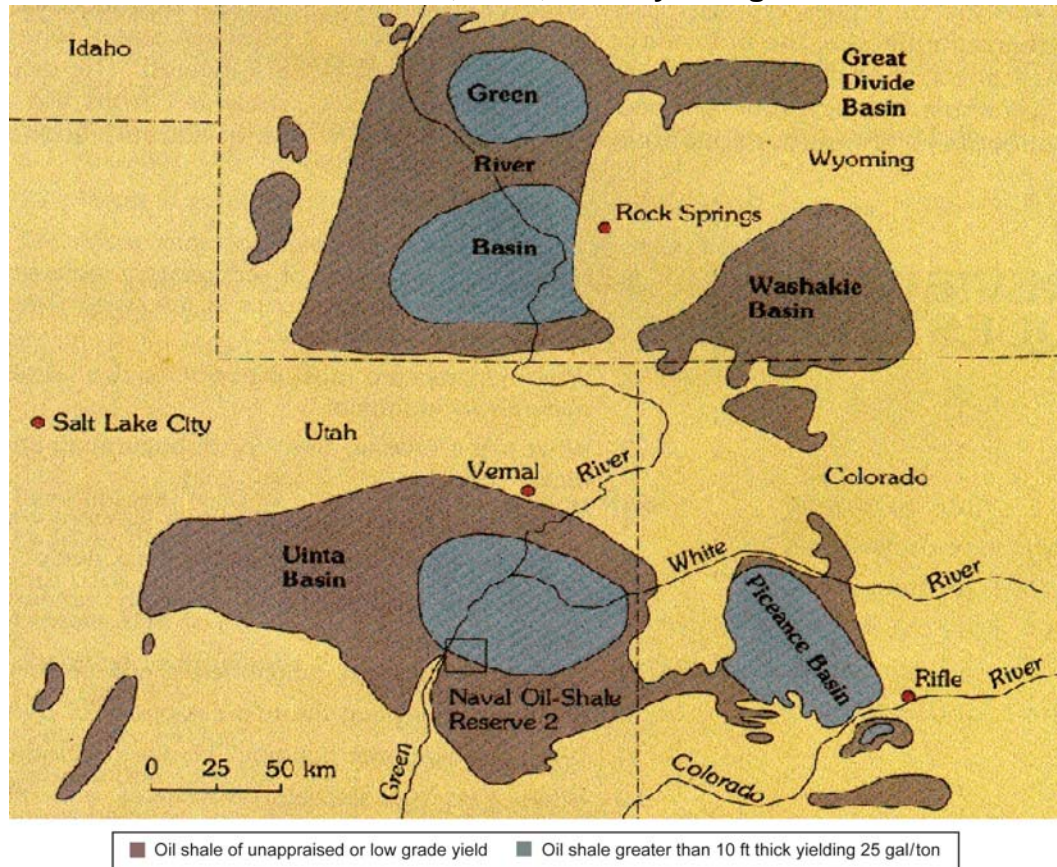
³ Office of Technology Assessment, *An Assessment of Oil Shale Technologies*, 1980, pp. 89-91, NTIS order #PB80-210115.

⁴ James W. Bungler and Peter M. Crawford, "Is oil shale America's answer to peak-oil challenge?" *Oil & Gas Journal*, Aug. 9, 2004.

⁵ The Society of Petroleum Engineers defines true reserves as "those quantities of petroleum which are anticipated to be commercially recoverable from known accumulations from a given date forward." See [http://www.spe.org/spe/jsp/basic/0,,1104_1575_1040460,00.html] (viewed Feb. 17, 2006).

conventional proved oil reserves of the United States are less than 22 billion barrels, and Saudi Arabia's are reportedly 267 billion barrels.⁶

Figure 1. Distribution of Oil Shale in the Green River Formation of Colorado, Utah, and Wyoming



Source: U.S. Geologic Survey, Circular 523 (1965), as reproduced by the U.S. Department of Energy in *Strategic Significance of America's Oil Shale Resources*, Mar. 14, 2005.

Note: The Green River formation may contain more than 8 trillion barrels of shale oil in place, with an estimated 1.8 trillion barrels marginally attractive to production. The United States holds proved reserves of less than 22 billion barrels of conventional crude oil, compared with Saudi Arabia's reported 267 billion barrels.

In the early 20th century, three oil shale reserves were set aside on federal lands out of concern for the Navy's petroleum supply. Naval Oil Shale Reserves (NOSRs) Nos. 1 (36,406 acres) and 3 (20,171 acres) are located 8 miles west of Rifle, Colorado, in Garfield County. Reserve No. 2 (88,890 acres) in Carbon and Uintah Counties, Utah, has been transferred to the Ute Indian Tribe. NOSR No.1 has been estimated to contain more than 18 billion barrels of shale oil in place.⁷ As much as

⁶ U.S. DOE EIA, *International Petroleum (Oil) Reserves and Resources*, at [<http://www.eia.doe.gov/emeu/international/oilreserves.html>], visited Feb. 17, 2006.

⁷ U.S. DOE, *Naval Petroleum & Oil Shale Reserves, Annual Report of Operations Fiscal Year 1995* (DOE/FE-0342).

2.5 billion barrels of oil may be recoverable from shale yielding 30 gallons of oil or more per ton. NOSR No. 3 is not considered to have commercial value.

Oil shale production has faced unique technological and environmental challenges. The hydrocarbon resource is bound up in the shale and is not free to flow like petroleum. In previous attempts at production, conventional subsurface and strip mining methods were combined with high-temperature processing (*retorting*) to extract petroleum-like distillates. Not only was a plentiful water supply required, but certain processing methods had associated groundwater contamination issues. Unlike conventional petroleum production, wherein crude oil is shipped or piped to an established refining and distribution center, oil shale production would have required the vertical integration of resource extraction, processing, and upgrading to a finished product ready for blending and distribution. Recent interests in oil shale look to overcoming the past technical challenges associated with mining by adapting oil field production methods. Unlike conventional crude oil, oil-shale distillates make poor feedstock for gasoline production and thus may be better suited to making distillate-based fuels such as diesel and jet fuel. The cost of producing oil shale remains uncertain, especially when compared with the economic fundamentals of extracting conventional petroleum reserves.

Geology and Production Technology of Oil Shale

Kerogen

The first phase in organic matter's geologic transformation to petroleum is intermediate conversion to kerogen. During this low-temperature transformation — referred to as *diagenesis* — organically bound oxygen, nitrogen, and sulfur are released.⁸ Complete transformation to petroleum occurs during *catagenesis* — the prolonged exposure to temperatures in the range of 122° to 392°F, generally occurring at depths of 4,000 to 9,800 feet. The catalytic properties of the shale binding the kerogen contribute to the transformation. The threshold for intense oil generation begins at 149°F, equivalent to depths of 4,500 feet or more. Temperatures above 392°F mark the *metamorphic* end-state of transformation — ultimate conversion to methane gas and graphite (pure carbon).

Oil shales have not thermally matured beyond the diagenesis stage due to their relatively shallow depth of burial. Some degree of maturation has taken place, but not enough to fully convert the kerogen to petroleum hydrocarbons. The Green River oil shale of Colorado has matured to the stage that heterocyclic (ring-like) hydrocarbons have formed and predominate, with up to 10% normal- and iso-paraffins (the range of hydrocarbons that includes natural gasoline).⁹ In comparison, conventional crude oil may contain as much as 40% natural gasoline. The kerogen's rich hydrogen/carbon ratio (1.6) is a significant factor in terms of yielding high-

⁸ John M. Hunt, *Petroleum Geochemistry and Geology*, W.H. Freeman and Co., 1979.

⁹ C_n is shorthand notation for the number of carbon atoms. John M. Hunt, *Petroleum Geochemistry and Geology*, W.H. Freeman and Co., 1979

quality fuels. Its 1%-3% nitrogen content, however, may be problematic in terms of producing stable fuels (petroleum typically contains less than 0.5% nitrogen), as well as producing environmentally detrimental nitrogen oxides during combustion.¹⁰ To assess kerogen's potential for yielding hydrocarbon-like fuels, the processes of conventional petroleum refining, synthetic fuel production, and oil shale retorting are compared below.

Conventional Refining

A conventional refinery distills crude oil into various fractions, according to boiling point range, before further processing.¹¹ In order of their increasing boiling range and density, the distilled fractions are fuel gases, light and heavy straight-run naphtha (90°-380°F), kerosene (380°-520°F), gas-oil (520°-1,050°F), and residuum (1,050°F+). Gasoline's molecular range is C₅-C₁₀; middle-distillate fuels (kerosene, jet, and diesel) range C₁₁-C₁₈. Crude oil may contain 10%-40% gasoline, and early refineries directly distilled a straight-run gasoline (light naphtha) of low-octane rating.¹² A hypothetical refinery may "crack" a barrel of crude oil into two-thirds gasoline and one-third distillate fuel (kerosene, jet, and diesel), depending on the refinery's configuration, the slate of crude oils refined, and the seasonal product demands of the market.¹³

Just as natural clay catalysts help transform kerogen to petroleum through catagenesis, metallic catalysts help transform complex hydrocarbons to lighter molecular chains in modern refining processes. The *catalytic-cracking* process developed during the World War II era enabled refineries to produce high-octane gasolines needed for the war effort. *Hydrocracking*, which entered commercial operation in 1958, improved on catalytic-cracking by adding hydrogen to convert residuum into high-quality motor gasoline and naphtha-based jet fuel. U.S. refineries rely heavily on *hydroprocessing* to convert low-value gas oils residuum to high-value transportation fuel demanded by the market. Middle-distillate range fuels (diesel and jet) can be blended from a variety of refinery processing streams.¹⁴ To blend jet fuel, refineries use desulfurized straight-run kerosene, kerosene boiling range hydrocarbons from a hydrocracking unit, and light coker gas-oil (cracked residuum). Diesel fuel can be blended from naphtha, kerosene, and light cracked-oils from coker

¹⁰ Exxon Research and Engineering Co., *Fundamental Synthetic Fuel Stability Study, First Annual Report for May 1, 1979 to April 30, 1981*.

¹¹ James H. Gary and Glenn E. Handwerk, *Petroleum Refining, Technology and Economics* 4th ed., 2001. (Hereafter cited as Gary and Handwerk, *Petroleum Refining: Technology and Economics*.)

¹² *Octane* number refers to the gasoline property that reduces detrimental knocking in a spark-ignition engine. In early research, iso-octane (C₈-length branched hydrocarbon molecules) caused the least knock and was rated 100. *Cetane* number refers to a similar property for diesel fuel, for which normal hexadecane (C₁₆H₃₄) is the standard molecule.

¹³ The term "crack spread" refers to the 3-2-1 ratio of crude-gasoline-distillate. The crack spread and the 3-2-1 crack is a hypothetical calculation used by the New York Mercantile Exchange for trading purposes.

¹⁴ Gary and Handwerk, *Petroleum Refining: Technology and Economics*.

and fluid catalytic cracking units. From the standard 42-gallon barrel of crude oil, U.S. refineries may actually produce more than 44 gallons of refined products through the catalytic reaction with hydrogen.¹⁵

From a simple crude distillation unit, a typical U.S. refinery has grown to a complex of 10 to 15 types of processes.¹⁶ The Nelson Complexity Index, a measure of a refinery's complexity, assigns factors to the capacities of various processing units and compares them to the refinery's crude distillation unit capacity. U.S. refineries rank highest in complexity index, averaging 9.5 compared with Europe's at 6.5. The difference in complexity index reflects the 2-times greater catalytic cracking and 1½-times greater reformation capacities of U.S. refineries.¹⁷ Although U.S. refineries have optimized to produce reformulated gasoline, European refineries yield more middle-distillate diesel fuel to meet the greater European demand for that fuel.

Synthetic Fuel Production

Synthetic fuel technology was developed in prewar Germany to address its scarce petroleum resources. An early process developed by Friedrich Bergius used a catalyst to promote the reaction of hydrogen with coal liquids to produce low-quality gasoline. During the 1960s, the Department of the Interior's Office of Coal Research sponsored research to directly liquefy Eastern coal into substitutes for natural gas and oil (synthetic liquid fuels).¹⁸

In a competing process developed by German scientists Fischer and Tropsch, low-temperature catalysts were used to promote hydrogen's reaction with coal gas and produce gasoline. The South African oil company Sasol later developed this technology further. Modern "gas-to-liquids" (GTL) technology based on the Fischer-Tropsch process converts natural gas to liquid fuels.

Essentially, both the Bergius and Fisher-Tropsch synthetic fuel processes build up longer chain hydrocarbons from smaller molecules. This is the opposite of hydrocracking, the refining process that breaks heavier-weight molecular chains and rings into lighter-weight molecules using hydrogen and catalysts.

¹⁵ Hydroprocessing describes all the processes that react hydrocarbons with hydrogen to synthesize high-value fuels. Hydrocracking reduces denser molecular weight hydrocarbons to lower boiling range products (predominantly gasoline). Impurities such as sulfur are removed by hydrotreating. Refineries produce the hydrogen needed for hydrotreating either by steam reformation of methane (liberated during the atmospheric distillation) or from a vendor who similarly converts natural gas (methane) to hydrogen. Alan G. Bridge "Hydrogen Processing," Chapter 14.1, in *Handbook of Petroleum Refining Processes*, 2nd ed., McGraw-Hill, 1996.

¹⁶ Robert E. Maples, *Petroleum Refinery Process Economics*, 2nd ed., Penwell Corp., 2000.

¹⁷ *Ibid.*, Table 4-1.

¹⁸ Cohen, Linda R. and Roger G. Noll, "The Technology Pork Barrel," Chapter 10, in *Synthetics from Coal*, Washington, DC: The Brookings Institution, 1991.

Oil Shale Retorting

Oil derived from shale has been referred to as a synthetic crude oil and thus closely associated with synthetic fuel production. However, the process of retorting shale oil bears more similarities to conventional refining than to synthetic fuel processes. For the purpose of this report, the term *oil-shale distillate* is used to refer to middle-distillate range hydrocarbons produced by retorting oil shale. Two basic retorting processes were developed early on — aboveground retorting and underground, or *in situ*, retorting. The retort is typically a large cylindrical vessel, and early retorts were based on rotary kiln ovens used in cement manufacturing. In situ technology involves mining an underground chamber that functions as a retort. A number of design concepts were tested from the 1960s through the 1980s.

Retorting essentially involves destructive distillation (*pyrolysis*) of oil shale in the absence of oxygen. Pyrolysis (temperatures above 900°F) thermally breaks down (*cracks*) the kerogen to release the hydrocarbons and then cracks the hydrocarbons into lower-weight hydrocarbon molecules. Conventional refining uses a similar thermal cracking process, termed *coking*, to break down high-molecular weight residuum.

OTA compiled properties of oil-shale distillates produced by various retorting processes (**Table 1**). In general, oil-shale distillates have a much higher concentration of high boiling-point compounds that would favor production of middle-distillates (such as diesel and jet fuels) rather than naphtha.¹⁹ Oil-shale distillates also had a higher content of olefins, oxygen, and nitrogen than crude oil, as well as higher pour points and viscosities. Above-ground retorting processes tended to yield a lower API gravity oil than the in situ processes (a 25° API gravity was the highest produced).²⁰ Additional processing equivalent to hydrocracking would be required to convert oil-shale distillates to a lighter range hydrocarbon (gasoline). Removal of sulfur and nitrogen would, however, require hydrotreating.

By comparison, a typical 35° API-gravity crude oil may be composed of up to 50% of gasoline and middle-distillate range hydrocarbons. West Texas Intermediate crude (a benchmark crude for trade in the commodity futures market) has a 0.3% sulfur content, and Alaska North Slope crude has a 1.1% sulfur content.²¹ The New York Mercantile Exchange (NYMEX) specifications for light “sweet” crude limits sulfur content to 0.42% or less (A.S.T.M. Standard D-4294) and an API gravity between 37 and 42 degrees (A.S.T.M. Standard D-287).²²

¹⁹ OTA, Ch. 5 — Technology, p. 157.

²⁰ API gravity refers to the American Petroleum Institute measure of crude oil density — the higher the API gravity, the lighter the crude oil’s density. Light crudes exceed 38° API, intermediate crudes range 22° to 38° API, and heavy crudes fall below 22° API.

²¹ Platt’s *Oil Guide to Specifications*, 1999 [<http://www.emis.platts.com/thezone/guides/platts/oil/crudeoilspecs.html>], viewed Apr. 5, 2006.

²² New York Mercantile Exchange, *Exchange Rulebook*, Light “Sweet” Crude Oil Futures Contract, at [http://www.nymex.com/rule_main.aspx], visited Aug. 25, 2005.

Oil-shale distillate has been considered a synthetic substitute for crude oil; however, its fungibility may be limited in modern refining operations. Because the *kerogen* contained by the shale is only a petroleum precursor, it lacks the full range of hydrocarbons used by refineries in maximizing gasoline production. Also, because of technology limitations, only hydrocarbons in the range of middle-distillates (kerosene, jet fuel, diesel fuel) appear extractable.

Table 1. Properties of Oil-Shale Distillates Compared with Benchmark Crude Oils

	° API	% Sulfur
OTA Reported Oil-Shale Distillates Properties ^a	19.4-28.4	0.59-0.92
Shell ICP Oil-Shale Distillate ^b	34	0.8
Oil Tech Oil-Shale Distillate ^c	30	no report
West Texas Intermediate Crude Oil ^d	40	0.30
NYMEX Deliverable Grade Sweet Crude Oil Specification ^e	37-42	<0.42
Alaska North Slope Crude Oil ^d	29-29.5	1.10

a. OTA, *An Assessment of Oil Shale Technologies*, Table 19, 1980.

b. Energy Washington Week, "Shell Successfully Tests Pilot of New In Situ Oil Shale Technology," Oct. 12, 2005.

c. Jack Savage, Testimony Before the Subcommittee on Energy and Mineral Resources, June 23, 2005.

d. *Platt's Oil Guide to Specifications*, 1999.

e. NYMEX, *Exchange Rulebook*, Light "Sweet" Crude Oil Futures Contract.

Both in situ and above-ground retorting processes have been plagued with technical and environmental problems. Apart from the problem of sustaining controlled combustion underground, in situ retorting suffered from the environmental drawback of causing groundwater contamination. Above-ground retorting required underground or open-pit mining to excavate the shale first. While either mining method is well-practiced, the expended shale that remained after retorting presented a disposal problem, not to mention the overburden rock that had to be removed in the case of open-pit mining. Above-ground retorts also faced frequent problems from caked-up shale, which led them to shut down. Some recent approaches have aimed to avoid these drawbacks altogether.

Shell In Situ Conversion Process. For the past five years, the Shell Exploration and Production Company has been conducting research into directly extracting oil-shale distillates on its 20,000-acre Cathedral Bluffs property near Parachute (Rio Blanco County), Colorado.²³ Unlike previously attempted in situ

²³ Testimony of Stephen Mut, Shell Unconventional Resources Energy Oil, *Shale and Oil Sands Resources Hearing*, Senate Energy and Natural Resources Committee, Tuesday, Apr. (continued...)

retorting, Shell's *in situ conversion process* (ICP) involves drilling holes up to 2,000 feet deep, inserting electrical resistance heaters, and heating the shale to 650-700°F over a period of months. The ICP converts the kerogen to gas and petroleum-like liquids. The process not only consumes high amounts of energy to operate the heaters, it also requires freezing the perimeter of the production zone to restrict groundwater flow. Shell Oil Company reports extracting a 34°API product consisting of 1/3 gas (propane and butane) and 2/3 liquids split 30% naphtha, 30% jet fuel, 30% diesel, and 10% slightly heavier oil. Sulfur content was 0.8% by weight.

Oil Tech Above-Ground Retorting. Oil Tech, Inc., has been developing a new above-ground retort, which it reports as having the capacity of extracting one barrel of shale-oil per ton of shale per hour.²⁴ The company has reported producing a low-sulfur 30° API-gravity oil consisting of 10% naphtha, 40% kerosene, 40% diesel, and 10% heavy residual oil. Starting off where past retorting attempts ended, Oil Tech intends to use previously mined oil shale that had been stockpiled.

History of Oil Shale Development

Oil shale was originally considered as a reserve supply of crude oil to fuel U.S. naval vessels in times of short supply or emergencies. Because the largest oil shale resources reside on federal lands, the federal government historically has had a direct interest and role in encouraging the development of this resource. Potential oil-bearing lands in California and Wyoming were first set aside for withdrawal as sources of fuel for the Navy under the Pickett Act of 1910. Later, presidential executive orders created NOSR Nos. 1 and 3 in Colorado and NOSR No. 2 in Utah.

Early Synthetic Liquid Fuels Efforts

During World War II, Congress's concern for conserving and increasing the nation's oil resources prompted passage of the Synthetic Liquid Fuels Act of 1944 (30 U.S.C. Secs. 321 to 325), which authorized funds for the Interior Department's Bureau of Mines to construct and operate demonstration plants to produce synthetic liquid fuel from oil shales, among other substances.

Congress passed the Defense Production Act of 1950 (Ch. 932, 64 Stat. 798) during the Korean War to develop and maintain whatever military and economic strength was necessary to support collective action through the United Nations. The Title III program authorized governmental requisition of property for national defense and expansion of productive capacity, among other authorities. Between 1949 and 1955, the U.S. Bureau of Mines received \$18 million to operate three above-ground gas combustion retorts at Anvil Points, Colorado, the site of NOSR No. 1.

²³ (...continued)
12, 2005.

²⁴ Jack S. Savage, Oil Tech, Inc., Testimony before the *Hearing on The Vast North American Resource Potential of Oil Shale, Oil Sands, and Heavy Oils — Part 1*, House Subcommittee on Energy and Mineral Resources, June 23, 2005.

Long before the United States' increasing dependence on imported crude oil become apparent, oil shale began attracting the interest of some major petroleum companies: Exxon, Occidental Petroleum, and Union Oil, among others. In 1961, the Union Oil Company began testing its "Union A" retort at Parachute Creek, Colorado. Though producing 800 barrels per day (bpd), Union shut the retort down after 18 months due to cost. In 1964, The Oil Shale Company (Tosco), Standard Oil of Ohio (Sohio), and Cleveland Cliffs Mining formed a consortium to operate the Colony Oil Shale mine. Despite producing 270,000 barrels, Tosco shut down production in 1972. Occidental Petroleum also began oil shale retorting experiments in 1972 near Rifle, Colorado, and ultimately evaluated six retorts.

Defense Department Programs

The Defense Department had become interested in oil shale as an alternative resource for producing quality jet fuel as early as 1951.²⁵ The U.S. Navy and the Naval Petroleum and Oil Shale Reserves Office (NPSRO) started large-scale evaluations of oil shale's suitability for military fuels in the early 1970s. Tosco was contracted to produce and process 10,000 barrels of oil-shale distillates. Development Engineering, Inc., leased the federal Anvil Points site (Naval Oil Shale Reserve 3) in 1972 and formed the Paraho Development Corporation in 1973 (a consortium of 17 energy companies). Paraho's plans included a five-year program to develop two pilot scale retorts and produce oil-shale distillates for the Navy fuel testing. Paraho initially produced 10,000 barrels of oil-shale distillates that Sohio processed into gasoline, JP-4 and JP-5 jet fuel, diesel fuel marine (DFM), and a heavy fuel oil at the Gary Western Refinery in Fruita, Colorado. Though the fuels produced were off-specification, analysis indicated that the refining process could be optimized to produce specification fuels. Paraho was awarded a follow-on contract to produce 100,000 barrels of oil-shale distillates for processing specification fuels in Sohio's Toledo Refinery. The Navy conducted extensive tests with the fuels in military and commercial equipment.

In the late 1970s, the Air Force became interested in evaluating oil shale's suitability for producing JP-4 jet fuel. Under Project Rivet Shale, in 1979, the Air Force awarded contracts to Ashland Research and Development, Suntech, Inc., and UOP, Inc., to develop technology to produce oil shale-derived JP-4 jet fuel. In 1982, over 10,000 gallons of JP-4 were processed at the Caribou Four Corners Refinery in Woods Cross, Utah, from crude oil-shale distillates produced by Geokinetics. JP-4 specification fuel was produced from other oil shale retorting techniques pioneered by Occidental, Paraho, and Union Oil. Unocal (formerly Union Oil Company) operated the Parachute Creek oil shale plant and reportedly produced 4.6 million barrels of oil-shale distillates from 1985 to 1990 for Air Force evaluation under Project Rivet Shale.²⁶ The Air Force generally phased out JP-4 in the early 1990s in favor of kerosene-based JP-8.

²⁵ Personal communication with William E. Harrison III, Office of Deputy Under Secretary of Defense for Advanced Systems and Concepts, Oct. 25, 2005.

²⁶ The Center for Land Use Integration, *Unocal Oil Shale Plant*, at [<http://ludb.clui.org/ex/i/CO3191/>], visited Mar. 28, 2006.

Department of Energy Synthetic Fuels Program

The Department of Energy (DOE) encouraged interest in large-scale oil shale development through its Synthetic Fuels Program. DOE initially promoted two prototype lease tracts in the Piceance Basin of Rio Blanco County, Colorado (NOSR tracts C-a and C-b).²⁷ Amoco later produced 1,900 barrels using in situ retorting in tract C-a, and Occidental Petroleum planned a similar effort for tract C-b.

The Interior Department Appropriations Act (P.L. 96-126) and the Supplemental Appropriations Act of 1980 (P.L. 96-304) appropriated \$17.522 billion to the Energy Security Reserve fund in the Treasury Department. Of that amount, \$2.616 billion was committed by the Department of Energy to three synthetic fuels projects. Two of the projects were approved under the Defense Production Act: Union Oil Company's Parachute Creek project in Garfield County, Colorado, and Exxon-Tosco's Colony oil shale project, also in Garfield County. Union Oil Company received a \$0.4 billion price guarantee for the Parachute Creek Shale Oil Project, and the Exxon-Tosco Colony Oil Shale Project received a loan guarantee of \$1.15 billion (applied to the 40% owned by Tosco).²⁸ Union Oil was expected to produce 10,400 bpd at \$42.50/bbl, which, adjusted for inflation, equaled \$51.20/bbl by March 1, 1985.

As an additional stimulus to producing alternative fuels — for which oil shale, among others, qualified — Congress provided a \$3.00 /bbl production tax credit provision in the Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223). The credit would take full effect when crude oil prices fell below \$23.50 /bbl (in 1979 dollars) and would gradually phase out as prices rose above to \$29.50/bbl.

Tosco's interest in the Colony project was sold in 1979, and again in 1980, to Exxon Company for the Colony II development. Exxon planned to invest up to \$5 billion in a planned 47,000 bpd plant using a Tosco retort design. After spending more than \$1 billion, Exxon announced on May 2, 1982, that it was closing the project and laying off 2,200 workers.

U.S. Synthetic Fuels Corporation

The Energy Security Act of 1980 (P.L. 96-294, Title I, Part B) established the United States Synthetic Fuels Corporation (SFC) with the authority to provide financial assistance to qualified projects that produced synthetic fuel from coal, oil shale, tar sands, and heavy oils. The SFC's loan commitments would be paid from the Energy Security Reserve fund. Executive Order 12346 (Synthetic Fuels) later provided for an orderly transition of DOE's earlier synthetic fuel program to the SFC.

²⁷ Garfield County, Colorado, *Garfield County Comprehensive Plan Revision, Study Area Five*, adopted version, Apr. 24, 2002, at [<http://garfield-county.com/home/index.asp?page=664>], visited Mar. 28, 2006.

²⁸ H.Rept. 99-196, Part 1, July 11, 1985.

Between 1981 and 1984, the SFC received 34 proposals for oil shale projects in three rounds of solicitations. Only three letters of intent were ever issued. Union Oil's Parachute Creek Phase II 80,000 bpd plant was to receive a \$2.7 billion funding commitment and a guarantee of \$60/bbl, escalated up to \$67 /bbl; another \$0.5 billion in price and loan guarantees was added in October 1985 to Union's Parachute Creek Phase I. Cathedral Bluffs, a 14,300 bpd plant based on a Union Oil design, was to receive a \$2.19 billion loan guarantee and a \$60/bbl price guarantee. Seep Ridge Oil Shale's 1,000 bpd plant was to receive \$45 million in price and loan guarantees. None of the oil shale projects that received SFC loan guarantees ever received actual funding, as Congress rescinded \$2 billion originally appropriated for the Energy Security Reserve fund in the Deficit Reduction Act of 1984 (P.L. 98-369) and later abolished the SFC.

In 1984, Congress asked the General Accounting Office (GAO) to report on the progress of synthetic fuels development and to specifically respond to the question "Why have project sponsors dropped synthetic fuels projects?" GAO answered that oil had become plentiful, with about 8 to 10 million barrels per day in excess worldwide capacity, and the trend in rising oil prices had reversed after early 1981.

President Reagan's Executive Order 12287 had removed price and allocation controls on crude oil and refined petroleum products in 1981. For the first time since the early 1970s, market forces replaced regulatory programs and domestic crude oil prices were allowed to rise to a market-clearing level. Decontrol also set the stage for the relaxation of export restrictions on refined petroleum products. Oil demand had also declined, due in part to energy conservation measures and a worldwide economic recession. A more fundamental change had taken place in the way that oil commodities were traded. Prior to 1980, the price of crude oil was determined by long-term contracts, with 10% or so of internationally traded oil exchanged on the spot market.²⁹ By the end of 1982, more than half of the internationally traded oil was exchanged on the spot market or tied to the spot market price. The most significant change occurred in 1983, with the introduction of crude oil futures by the New York Mercantile Exchange (NYMEX). All served to undermine price setting by the Organization of Petroleum Exporting Countries (OPEC).

Tax incentives for oil shale projects had also been reduced. Some of the generous oil depreciation allowances under the 1981 Economic Recovery Tax Act (P.L. 97-48) were rescinded in 1982 by the Tax Equity and Fiscal Responsibility Act (P.L. 97-248), reducing potential project sponsors' after-tax rates of return.

The House began considering a bill to abolish the SFC in 1985, and Congress terminated the Corporation the following year under the Consolidated Omnibus Budget Reconciliation Act of 1985 (P.L. 99-272). The **Appendix** to this report provides a more complete legislative history of the Synthetic Fuels program.

²⁹ Daniel Yergin, *The Prize*, Touchstone, 1991, pp. 722-725.

Renewed Interest in Oil Shale

In 2005, Congress conducted hearings on oil shale to discuss opportunities for advancing technology that would facilitate “environmentally friendly” development of oil shale and oil sands resources.³⁰ The hearings also addressed legislative and administrative actions necessary to provide incentives for industry investment, as well as exploring concerns and experiences of other governments and organizations and the interests of industry. The Energy Policy Act of 2005 included provisions under Section 369 (Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels³¹) that direct the Secretary of the Interior to begin leasing oil shale tracts on public lands and to cooperate with the Secretary of Defense in developing a program to commercially develop oil shale, among other strategic unconventional fuels.

The Bureau of Land Management (BLM) established the Oil Shale Task Force in 2005 to address oil shale access on public lands and impediments to oil shale development on public lands. Title 30, Section 241(a) of the Mineral Lands Leasing Act formerly restricted leases to 5,120 acres. Advocates of oil shale development claimed that restrictions on lease size hindered economic development. The Energy Policy Act amended Section 241(a) by raising the lease size to 5,760 acres and restricting total lease holdings to no more than 50,000 acres in any one state.³²

On September 20, 2005, the Bureau of Land Management announced it had received 19 nominations for 160-acre parcels of public land to be leased in Colorado, Utah, and Wyoming for oil shale research, development, and demonstration (RD&D). On January 17, 2006, BLM announced that it accepted eight proposals from six companies to develop oil shale technologies; the companies selected were Chevron Shale Oil Co., EGL Resources Inc., ExxonMobil Corp., Oil-Tech Exploration LLC, and Shell Frontier Oil & Gas.³³ Six of the proposals will look at in situ extraction to minimize surface disturbance. Each proposal will be evaluated under the National Environmental Policy Act (NEPA). In addition to the 160 acres allowed in the call for RD&D proposals, a contiguous area of 4,960 acres is reserved for the preferential right for each project sponsor to convert to a future commercial lease after additional BLM reviews.

The Energy Policy Act also identified oil shale as a strategically important domestic resource and directed DOE to coordinate and accelerate its commercial development. Section 369(q) (Procurement of Unconventional Fuels by the

³⁰ The Senate Energy and Natural Resources Committee, *Oversight Hearing on Oil Shale Development Effort*, Apr. 12, 2005.

³¹ Also cited as the Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005.

³² 30 USC 241 (4) “For the privilege of mining, extracting, and disposing of oil or other minerals covered by a lease under this section ... no one person, association, or corporation shall acquire or hold more than 50,000 acres of oil shale leases in any one State.”

³³ Bureau of Land Management, *BLM Announces Results of Review of Oil Shale Research Nominations*, Jan. 17, 2006, at [http://www.blm.gov/nhp/news/releases/pages/2006/pr060117_oilshale.htm], visited Mar. 29, 2006.

Department of Defense) of the act directs the Secretaries of Defense and Energy to develop a strategy to use fuel produced from oil shale to help meet the fuel requirements of the Defense Department when the Defense Secretary determines that doing so is in the national interest. The Defense Department had worked jointly with Energy on a Clean Fuels Initiative to develop, test, certify, and use zero-sulfur jet fuels from alternative resources (oil shale, among others). By eliminating sulfur, the fuels would be suitable for use in fuel cells to generate electricity and in turbine engines used in aircraft and ground vehicles. A synthetic fuel process based on Fischer-Tropsch had been considered. At the time of the President's FY2007 budget request, DOE proposed terminating oil technology research, and the Defense Department left Clean Fuels unfunded.³⁴

Since 1910, several legislation-based initiatives have attempted to promote oil shale development. (Legislation establishing the oil shale reserves and related federal programs is summarized in the **Appendix** of this report.) However, more recent regulatory policies (see below) appear adverse to oil shale development, at least to the wider use of middle-distillate fuels producible from oil shale.

Incentives and Disincentives to Development

The economic incentive for producing oil shale has long been tied to the price of crude oil. The highest price that crude oil ever reached — \$87/bbl (2005 dollars) — occurred in January 1981 (**Figure 2**).³⁵ Exxon's decision to cancel its Colony oil shale project came a year and half later, after prices began to decline and newly discovered, less-costly-to-produce reserves came online. The price of crude oil spiked to nearly \$70/bbl after Hurricanes Katrina and Rita, and the recent climb to above \$67 /bbl has led to some speculation that prices may remain high indefinitely. In the Energy Information Administration's (EIA's) reference case projection, though, "the average world crude oil price continues to rise through 2006 and then declines to \$46.90/bbl in 2014 (2004 dollars) as new supplies enter the market. It then rises slowly to \$54.08/bbl in 2025."³⁶ Near-record gasoline prices have led to similar speculation, as the average price of gasoline has stayed consistently above \$2 per gallon since May of 2005, and the on-highway diesel price has stayed even higher.³⁷ However, oil company investment decisions may be more conservatively based on making profits at the \$20-\$30/barrel range of just a few years ago than on projected prices. That is, high prices may not be enough of an incentive for risky developments in conventional oil, let alone oil shale.

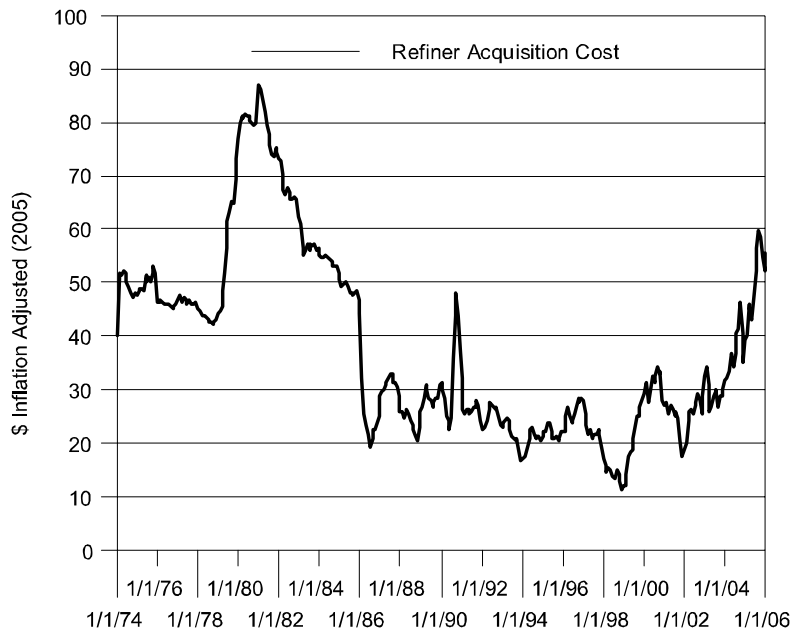
³⁴ Personal communication with Dr. Theodore K. Barna, Feb. 8, 2006.

³⁵ U.S. DOE EIA, *Imported Crude Oil Prices: Nominal and Real*, at [<http://www.eia.doe.gov/emeu/steo/pub/fsheets/petroleumprices.xls>], visited Apr. 5, 2006.

³⁶ U.S. DOE EIA, *Annual Energy Outlook 2006 with Projections to 2030 (Early Release) — Overview*, December 2005, at [<http://www.eia.doe.gov/oiaf/aeo/key.html>], visited Apr. 5, 2006.

³⁷ U.S. DOE EIA, *Gasoline and Diesel Fuel Update*, at [<http://tonto.eia.doe.gov/oog/info/gdu/gasdiesel.asp>], visited Apr. 5, 2006.

Figure 2. Refiner Acquisition Cost of Imported Crude Oil



Source: U.S. DOE EIA, *World Oil Market and Oil Price Chronologies 1970-2004*, Mar. 2005, at [<http://www.eia.doe.gov/cabs/chron.html>]; EIA Refiner Acquisition Cost of Crude Oil (for July 2005 to Jan. 2006), at [http://tonto.eia.doe.gov/dnav/pet/pet_pri_rac2_dcu_nus_m.htm].

Crude oil production costs vary widely by geography and reservoir conditions, and they may be more important factors now than 25 years ago as aging reservoirs decline in production. Production involves lifting the oil to the surface and the gathering, treating, and field processing and storage of the oil. The cost of production, sometimes referred to as *lifting cost*, includes labor to operate the wells and related equipment; repair and maintenance of the wells and equipment; and materials, supplies, and energy required to operate the wells and related equipment. In the Persian Gulf region, where a single well may produce thousands of barrels per day, production costs may be as little as a few dollars per barrel. Production costs in the United States had approached \$15/bbl by 2004.³⁸ ExxonMobile reported production costs increases from \$4½ to \$5½ /bbl for its U.S. operations over the past several years.³⁹ In older, far less productive wells in the United States, production costs may reach more than \$25/bbl.⁴⁰

In 1998, a supply glut forced the price of crude oil down to almost \$10/barrel and gasoline sold for less than \$0.80/gallon in some markets. Some domestic producers charged, in a U.S. Court of International Trade suit, that oil imports had

³⁸ U.S. DOE EIA, *Performance Profiles of Major Energy Producers 2004*, Table 11, Income Components and Financial Ratios in Oil and Natural Gas Production for FRS Companies, 2003 and 2004, at [<http://www.eia.doe.gov/emeu/perfpro/>], visited Apr. 12, 2006.

³⁹ Exxon Mobile Corp, *Form 10-K*, Average sales prices and production costs per unit of production — consolidated subsidiaries Feb. 28, 2006.

⁴⁰ Thomas R. Stauffer, "Trends In Oil Production Costs In The Middle East, Elsewhere," *Oil & Gas Journal*, Mar. 21, 1994.

been dumped on the American market.⁴¹ Though unsuccessful, the suit does say something further about bottom-line production costs (the crude oil price equivalent that producers could not compete below) and the production costs that oil shale may need to compete against. For several years preceding the price drop, crude oil ranged from \$20 to \$30/bbl.

The perception that oil shale serves as a crude oil substitute overlooks the limited fungibility of the middle distillates that are extractable — they make poor feedstock for gasoline production. That does not necessarily prevent oil-shale distillates from being used as gasoline feedstock, but additional energy and hydrogen are needed to crack them. The loss may be even greater considering the lower fuel efficiency of spark-ignition engines that use gasoline, compared with compression ignition engines that use diesel distillate fuels.

Other incentives or disincentives may include the cost and size of an oil shale processing facility, conventional refining profitability, and the cost and availability of refined commodities. Certain environmental and tax regulations that act as incentives to using gasoline in light-duty vehicles discourage middle-distillate diesel fuel use, and thus oil-shale distillates as substitute motor fuels.

The Cost of Constructing an Oil Shale Facility

A reliable cost estimate for producing oil shale has proved challenging, if not controversial. The cost of resources extraction had depended on whether conventional underground or strip-mining methods were employed. Because there was a considerable experience in mining, reliable cost estimates could be developed. A second variable — the cost of constructing and operating an oil shale facility — had to be accounted for separately. The former OTA estimated in 1979 that a 50,000 bpd oil shale facility (based on above-ground retorting technology) would have required an investment of \$1.5 billion and operating costs of \$8 to \$13/bbl. Using the Nelson-Farrar Cost Indexes to adjust refinery construction and operation costs to 2004 dollars, the investment would be equivalent to \$3.5 billion, with operating costs of \$13 to \$21/bbl.⁴² This excludes the cost of shale extraction.

In comparison, the cost of building a new conventional refinery has been estimated to range between \$2 and \$4 billion as recently as 2001.⁴³ The cost of operating a refinery (marketing, energy, and other costs) averaged nearly \$6/bbl during 2003-2004, as reflected in the difference between gross and net margins (where the gross margin reflects the refiner's revenue minus the cost of crude oil).⁴⁴

⁴¹ "U.S. Oil Dumping Case Wins Investigation By Commerce," *Oil & Gas Journal*, Oct. 2, 2000.

⁴² *1980 vs. 2004 Refinery Inflation Index* and *1980 vs. 2004 Refinery Operating Index* from the Nelson-Farrar Cost Indexes, *Oil & Gas Journal* (published first issue each month).

⁴³ "U.S. appears to have built last refinery," *Alexander's Gas & Oil Connections*, vol. 6, issue 13, Jul. 17, 2001.

⁴⁴ U.S. DOE EIA, *Performance Profiles of Major Energy Producers 2004*, Table 15, U.S. (continued...)

An oil shale facility may not be directly comparable to a refinery in terms of construction costs, though some processes, such as hydrotreating, may be common to both. If oil field-based technologies such as Shell's proposed ICP are successfully adapted to resource extraction, facility costs could be reduced, but operating costs could increase given the energy-intensive aspect of the technology.

Under the U.S. Air Force Project Rivet Shale, Union Oil's Parachute Creek Phase I project produced 4.6 million barrels of oil-shale distillates from 1985 to 1990 at a cost of \$650 million; roughly the equivalent of \$141/bbl, or \$3.52/gal. (wholesale). Since Rivet Shale produced a jet fuel equivalent, a comparison might be made with the price of jet fuel at the time. In comparison, a refiner's crude oil acquisition costs ranged from a less \$15/bbl to \$27/bbl in nominal dollars over that same time period.⁴⁵ The spot market price for kerosene-based jet fuel rose from less than \$0.40/gal in 1985 to more than \$1.10/gal by 1990.

The Rand Corporation recently estimated that a "first-of-kind" surface retort facility might cost \$5-\$7 billion, with operating costs of \$17 to \$23/bbl in 2005 dollars. Rand projects that a crude oil equivalent of West Texas Intermediate would need to be at least \$70 to \$95/bbl for such an operation to be profitable.⁴⁶ Shell Oil believes that in situ conversion can be profitable, producing oil-shale distillates at \$25/bbl once steady-state production is reached.⁴⁷ The disparity in estimates demonstrates the controversy over the issue. It should be noted that Rand refers to the older retorting technology that relied on mining methods for resource extraction, whereas Shell's estimate is based on oil field-based technology for resource extraction.

The Ideal Size for an Oil Shale Facility

As domestic crude oil production declined through the 1970s, many marginally profitable and often smaller refineries were closed or idled.⁴⁸ Of the 324 refineries operating 1981, 142 refineries currently remain operating. However, they represent a crude distillation capacity of approximately 17.5 million bpd, compared with 14.5 million bpd in the mid 1980s, and range in size from 557,000 bpd (ExxonMobile's Baytown, Texas refinery) to 1,707 bpd (Foreland Refining Corp's refinery in Eagle

⁴⁴ (...continued)

Refined Product Margins and Costs per Barrel Sold and Product Sales Volume for FRS Companies, 2003-2004, at [<http://www.eia.doe.gov/emeu/perfpro/>], visited Apr. 12, 2006.

⁴⁵ U.S. DOE EIA, *Crude Oil Refiner Acquisitions Costs*, Table 5.21, 1968-2004, at [<http://www.eia.doe.gov/emeu/aer/txt/ptb0521.html>], visited Feb. 21, 2006.

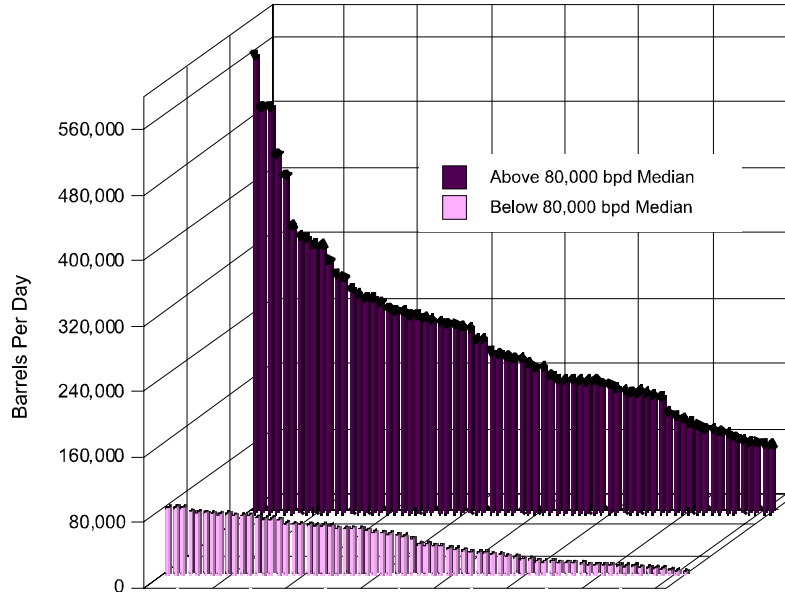
⁴⁶ Bartis, James, T., et al., *Oil Shale Development in the United States*, The Rand Corporation, 2005.

⁴⁷ "Is Oil Shale America's Answer to Peak-Oil Challenge?" *Oil & Gas Journal*, Aug. 9, 2004.

⁴⁸ The last new U.S. refinery was built in 1976 by Marathon Ashland in Garyville, Louisiana. U.S. DOE EIA, *Country Analysis Briefs — United States of America January, 2005*, at [<http://www.eia.doe.gov/emeu/cabs/usa.html>], visited Apr. 5, 2006.

Springs, Nevada).⁴⁹ The median capacity (half above and half below) of all operating refineries is approximately 80,000 bpd (**Figure 3**). The 71 refineries above the median capacity are responsible for 85% of the current overall U.S. production (14.8 million bpd). The trend toward larger refineries reflects the economic efficiency gained by increased scale. (For further information on refining, refer to CRS Report RL32248, *Petroleum Refining: Economic Performance and Challenges for the Future*, by Robert L. Pirog.)

Figure 3. Refinery Capacity Distribution Above and Below Median 80,000 BPD Size



Source: EIA Annual Energy Outlook, Table 38, Capacity of Operable Petroleum Refineries by State, 2005.

OTA's reference case 50,000 bpd oil shale facility would have been typical for refinery capacities in the late 1970s, but compared with current capacities, it might appear undersized. However, in terms of matching middle-distillate output, an oil shale facility requires $\frac{1}{3}$ the capacity of a conventional refinery. Since U.S. refineries yield at most 47% motor gasoline vs. 33% middle-distillates, a 50,000 bpd oil shale facility today (producing middle distillates exclusively) would match the distillate output of a 150,000 bpd conventional refinery.⁵⁰ This suggests that relatively smaller oil shale production facilities could be as effective as a larger conventional refinery when it comes to producing middle distillates.

The complicated permitting process has been an argument against building a new refinery and for expanding an existing refinery's capacity instead. The approval

⁴⁹ U.S. DOE EIA, *Refinery Utilization and Capacity*, at [http://tonto.eia.doe.gov/dnav/pet/pet_pnp_top.asp], visited Feb. 22, 2006.

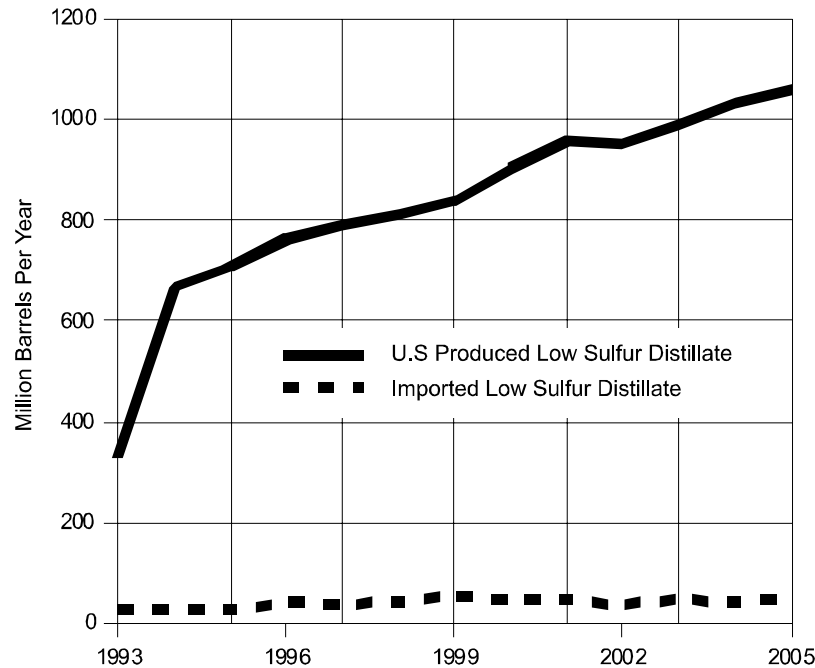
⁵⁰ U.S. DOE EIA, *Petroleum Supply Annual 2004*, vol. 1, Table 19, Percent Refinery Yield of Petroleum Products by PAD and Refining Districts, 2004, at [http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volum_e1.html], visited Apr. 5, 2006.

process for new refinery construction has been estimated to require up to 800 different permits.⁵¹ An oil shale facility's considerably less complexity would appear to have an inherent advantage over a conventional refinery when it comes to permitting. Congress recognized that increasing petroleum refining capacity serves the national interest and included provisions in the Energy Policy Act of 2005 (Title III, Subtitle H—Refinery Revitalization) to streamline the environmental permitting process. A refiner can now submit a consolidated application for all permits required by the Environmental Protection Agency (EPA). To further speed the permit's review, the EPA is authorized to coordinate with other federal agencies, enter into agreements with states on the conditions of the review process, and provide states with financial aid to hire expert assistance in reviewing the permits. Additional provisions under Title XVII (Incentives for Innovative Technologies) of the act guarantee loans for refineries that avoid, reduce, or sequester air pollutants and greenhouse gases if they employ new or significantly improved technology. Permitting would be a secondary consideration for new construction, if refining was an unfavorable investment.

Competing with Imported Distillates

Between 1993 and 2005, low-sulfur middle distillate production in the United States tripled from 328 million barrels to 1,058 million barrels, but some imports were still needed to satisfy demand (**Figure 4**). The current 55 million barrels per year of imports is the equivalent of 150,000 bpd in production, or three oil shale plants on the scale of OTA's reference case 50,000 bpd facility.

⁵¹ "Crude Awakening," *Investor's Business Daily*, Mar. 28, 2005.

Figure 4. Imported Crude Oil and Refined Products

Source: EIA Petroleum Navigator, U.S. Refinery Production of Distillates 15-500 ppm Sulfur, and U.S. Distillates 15-500 ppm Sulfur Imports, at [<http://tonto.eia.doe.gov/dnav/pet/hist>].

Like U.S. refineries, European refineries also began to optimize for gasoline production in the early 1990s, only to see the European demand shift toward middle-distillate diesel fuel due largely to European tax incentives (discussed below) that favor diesel fuel use. Excess gasoline now produced by these refineries is exported to the U.S. market. Diesel fuel is forecast to make up 68% percent of European consumption by 2010.⁵² How European refineries respond to an increased diesel fuel demand will likely affect gasoline exports to the United States, particularly if the refineries shift their optimization more toward diesel than investing capital in additional diesel capacity. Both diesel and gasoline exports to the U.S. market could be reduced. U.S. refineries appear to have little excess capacity to make up both the gasoline and diesel loss, leaving some opportunity for oil shale to make up the distillate loss.

Assuming that U.S. refineries yield $\frac{1}{3}$ middle-distillates, actual refining capacity on the order of 1 million bpd would have been required. In terms of oil shale production, three 50,000-bpd plants processing 1,867 million tons of oil shale (yielding 15 to 30 gallons per ton) could be required to fill the possible gap in domestic supply.

⁵² Energy Intelligence Group, "European Refiners Need to Bite Bullet of Downstream Investment," Mar. 14, 2005, at [<http://www.energyintel.com/>].

Regulatory Disincentives

Apart from economic reasons, some regulatory policies may discourage the production and use of oil-shale distillate fuels. Both gasoline and diesel fuel are subject to Clean Air Act regulations and federal motor fuel taxes. Both regulations and taxes are more lenient towards gasoline use. In comparison, European Union (EU) environmental standards and tax regulations are more lenient towards diesel fuel and consequently have stimulated its broader consumption. Since oil-shale distillates could substitute for diesel fuel, any regulatory bias toward gasoline could act as a disincentive to oil shale production.

Diesel Vehicle Demand. Passenger vehicles and light-duty trucks (under 8,500 lbs. gross vehicle weight) create the primary demand for transportation fuel in the United States. However, nearly 22% of the transportation fuel demand is for diesel, primarily in heavy-duty on- and off-road vehicles (semi-tractor trucks, earthmoving equipment, and railroad locomotives). Light-duty diesel trucks and passenger vehicles make up a smaller (but uncertain) percentage of the diesel demand, based on the lower number of miles private vehicles drive annually compared with commercial vehicles. Light-duty vehicles do, however, make up slightly more than half of the on-road diesel vehicles sold. Though overall, light-duty diesel vehicles have made up only 5% of the total light-duty vehicles sold recently (~349,000 light-duty diesel trucks and ~30,000 diesel passenger vehicles versus 16.9 million total light-duty vehicles sold in 2004).⁵³ The EIA sees a slower growth of light-duty diesel vehicles in the United States than in Europe.⁵⁴ In contrast to U.S. sales of light-duty diesel vehicles, new diesel passenger vehicle registration in Europe rose from 22.3% in 1998 to 48.25% in 2004.⁵⁵ The effect of increased diesel registration can be seen in the increased refinery output and net deliveries of diesel reported for European members of the Organization of Economic Co-operation and Development (OECD) by the International Energy Agency (IEA).⁵⁶ (See **Figure 5.**)

Assuming that a separate diesel fuel for light-duty diesel vehicles will not be created, the EIA projects that U.S. refiners are unlikely to see the impact of a developing light-duty diesel vehicle market in the next decade. Given EIA's projection, the opportunity for oil-shale distillates as diesel substitutes would appear similarly limited in the United States.

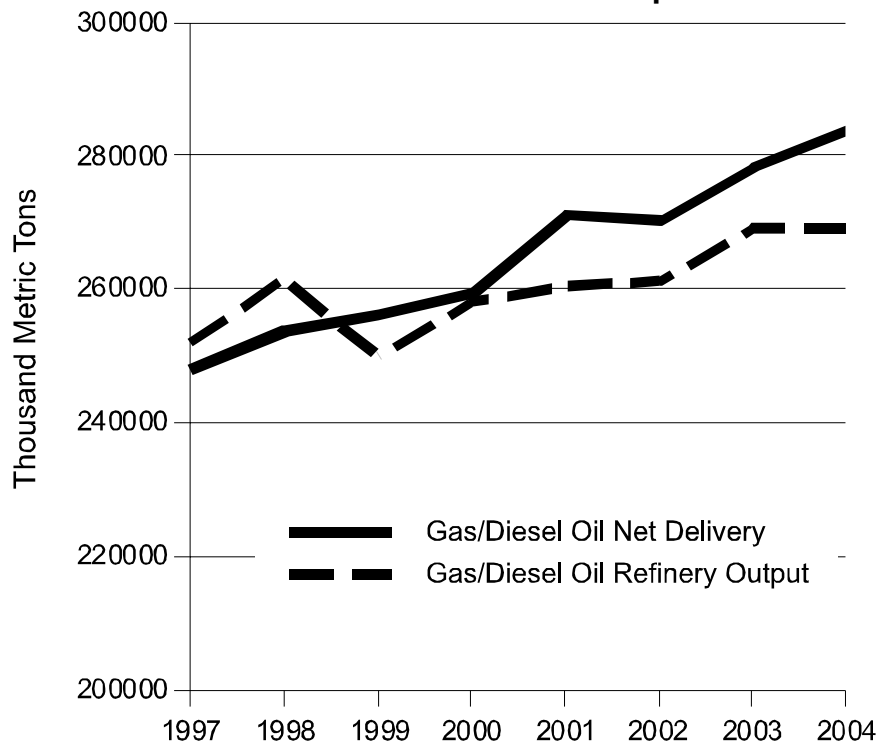
⁵³ Ward's Automotive Yearbook 2005, *U.S. Diesel Car Market Share*, p. 36.

⁵⁴ U.S. DOE EIA, *Can U.S. Supply Accommodate Shifts to Diesel-Fueled Light-Duty Vehicles?*, Oct. 7, 2005.

⁵⁵ "The Changing Face of Europe's Car Industry," *The Economist Newspaper Ltd*, Mar. 24, 2005.

⁵⁶ International Energy Agency, IEA Energy Statistics, *Monthly Oil Survey*, at [<http://www.iea.org/Textbase/stats/oilresult.asp>], visited Apr. 12, 2006.

Figure 5. Net Deliveries vs. Refinery Output of Gas/Diesel Oil for OECD Europe



Source: International Energy Agency, *Monthly Oil Survey*, 2000 through 2005.

CO, NO_x, and PM Emissions. Compared with spark-ignition (gasoline) engines, compression-ignition (diesel) engines characteristically emit lower amounts of carbon monoxide (CO) and carbon dioxide (CO₂), but they emit higher amounts of nitrogen oxides (NO_x) and particulate matter (PM). NO_x is the primary cause of ground-level ozone pollution (smog) and presents a greater problem, technically, to reduce in diesel engines than PM.

The CO, NO_x, and PM emissions for gasoline and diesel engines are regulated by the 1990 Clean Air Act amendments (42 U.S.C. 7401-7671q) Tier 1 and 2 Emission Standards. Under Tier 1, the NO_x standard had been 1.0 gram/mile for diesel passenger and light-duty trucks, versus 0.4 grams/mile for gasoline vehicles. The Tier 2 standards that started taking effect in 2004 are fuel-neutral. Regardless of the fuel, a fleet of vehicle models manufactured in a given year must average 0.07 grams/mile for NO_x emissions. A particular vehicle model may qualify in a unique emission “bin” (the maximum allowable is 0.2 grams/mile), as long as the fleet of models meets the average NO_x emission standard. Other pollutants are similarly regulated.

Since diesel engines inherently produce more NO_x and PM than gasoline engines, producing more diesel vehicles raises the fleet emission average and thus limits the total number of vehicles a manufacturer can sell in the United States. This in turn limits the demand for diesel vehicles, which thus limits the opportunity for oil-shale distillates. The U.S. Tier 2 NO_x emissions standards are more stringent

than the EU's current Euro 4 standards of 0.4 grams/mile for diesel cars and 0.6 grams/mile for light-duty diesel trucks. Tier 2 PM-emission standards of 0.01 to 0.02 grams/mile are also more stringent than Euro 4 PM-emissions of 0.04 grams/mile.

The Tier 2 CO-standard of 4.2 grams/mile is significantly less stringent than the Euro 4 standard of 0.8 grams/mile for diesel passenger cars and 1.2 grams/mile for light-duty diesel trucks. Tier 2 favors gasoline over diesel in this case.

The EU is moving toward taxing cars on the basis of CO₂ emissions (which favors diesel).⁵⁷ This move is in response to the Kyoto Protocol on climate change, which seeks to limit CO₂ emissions, a treaty that the United States signed but did not ratify.

Should oil-shale distillates substitute for diesel, Tier 2 limits on CO, NO_x, and PM emissions would continue to apply, as the standard is fuel-neutral. However, the emission characteristics of oil-shale distillates (similar to diesel) have not been the subject of documented research.

Ultra-Low Sulfur Diesel. By mid-2006, new U.S. standards for ultra-low sulfur diesel (ULSD) take effect under a 2001 rule issued by the EPA.⁵⁸ Diesel fuel sulfur content must be reduced to no more than 15 parts-per-million (ppm) from the current 500 ppm (established by a 1993 rule that reduced the level from 5,000 ppm). However, to account for pipeline contamination, refiners may have to produce diesel fuel with a sulfur content as low as 7 ppm; a four-year phase-in period allows for 20% of the highway diesel produced to meet the current limit.

The EIA estimates the marginal cost of producing ultra-low sulfur diesel to range from 2.5¢ to 6.8¢ per gallon, depending on whether supply falls short of demand or consumers bid up the price.⁵⁹ EIA projects the ULSD rule to require total refinery investments ranging from \$6.3 to \$9.3 billion. As the energy content of ULSD is somewhat less than 500 ppm diesel, fuel efficiency may be affected (increasing fuel consumption and therefore demand).

The sulfur content of oil-shale distillates is comparable in weight percentage to crude oil (**Table 1**). U.S. refiners were able to meet the current 500 ppm requirement by increasing the existing capacity of their hydrotreatment units and adding new units. However, refineries may face difficulty in treating diesel to below 500 ppm. The remaining sulfur is bound in non-hydrocarbon, multi-ring thiophene-type compounds that prove difficult to hydrotreat because the molecular ring structure attaches the sulfur on two sides. Although these compounds occur throughout the range of petroleum distillates, they are more concentrated toward the residuum end.

⁵⁷ "Emission Taxes Could Displace Registration Taxes," *The Economist Newspaper Ltd.*, Mar. 24, 2005.

⁵⁸ U.S. EPA, "Control of Air Pollution from Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR, Parts 69, 80, and 86.

⁵⁹ U.S. DOE EIA, *The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply*, May 2001.

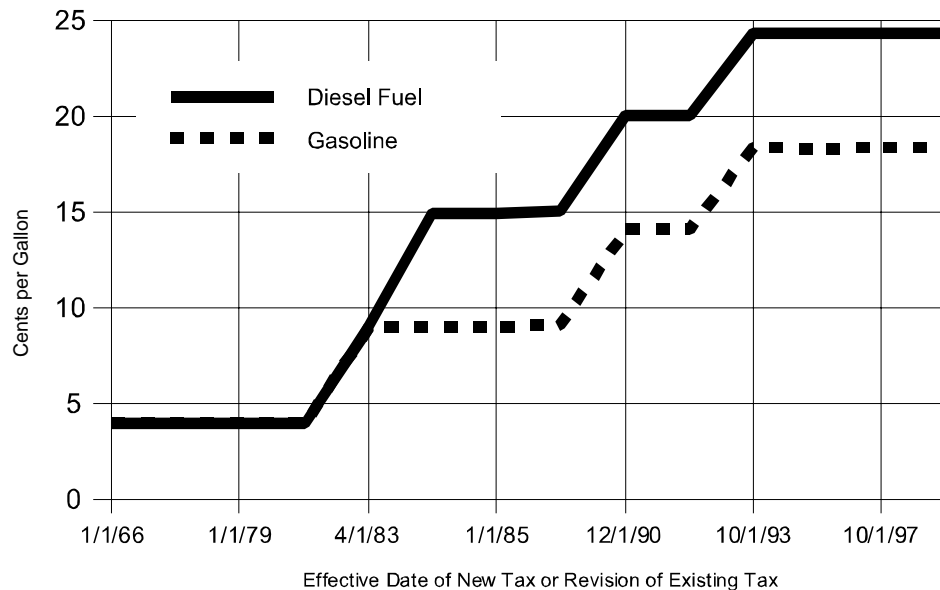
So, the problem is compounded when residuum is cracked to increase gasoline production. Improved hydrotreatment technology since the 1980s has increased sulfur removal and provided a means to removing oil-shale distillate's excessive nitrogen content (desirable in terms of producing stable fuels with low NOx emissions).

Whereas conventional refineries may be able to further upgrade hydrotreatment capacity by retrofitting, an oil shale processing plant would be designed and built from the ground up with necessary capacity. However, many refineries either produce the hydrogen needed for hydrotreating or purchase it from vendors that operate near established refining centers. An oil shale facility may require the addition of a steam reforming process to convert natural gas to the hydrogen needed.

Refiners' response to the ULSD rule ultimately affects diesel supply and thus price. As increased diesel fuel prices are likely to erode the lower operating-cost advantage of diesel engines over gasoline, the incentive for purchasing light-duty diesel vehicles would be less, in keeping with EIA's projection of a slow growth in light-duty diesel vehicles over the next decade. On the other hand, a decline in diesel demand would offer even less incentive to produce oil-shale distillates for light-duty vehicles.

Fuel Tax. The U.S. federal tax rate on motor fuel currently favors gasoline over diesel fuel by 6¢ per gallon (18.4¢ and 24.4¢, respectively).⁶⁰ Both gasoline and diesel tax rates began increasing after the mid-1980s, but diesel increased at a faster rate (**Figure 5**). The higher diesel fuel tax is essentially a user fee paid by heavy-duty trucks to offset the higher road damage they cause than lighter duty vehicles. Where motor fuel taxes are applied to transportation infrastructure improvements in the United States, they are a source of general revenue for the 15 EU member states.

⁶⁰ U.S. DOT, "Federal Tax Rates on Motor Fuels and Lubricating Oil," Table Fe-101a., at [<http://www.fhwa.dot.gov/policy/ohim/hs03/htm/fe101a.htm>]. The effective tax rate on gasoline and diesel terminated Oct.1, 2005; new rates have not yet been published.

Figure 6. Diesel vs Gasoline Fuel Tax

Source: U.S. DOT, “Federal Tax Rates on Motor Fuels and Lubricating Oil,” Table Fe-101a.

Note: The U.S. federal tax rate on motor fuel currently favors gasoline over diesel fuel by 6¢ per gallon. European Union states (except UK) tax diesel fuel on average (62¢/gallon less than gasoline).

Overall, motor fuel taxes are significantly higher in the EU, ranging from the equivalent of \$3.28/gallon (€742/1,000 liters at an exchange rate of \$1.17: €1) for diesel and gas in the United Kingdom, to as low as €253/1,000 liters) (\$1.12/gallon) for diesel in Luxemburg. Except for the United Kingdom, diesel fuel is taxed on average 62¢/gallon (€140/1,000 liters) less than gasoline.⁶¹ In December 2005, the average end-use prices of gasoline in France and Germany were \$5.26/gallon and \$6.08/gallon, respectively (€1.170/liter and €1.226/liter), compared with \$2.17/gallon in the United States — with automotive diesel averaging \$3.89/gallon and \$4.23/gallon in France and Germany, respectively (€0.865/liter and €0.941/liter), compared with \$2.45/gallon in the United States.⁶² The end-use price difference in the two fuels appears to correlate with the increasing registration of diesel cars in the EU. With higher crude oil prices, the fuel savings advantage of diesel cars should become even more compelling.

Diesel fuel demand is “regulatory driven” to an extent. Motor fuel taxes that favor diesel over gasoline offer one means of redirecting demand, but the tax differential may need to be significantly higher than the current 6¢ per gallon differential favoring gasoline. Raising motor fuel taxes above the current federal level runs counter to current policy. In the aftermath of Hurricane Katrina, when gasoline prices surged above \$3 per gallon, some states suspended or considered suspending taxes on gasoline. However, advocates of energy conservation argued

⁶¹ EurActive, *Fuel Taxation*, Nov. 25, 2003, at [http://www.euractiv.com/Article?tcaturi=tcm:29-117495-16&type=LinksDossier], visited Apr. 5, 2006.

⁶² International Energy Agency, *End-user Petroleum Product Prices and Average Crude Oil Import Costs, December 2005*, Jan. 6, 2006.

that the higher gasoline prices conserved fuel by discouraging driving, thus the motor fuel tax should have remained or even increased. If higher motor fuel tax stimulates the demand for more fuel-efficient vehicles, as the European experience suggests, the inherent fuel efficiency offered by a diesel passenger vehicle becomes more apparent, if not desirable. This in turn could act as an additional incentive for producing diesel or alternatives such as oil-shale distillates.

Policy Perspective and Consideration

Federally sponsored research to develop fuel substitutes from oil shale dates back the U.S. Synthetic Liquid Fuels Act of 1944 out of World War II concerns for oil supplies. Later, in response to the oil embargos of the 1970s, Congress created the Synthetic Fuels Corporation. National security had been a motivating concern (i.e., to aid the prosecution of the war and to contend with foreign actions that interrupt energy supplies). As newly discovered, less-costly-to-produce petroleum reserves entered production in the early 1980s, the economic and operating conditions of oil shale production became unfavorable. As commercial interests backed out of projects, Congress terminated synthetic fuel development. Various commercial attempts to exploit the resource met with limited success. Technological developments that transformed petroleum refining efficiency, and the discovery of new petroleum reserves, shifted private sector interest away from oil shale resources.

The global demand-driven petroleum supply cycle, if true to history, is likely to exhibit periods of surplus and shortage. Periods of surplus fit well with the just-in-time supply model that seeks to hold down inventory costs by minimizing stocks on hand. Proponents of the self-correcting petroleum market theory may argue that supply interruptions are temporary and that price spikes signal customers to reduce consumption. Opponents may argue that reduced consumption is not an option during a national security crisis and that there ought to be a “just-in-case” contingency in place, such as oil shale. While the threat from future OPEC-like embargoes appears unlikely, the President’s goal “to replace more than 75 percent of our oil imports from the Middle East by 2025” indicates continuing concern.⁶³

Recent high crude oil prices renewed interest in oil shale, prompting Congress to include provisions in the Energy Policy Act of 2005 promoting the lease and development of federal oil shale holdings. The Act also identified oil shale as a strategically important domestic resource and directed the Energy Department to coordinate and accelerate its commercial development.

The misconception persists, however, regarding oil shale’s fungibility as a crude oil substitute. It doesn’t effectively replace crude oil as a gasoline feedstock. Thus, policies that attempt to foster oil shale development come into conflict with regulatory policies that favor gasoline as transportation fuel. The best use of the resource appears to be as feedstock for producing middle-distillate fuels. Regulatory policies that are acting to discourage wider use of middle-distillate fuels thus may be acting as a disincentive to oil shale production. Congress may wish to consider

⁶³ President George W. Bush, *State of the Union*, Jan. 31, 2006.

whether a special case should be made for oil shale, and whether to exempt the middle-distillate fuels produced from regulatory policies that restrict their wider use as transportation fuels.

The President's FY2007 budget request would terminate the Energy Department's oil technology research, and the Defense Department's initiative to develop clean fuels from oil shale (among other resources) appears unfunded.⁶⁴

Whether oil shale can be economically produced, even given the current high cost of conventionally recovered petroleum, remains unclear. However, without a long-term concerted effort to produce oil shale, either through a federal- or private sector-sponsored enterprise, the economic viability will remain questionable. The expectation of initial high unit costs should be weighed against the offset in demand for imported products and the effect on lowering price that competition brings.

⁶⁴ Personal communication with Dr. Theodore K. Barna, Feb. 8, 2006.

Appendix: Legislative History

The Pickett Act of 1910 initially authorized withdrawal of potential oil-bearing lands in California and Wyoming as sources of fuel for the Navy. Executive orders later created three Naval Petroleum and Oil Shale Reserves between 1912 and 1927 by setting aside federal lands believed to contain oil as an emergency reserve.

The U.S. Synthetic Liquid Fuels Act of 1944 (30 USC Secs. 321 to 325) authorized \$30 million over five years for “the construction and operation of demonstration plants to produce synthetic liquid fuels from coal, oil shales, agricultural and forestry products, and other substances, in order to aid the prosecution of the war, to conserve and increase the oil resources of the Nation, and for other purposes.” The act also authorized the Interior Secretary to construct, maintain, and operate plants producing synthetic liquid fuel from coal, oil shale, and agricultural and forestry products. The Bureau of Mines received \$87.6 million for an 11-year demonstration plant program.

The Defense Production Act of 1950 (Ch. 932, 64 Stat. 798), enacted during the Korean War, was intended to develop and maintain whatever military and economic strength necessary to support collective action through the United Nations. The diversion of certain materials and facilities from civilian to military use required expansion of production facilities beyond the levels needed to meet civilian demand. Section 303 of Title III (Expansion of Production Capacity and Supply) authorized the President “extraordinary” procurement power to have liquid fuels processed and refined for government use or resale, and to make improvements to government or privately owned facilities engaged in processing and refining liquid fuels when it would aid the national defense. In 1980, Congress added provisions (P.L. 96-294) that related to preparing for terminated or reduced availability of energy supplies for national defense needs. Section 305 of the act authorized the President to purchase synthetic fuels for the purpose of national defense. Executive Order 12242 then directed the Secretary of Defense to determine the quantity and quality of synthetic fuel needed to meet national defense needs for procurement.

The Naval Petroleum Reserves Production Act of 1976 (P.L. 94-258), in reference to Naval Petroleum Reserve No. 4 in Alaska, defined petroleum to include crude oil, gases (including natural gas), natural gasoline, and other related hydrocarbons, oil shale, and the products of such sources.

The Department of Energy Organization Act of 1977 (P.L. 95-91) transferred control of the Naval Petroleum and Oil Shale Reserves from the Navy to the Department of Energy.

The United States Synthetic Fuels Corporation Act of 1980 (P.L. 96-294)⁶⁵ amended the Defense Production Act by establishing the U.S. Synthetic Fuels Corporation (SFC) “to improve the Nation’s balance of payments, reduce the threat of economic disruption from oil supply interruptions, and increase the Nation’s

⁶⁵ Title I, Part B of the Energy Security Act of 1980.

security by reducing its dependence on foreign oil.” The corporation was authorized to provide financial assistance to qualified projects that produced synthetic fuel from coal, oil shale, tar sands, and heavy oils. Financial assistance could be awarded as loans, loan guarantees, price guarantees, purchase agreements, joint ventures, or combinations of those types of assistance. An Energy Security Reserve fund was also established in the U.S. Treasury and appropriated \$19 billion to stimulate alternative fuel production. Executive Order 12242 (1980) directed the Secretary of Defense to determine the quantity and quality of synthetic fuel needed to meet national defense needs for procurement under the Defense Production Act. Executive Order 12346 (Synthetic Fuels) of 1982 revoked EO 12242 and provided for an orderly transition of synthetic fuel responsibilities from the Department of Energy to the United States Synthetic Fuels Corporation.

The Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223) ostensibly provided revenue to maintain the Energy Security Reserve fund. The Internal Revenue Code was amended to impose an excise tax on windfall profits of domestic producers of taxable crude oil. A production tax credit of \$3.00 (1979 dollars) per barrel of oil equivalent was provided to stimulate oil shale development. The House conference report (H. Rept 96-817) projected \$227.3 billion in total revenue from the tax after 1988. In the Windfall Profit Tax Account established to hold the revenue, 15% had been allocated for energy and transportation. In 1983, the Congressional Budget Office estimated that the revenue would only reach 40% of the conference report’s projection and only 20% by 1988, as the price of crude oil had been lower than projected. Congress repealed the windfall profit tax in 1988 (P.L. 100-418).

The House began considering a bill to abolish the SFC with the Synthetic Fuels Fiscal Responsibility Act of 1985 (H.R. 935). The Energy and Commerce Committee debate of the bill (Rept. 99-196) linked abolishing the Corporation to reducing the federal deficit and viewed purchasing oil for the Strategic Petroleum Reserve as a far more cost effective defense against another embargo by OPEC than subsidizing synthetic fuels. The minority view noted that as late as 1983, the Department of Defense had certified that synthetic fuel was needed to meet national defense needs under Executive Order 12242. In September 1985, the Senate Committee on Appropriations report (S.Rept. 99-141) recommended increasing the Department of Energy Oil Shale Program budget and reaffirmed the goal of oil shale reserves supplying petroleum during a national emergency. Support for the SFC could not be sustained, and Congress terminated it under the Consolidated Omnibus Reconciliation Act of 1985 (P.L. 99-272). Remaining obligations were transferred to the Treasury Department, and the duties of the Chairman of the SFC Board were transferred to the Secretary of the Treasury.

The Department of Energy Organization Act of 1977 (P.L. 95-91) transferred Navy control of the NOSRs to the Department of Energy. The National Defense Authorization Act of 1998 (P.L. 105-85) transferred NOSR Nos. 1 and 3, located near Rifle, Colorado, from the Department of Energy to the Bureau of Land Management. The National Defense Authorization Act of 2000 (P.L. 106-398) transferred NOSR No. 2 in Utah to the Ute Indian Tribe.

The Oil Shale, Tar Sands, and Other Strategic Unconventional Fuels Act of 2005⁶⁶ declares the strategic importance of domestic oil shale resources and their development. The act directs the Secretary of the Interior to commence commercial leasing of oil shale on public lands and to establish a task force in cooperation with the Secretary of Defense to develop a program for commercially developing strategic unconventional fuels, including but not limited to oil shale. Section 2398a. (Procurement of Fuel Derived from Coal, Oil Shale, and Tar Sands) directs the Secretary of Defense to develop a strategy to use fuel produced from oil shale to help meet the fuel requirements of the Department of Defense when the Secretary determines that doing so is in the national interest

⁶⁶ Section 369 of the Energy Policy Act of 2005.