

**APPENDIX A:
OIL SHALE DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW**

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OIL SHALE DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW

This appendix describes the geology of the oil shale resource area, the resource, and the history of oil shale development in the western United States, and it provides an overview of the technologies that have been applied to oil shale development. Technologies that may be employed in future developments on U.S. Department of the Interior (DOI), Bureau of Land Management (BLM)-administered lands are introduced. Technologies that are addressed in the *Proposed Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Final Programmatic Environmental Impact Statement (PEIS)* include those used for recovery (i.e., mining), processing (i.e., retorting and pyrolysis of the hydrocarbon fraction), and upgrading of oil shale resources.¹ Assumptions regarding these technologies were developed to support analyses in the PEIS and are also presented in this appendix. Finally, Attachment A1 provides an analysis of how the refinery industry may adjust to the availability of syncrude feedstocks derived from oil shale.

Currently, there is no commercial production of oil from oil shale being undertaken in the United States. While recently there has been a great deal of interest in the potential of oil shale resources, utilization of this material is still in the research and development mode. Recent technological developments have proven to be of great interest, and those developments, along with technologies that were developed during the last wave of interest in oil shale, are now being considered for application in tapping this potential resource.

Development of oil shale resources is expected to proceed gradually and to be led by activities on the six sites located in Colorado and Utah (see Section 1.4.1 of the main text of the PEIS) that are included in the BLM's oil shale research, development, and demonstration (RD&D) program. Chapter 9 of the PEIS provides a glossary of technical terms, including geologic terms, used in the PEIS and its appendices.

A.1 DESCRIPTION OF GEOLOGY

Oil shale is a term used to cover a wide range of fine-grained, organic-rich sedimentary rocks. Oil shale does not contain liquid hydrocarbons or petroleum as such but organic matter derived mainly from aquatic organisms. This organic matter, kerogen, may be converted to oil through destructive distillation or exposure to heat.

Numerous deposits of oil shale are found in the United States. The most prospective shale deposits are contained within sedimentary deposits of the lacustrine Green River Formation of

¹ Retorting and pyrolysis are key steps in oil shale processing. Retorting is a process that causes thermal decomposition of the organic fraction of the oil shale (kerogen). The recovered organic fraction is then distilled, or pyrolyzed, to produce three products: crude shale oil, flammable gases (including hydrogen), and char (deposited on spent shale). These processes are described further in Section A.3.2.

Eocene age. These deposits exist in the greater Green River Basin (including Fossil Basin and Washakie Basin) in southwestern Wyoming and northwestern Colorado, the Piceance Basin in northwestern Colorado, and the Uinta Basin in northeastern Utah.² Because of the deposits' size and grade, most investigations have focused on the oil shale deposits in these basins. As discussed in Section 1.2 of the main text of the PEIS, in defining the scope of analysis for the PEIS, the BLM identified the most geologically prospective areas for oil shale development on the basis of the grade and thickness of the deposits. For the purposes of this PEIS, the most geologically prospective oil shale resources in Colorado and Utah are defined as those deposits that are expected to yield 25 gal of shale oil per ton of rock (gal/ton) and are 25 ft thick or greater. In Wyoming, where the oil shale resource is not of as high a quality as it is in Colorado and Utah, the most geologically prospective oil shale resources are those deposits that are expected to yield 15 gal/ton or more shale oil and are 15 ft thick or greater. Figure A-1 shows the Green River Formation basins, which were mapped on the basis of the extent of the Green River Formation, and the most geologically prospective oil shale resources within those basins.³

In addition to limiting the scope of analyses to the most geologically prospective resources, the BLM has determined that, for the purposes of establishing a commercial leasing program for oil shale development on public lands, oil shale resources that are covered by more than 500 ft of overburden would not be available for application for leasing using surface mining technologies under the scope of this PEIS. This limitation is based on the assumption that 500 ft is about the maximum amount of overburden where surface mining can occur economically, using today's technologies. Figure A-1 shows the areas within the three-state region where surface mining would be considered under the commercial leasing program on the basis of the overburden thickness.⁴ Although some of the oil shale resources outcrop in Colorado and have overburden thicknesses of less than 500 ft, the distribution of these areas presents a relatively narrow band of lands within which it would be difficult to assemble a logical mining unit; therefore, surface mining projects in Colorado are not evaluated in this PEIS.

² The Piceance Basin is not referred to or described consistently in published literature. Some publications describe the Piceance Basin as an area encompassing more than 7,000 mi² and consisting of a northern province and a southern province, separated approximately by the Colorado River and Interstate 70 (I-70). Other publications refer to the southern province as the Grand Mesa Basin. Oil shale is present in both provinces, with the richest oil shale deposits in the north, and smaller, isolated deposits in the south. Various authors have used the terms "Piceance Basin" and "Piceance Creek Basin" to refer to either the overall basin or the northern area. In this PEIS, the focus is on the northern province, where the richest and thickest reserves are located, and the study area will be referred to as the "Piceance Basin."

³ Numerous sources of information were used to define the boundaries of the Green River Formation basins and the most geologically prospective oil shale resources. The basin boundaries were defined by digital data provided by the U.S. Geological Survey (USGS) taken from Green (1992), Green and Drouillard (1994), and the Utah Geological Survey (2000). The most geologically prospective oil shale resources in the Piceance Basin were defined on the basis of digital data provided by the USGS taken from Pitman and Johnson (1978), Pitman (1979), and Pitman et al. (1989). In Wyoming, the most prospective oil shale resources were defined on the basis of detailed analyses of available oil shale assay data (Wiig 2006a,b). In Utah, the most prospective oil shale resources were defined by digital data provided by the BLM Utah State Office.

⁴ The areas within the most geologically prospective oil shale areas where the overburden is 0 to 500 ft thick were mapped on the basis of a variety of sources of information. In Colorado, the area was defined on the basis of data published in Donnell (1987). In Utah, the area was mapped on the basis of data provided by the Utah Geological Survey (Tabet 2007). In Wyoming, the area was mapped on the basis of data provided by Wiig (2006a,b).

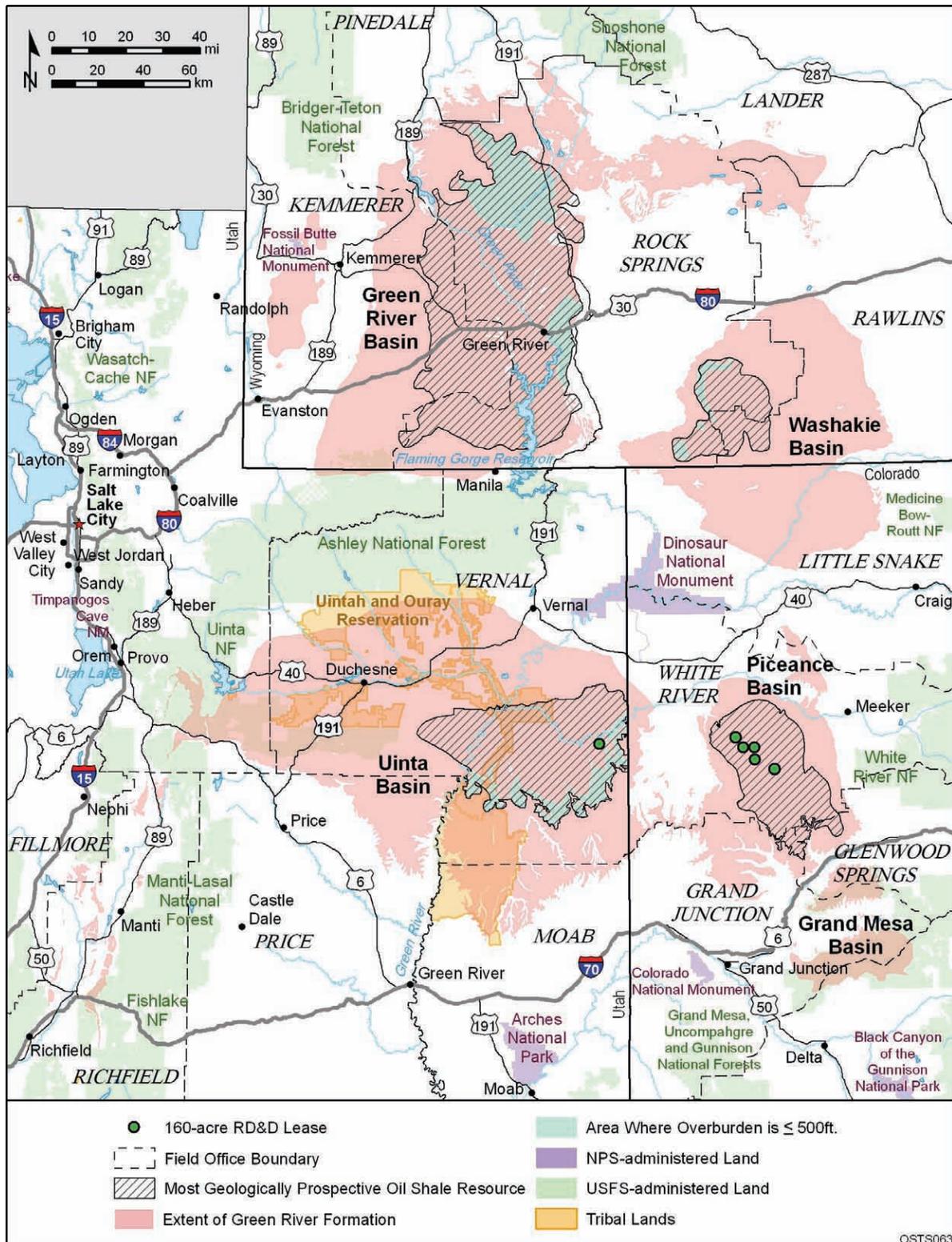


FIGURE A-1 Green River Formation Basins in Colorado, Utah, and Wyoming; Most Geologically Prospective Oil Shale Resources; Areas Where the Overburden above the Oil Shale Resources is \leq 500 ft; and Locations of the Six RD&D Projects

A.1.1 Depositional Environment

The Green River Formation was originally deposited in two basins that were later warped into four large structural basins and then elevated several thousand feet above mean sea level (MSL). The major streams and their tributaries traversing the region have eroded much of the sediments from these exhumed basins. The stream erosion has exposed the oil shale on cliffs and ledges in many places. Gentle folds and minor faults deform the deposits locally, but the sedimentary rocks of the oil shale areas as a whole are remarkably undisturbed structurally. Exceptions occur in the areas where the strata are steeply tilted on the flanks of the Uinta Mountains in Utah and Wyoming and along the Grand Hogback in Colorado.

Lacustrine sediments of the Green River Formation that have become oil shale were deposited in two large lakes that occupied 24,000 mi² in several sedimentary structural basins in Colorado, Wyoming, and Utah during early through middle Eocene time (40 to 65 million years ago). These basins are separated by the Uinta Mountain uplift and its eastward extension, the Axial Basin anticline. The Green River lake system was in existence for more than 10 million years during a time of a warm-temperate to subtropical climate. The two large lakes initially were freshwater but became quite saline with time.

Fluctuations in the amount of inflowing stream waters caused large changes in the areal extent of the lakes as evidenced by widespread intertonguing of marly (clay and carbonate-rich) lacustrine strata with beds of land-derived sandstone and siltstone. During arid times, the lakes contracted in size and the lake waters became increasingly saline and alkaline. The lake-water content of soluble sodium carbonates and chloride increased, while the less soluble calcium, magnesium, and iron carbonates were precipitated with organic-rich sediments.

During the driest periods, the lake water reached salinities sufficient to precipitate the sodium minerals nahcolite, halite, and trona. The water filling the pore spaces in the sediments was also sufficiently saline to precipitate disseminated crystals of nahcolite, halite, and dawsonite along with a host of other carbonate and silicate minerals (Milton 1977). In Wyoming (Lake Gosiute), trona was precipitated. In Colorado (Lake Uinta), the minerals halite, nahcolite, and dawsonite were precipitated. Why the two lakes precipitated different mineral salts is unknown, but the resulting deposits of trona, nahcolite, and dawsonite constitute an immense potential mineral supply.

The warm, alkaline waters of the Eocene Green River lakes provided excellent conditions for the abundant growth of blue-green algae (cyanobacteria) that is thought to be the major precursor of the organic matter in the oil shale. During times of freshening waters, the lakes hosted a variety of fishes, rays, bivalves, gastropods, ostracods, and other aquatic fauna. Areas peripheral to the lakes supported a large and varied assemblage of land plants, insects, amphibians, turtles, lizards, snakes, crocodiles, birds, and numerous mammals (McKenna 1960; MacGinitie 1969; Grande 1984). These areas where saline minerals are intermixed with oil shale are referred to in this document as “multimineral zones.”

A.1.2 Piceance Basin, Colorado

The Piceance Basin is located mainly in the Colorado Plateau physiographic province. The overall basin is more than 100 mi long and 60 mi wide, with an area more than 7,000 mi². The Piceance Basin is simultaneously a structural, depositional, and drainage basin. The structural basin is downwarped and surrounded by uplifts resulting from the Laramide Orogeny. This tectonic activity created a depositional basin that filled with sediments from the surrounding uplands, mainly during the Tertiary period. The basin has a northern province and a southern province (Topper et al. 2003) separated approximately by the Colorado River and I-70. Oil shale is present in both provinces.

Within the Piceance Basin, the upper bedrock stratigraphy consists of a series of basin-fill sediments from the Tertiary period (Topper et al. 2003). The uppermost unit is the Uinta Formation, which consists of up to 1,400 ft of Eocene-age sandstone, siltstone, and marlstone. Below the Uinta Formation is the Eocene Green River Formation, which can be up to 5,000 ft thick and includes four members: the Parachute Creek (keragenous dolomitic marlstone and shale), the Anvil Points (shale, sandstone, and marlstone), the Garden Gulch (claystone, siltstone, clay-rich oil shale, and marlstone), and the Douglas Creek (siltstone, shale, and sandstone). The Eocene-Paleocene Wasatch Formation underlies the Green River Formation and is approximately 6,900 ft thick near the town of Rifle, Colorado. Exposed Wasatch rocks include clays and shales with some interbedded sandstone and are found in the lowest elevations between the base of the cliffs and the major streams (the Colorado River, Government Creek, and Parachute Creek). The Wasatch Formation is a significant oil and natural gas-producing unit in the region. Below the Wasatch are the Cretaceous Mesaverde Group (sandstone and shale), the Cretaceous Mancos Shale, and older sedimentary formations atop Precambrian rock. The Mesaverde Group is the major oil- and gas-producing formation in the Piceance Basin.

The main oil shale members of interest in the Piceance Basin are the Parachute Creek and Garden Gulch Members. The grade of oil shale varies with location and depth, but the Parachute Creek Member has the richest material and includes the Mahogany Zone.

Elsewhere in the region, the Grand Hogback exposes Paleozoic and Mesozoic sedimentary bedrock units that dip steeply to the west and southwest. Tertiary basalt flows cover much of the higher-elevation areas south of the Colorado River (i.e., Battlement Mesa) and the White River Plateau to the northeast. Quaternary alluvium occurs as a broad belt along the lower reaches of Parachute, Rifle, and Government Creeks and along the Colorado River (Widmann 2002). Quaternary alluvium of varying thickness is present in the significant drainages of the basin.

Although the oil shale deposits in Colorado cover the smallest geographical area, they are the richest, thickest, and best-known deposits. In addition, natural gas production is prolific from formations located stratigraphically below the oil shale, with 4 of the top 35 natural gas fields in the United States located in the southern Piceance Basin. Substantial quantities of saline minerals (halite, dawsonite, and nahcolite) are intermixed or intermingled with oil shale in certain zones in the northern half of the basin. Three layers of nahcolite are present near the base of this saline zone, and two halite-bearing strata exist in the upper part of the zone. The dawsonite and other

saline minerals are finely disseminated in and associated with beds of oil shale, which are up to 700 ft thick near the center of the basin. Dyni (1974) estimated the total nahcolite resource at 29 billion tons. Beard et al. (1974) estimated nearly the same amount of nahcolite and 17 billion tons of dawsonite. Both minerals have value for soda ash and aluminum, respectively. Dawsonite has potential value for its alumina content and most likely would be recovered as a by-product of an oil shale operation. One company is presently solution mining about several hundred thousand tons/yr of nahcolite in the northern part of the Piceance Basin at depths of about 1,970 ft (Day 1998). The BLM has identified an area in the Piceance Basin, referred to as the Multiminerals Zone, where development of nahcolite, dawsonite, or oil shale cannot result in destruction of another resource.

About 80% of the potential oil shale resources of the Green River Formation, or about 1.2 trillion bbl of oil equivalent, is found in west-central Colorado's Piceance Basin. Of the total potential resource, about 480 billion bbl are contained in deposits averaging at least 25 gal/ton. The higher-grade shale sections range from 10 ft to more than 2,000 ft in thickness and may be covered with overburden ranging up to 1,600 ft thick.

A.1.3 Uinta Basin, Utah

In Utah, oil shale deposits are found in the Parachute Creek Member of the Green River Formation, which intertongues with but generally occurs above the Douglas Creek Member. As many as eight oil shale zones have been identified in the Parachute Creek Member; the richest oil shale is found in the Mahogany Zone, which contains up to 100 ft or more of rock that averages 15 gal/ton. Figure A-2 is a generalized stratigraphic section of the rich and lean oil shale zones of the Parachute Creek Member of the Green River Formation in the Uinta Basin, Utah. The thickness of the different zones shown in the stratigraphic section is not constant but varies across the basin. No single comprehensive and modern study of the oil shale resources of the entire Uinta Basin has been carried out. An early study of the Uinta Basin (Cashion 1967), based on less data than are available today, yielded a potential resource estimate for the Mahogany Zone that is at least 15 ft thick and contains an average yield of at least 25 gal/ton of 26.8 billion bbl (Table A-1). A more recent study (Trudell et al. 1973), based on a greater amount of drilling data but limited to the southeastern

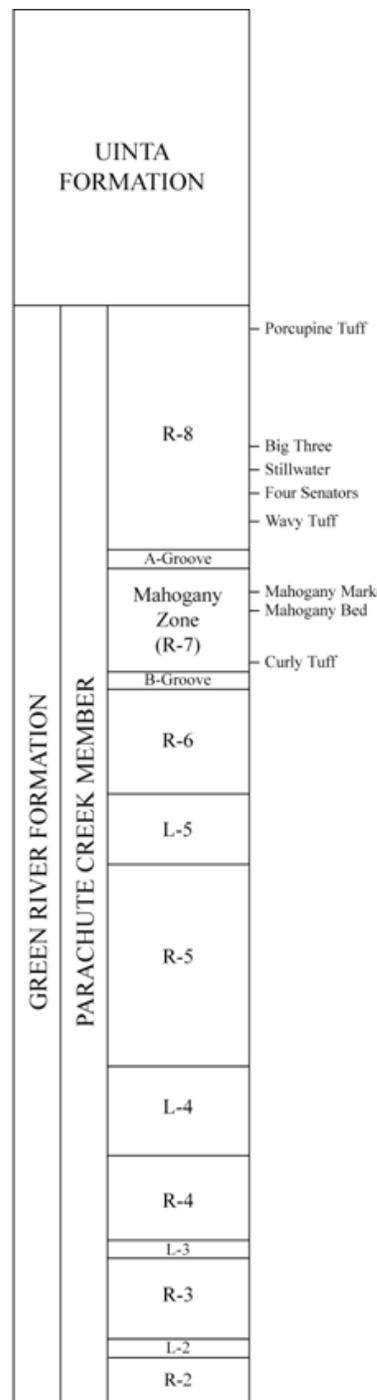


FIGURE A-2 Generalized Stratigraphic Section of the Parachute Creek Member of the Green River Formation in the Uinta Basin, Utah (“R” = rich oil shale zone; “L” = lean oil shale zone [adapted from Young 1995])

TABLE A-1 Estimated In-Place Oil Shale Resources in the Southeastern Portion of the Uinta Basin Based on a Minimum Thickness of 15 ft and Various Expected Yields (in gal/ton)^a

Green River Formation Mahogany Zone	Acreage	Average Resource (bbl/acre)	Total In-Place Resource (million bbl)
<i>At depths <3,000 ft below the surface</i>			
Average yield of 30 gal/ton	293,787	63,485	18,651
Average yield of 25 gal/ton	361,990	74,093	26,821
Average yield of 15 gal/ton	426,507	117,126	49,955

^a 1 bbl shale oil = 42 gal.

Source: Cashion (1967); higher yield portions are subsets of the 15 gal/ton resource.

portion of the Uintah Basin, estimated that within the Mahogany Zone, which is at least 25 ft thick and contains an average of 25 gal/ton, there is a resource of at least 31 billion bbl (Table A-2). This upward resource revision indicates that the early estimate provided by Cashion (1967) is conservative, and that more work is necessary to comprehensively define the oil shale resource potential of the entire Uinta Basin.

A major fault, the Uinta Basin boundary fault, lies in the subsurface near the northern margin of the Uinta Basin (Campbell 1975). In the Wasatch Plateau along the western margin of the Uinta-Piceance Province, several north-south fault systems that are an eastward extension of basin and range-style tectonism disrupt the geologic units. The Uinta Basin is filled by as much as 17,000 ft of Upper Cretaceous and Paleogene lacustrine and fluvial sedimentary rocks (Bradley 1925; Cashion 1967; Fouch 1985). On the Douglas Creek arch, which separates the Uinta Basin from the Piceance Basin, the Green River Formation has been eroded away. Uppermost Cretaceous and lowermost Tertiary strata dip 4° to 6° toward the axis of the Uinta Basin. The younger Uinta and Duchesne River Formations of late Eocene to earliest Oligocene age dip less steeply. The Green River Formation reaches a maximum depth of 20,000 ft along the basin axis in the north-central part of the Uinta Basin. The Green River Formation lies below the Altamont-Bluebell oil field (Fouch et al. 1994). The Green River Formation contains significant oil- and gas-producing reservoirs in the Uinta Basin, including those at Altamont-Bluebell, Cedar Rim, Brundage Canyon, Monument Butte, Eight Mile Flat North, Uteland Butte, Pariette Bench, Natural Buttes, Horseshoe Bend, and Red Wash fields. The eastern Uinta Basin also hosts significant gas-producing reservoirs in deeper Tertiary and Cretaceous reservoirs over much of the same area containing valuable oil shale deposits in the Green River Formation. Conflicts with conventional oil and gas development in the Uinta Basin may be an obstacle to the future development of Utah's oil shale deposits.

The largest areal extent of the oil shale-bearing Green River Formation occurs in Utah. The richest shales in Utah occur in the east-central part of the Uinta Basin, at depths ranging from 0 ft at the outcrop to 4,800 ft below the surface. These rich deposits contain more than 300 billion bbl. The existence of sodium minerals has been shown in a few Utah core holes;

TABLE A-2 Estimated In-Place Oil Shale Resources in the Southeastern Portion of the Uinta Basin Based on a Minimum Expected Yield of 25 gal/ton and a Minimum Thickness of 25 ft^a

Green River Formation	Acreage	Average Resource (bbl/acre)	Total In-Place Resource (million bbl)
<i>At depths <3,000 ft below the surface</i>			
Parachute Creek Member, Mahogany Zone	410,400	75,707	31,080
Total			31,080

^a 1 bbl shale oil = 42 gal.

Source: Trudell et al. (1973).

the extent of these minerals, however, has not been defined. The potential for conflicts between the development of sodium minerals and oil shale in the Green River Formation would need to be analyzed on a site-specific basis. The eastern Uinta Basin also contains significant deposits of the solid hydrocarbon gilsonite, which has been mined there for about 100 years and is processed and used in inks, paints, oil well drilling muds and cements, asphalt modifiers, and a wide variety of chemical products. These vertical gilsonite dikes strike between 40° and 70° west of north, have strike lengths ranging from less than 1 mi to nearly 14 mi, range in width from a fraction of 1 in. up to 18 ft, and are generally found in the strata above the Green River Formation (Verbeek and Grout 1992). Conflicts may exist between the existing development of gilsonite and the future development of oil shale in the Uinta Basin.

A.1.4 Green River and Washakie Basins

The Eocene Green River Formation of southwestern Wyoming was deposited in Lake Gosiute, which occupied parts of the present-day Green River, Fossil Butte, Bridger, Great Divide, Washakie, and Sand Wash Basins, which are referred to here as the Green River and Washakie Basins, as shown in Figure A-1. Lake Gosiute existed for about 4 to 8 million years during Eocene time. The lake history is characterized by two major high-water stands separated by a low-water stand; these correspond to the Tipton, Wilkins Peak, and Laney Members of the Green River Formation (Bradley 1964).

Lake Gosiute formed in a basin bounded by uplifted Precambrian, Paleozoic, and Mesozoic rocks that were uplifted to form mountains rising to about 6,500 ft above MSL (Bradley 1963). Initially, several thousand feet of fluvial sediments were deposited in the basin during the Paleocene and early Eocene. These deposits constitute the main body of the Wasatch Formation, which probably accumulated on a fairly featureless alluvial plain. Continued down-warping of the basin relative to surrounding mountains caused the area to become poorly drained, and Lake Gosiute formed in the center of the basin, gradually expanding to an area of several thousand square miles (Bradley 1964). The lacustrine Green River Formation was deposited in the central part of the basin and the fluvial Wasatch Formation along the basin

margins. The two formations interfinger in such a way as to demonstrate three major stages in the history of Lake Gosiute. The lower Tipton Member of the Green River Formation was deposited during a high stand, when a large, relatively freshwater lake occupied the Basin (Bradley 1964; Wolfbauer 1971). The overlying Wilkins Peak Member, however, accumulated in a playa-lake complex that occupied a much smaller area (Eugster and Surdam 1973; Bradley 1973; Eugster and Hardie 1975). The lake expanded following Wilkins Peak time, and the Laney Member of the Green River Formation was deposited during this high-water stand (Surdam and Stanley 1979). Lake Gosiute occupied the basin for several million years during the early and middle Eocene, and the Laney stage of the lake may have lasted about 1 million years on the basis of potassium/argon dating of tuff beds in the Wilkins Peak and Laney reported by Mauger (1977). Subsequently, this basin was deformed into the Bridger, Washakie, Great Divide, and Sand Wash Basins by post-middle and pre-late Eocene uplifts (Pipiringos 1961).

Additional oil shale resources are also found in the Washakie Basin east of the Green River Basin. Trudell et al. (1973) report that several members of the Green River Formation on Kinney Rim on the west side of the Washakie Basin contain sequences of low- to moderate-grade oil shale. Two sequences of oil shale in the Laney Member, 36 and 138 ft thick, average 17 gal/ton and represent as much as 67,908 bbl/acre of in-place shale oil. A total estimate of the resource in the Washakie Basin was not reported for lack of subsurface data.

In general, Wyoming oil shales tend to be thin and of only moderate quality. The oil shale beds tend to be almost flat, and each bed shows the same basic characteristics throughout most of the deposit. Most of the known Wyoming deposits of higher-grade oil shale occur in the Green River Basin and are estimated to contain 30 billion bbl of shale oil. Leaner shales exist over a wider area, including the entire Washakie Basin. Overburden depth ranges from 400 to 3,500 ft. Trona and halite are associated with or adjacent to the shallow oil shale deposits in the Green River Basin of Wyoming; however, the amount and extent of dawsonite and other saline minerals have not been established. Tables A-3 and A-4 show estimated oil shale resources of the Green River and Washakie Basins, respectively.

The Wilkins Peak Member of the Green River Formation in the Green River Basin in southwestern Wyoming contains not only oil shale but also the world's largest known resource of natural sodium carbonate, known as trona. The trona resource is estimated at more than 115 billion tons in 22 beds ranging from 4 to 32 ft in thickness (Wiig et al. 1995). In 1997, trona production from five mines was 16.5 million tons (Harris 1997). Trona is refined into soda ash, which is used in the manufacture of bottle and flat glass, baking soda, soap and detergents, waste treatment chemicals, and many other industrial chemicals. One ton of soda ash is obtained from about 2 tons of trona ore. Wyoming trona supplies about 90% of U.S. soda ash needs. About one-third of the Wyoming soda ash is exported. Natural gas is also present in the Green River oil shale deposits in southwestern Wyoming, but in unknown quantities.

A.2 HISTORY OF OIL SHALE DEVELOPMENT

The worldwide history of oil shale applications reaches far back in time. For example, Speight (1990) reports that oil shales were sources of fuel as early as 800 A.D., oil shale deposits

TABLE A-3 Estimated In-Place Oil Shale Resources in the Green River Basin Based on a Minimum Expected Yield of 15 gal/ton and a Minimum Thickness of 15 ft^{a,b}

Formation	Acreage ^c	Average Resource (bbl/acre)	Total In-Place Resource (million bbl)
<i>At depths ≤500 ft below the surface</i>			
Laney Member	147,085	59,912	8,812
Wilkins Peak Member	248,003	163,515	40,552
Tipton Member	54,247	100,346	5,443
Total			54,808
<i>At depths >500 ft and <3,000 ft below the surface</i>			
Laney Member	670,730	87,725	58,840
Wilkins Peak Member	1,105,165	144,943	160,185
Tipton Member	1,066,047	138,222	147,351
Total			366,377

^a 1 bbl shale oil = 42 gal.

^b Totals may be off because of rounding.

^c Total acreages shown do not account for overlap of the classifiable oil shale zones among the different formation members.

Source: Wiig (2006c).

in what is now the British Isles were worked during Phoenician times, and applications of oil shale as fuel in Austria have been recorded as early as 1350 A.D. Commercial production of shale oil as a fuel is said to have begun in France in 1838 (Kilburn 1976; Speight 1990).

In the United States, use of oil shale as a fuel is reported to have occurred in the 1800s. The first retort for processing oil shale in the United States is reported to have been constructed in 1917 near Debeque, Colorado (Kilburn 1976). Mining and processing of oil shale occurred in Elko, Nevada, as early as 1921 when the Catlin Oil Company attempted to distill organic materials from oil shale with the aid of water from nearby hot mineral springs (Garside and Schilling 1979). In collaboration with Shell Oil Company, Fishell developed a detailed chronology of oil shale development in western Colorado (interested readers should refer to Fishell and Shell Oil Company 2003). A history of the Federal Prototype Oil Shale Leasing Program is provided in a report published by the U.S. Congress Office of Technology Assessment (OTA) (1980a). The establishment of the U.S. Naval Oil Shale Reserve by the U.S. Government was likely the inaugural event in oil shale's more formally directed and extensively documented developmental history.

The history of the development of oil shale as a commercial fuel in the United States is characterized by boom and bust cycles, tied most directly in time to the availability of economical supplies of conventional crude oil, both foreign and domestic. The period immediately following the Arab Oil Embargo of 1973 is generally considered to be the period of

TABLE A-4 Estimated In-Place Oil Shale Resources in the Washakie Basin Based on a Minimum Expected Yield of 15 gal/ton and a Minimum Thickness of 15 ft^{a,b}

Formation	Acreage ^c	Average Resource (bbl/acre)	Total In-Place Resource (million bbl)
<i>At depths ≤500 ft below the surface</i>			
Laney Member	25,218	177,179	4,468
Wilkins Peak Member	0	0	0
Tipton Member	4,086	31,681	129
Luman Tongue	13,636	188,067	2,564
Total			7,162
<i>At depths >500 ft and <3,000 ft below the surface</i>			
Laney Member	184,137	232,802	42,867
Wilkins Peak Member	2,893	21,504	62
Tipton Member	46,189	36,419	1,682
Luman Tongue	52,388	68,199	3,573
Total			48,184

^a 1 bbl shale oil = 42 gal.

^b Totals may be off because of rounding.

^c Total acreages shown do not account for overlap of the classifiable oil shale zones among the different formation members.

Source: Wiig (2006c).

most intense interest in oil shale and the period during which the majority of technological advancements took place. During this period, numerous projects were undertaken, most occurring on government land with government involvement in both technical direction and subsidy. When the price and availability of conventional crude oil stabilized around 1982, interest in oil shale development dropped precipitously and, with the exception of a few minor research ventures, all field activities of a commercial nature, and most complementary technology developments, virtually ceased.

During and immediately after this intense period of oil shale RD&D, numerous comprehensive technology evaluations were published, either as progress reports for individual government-sponsored projects or as overviews of the industry sector in general. Environmental, economic, engineering, and social footprints were exhaustively defined. Operating data from pilot plants and laboratory simulation studies were extrapolated to characterize and compute the environmental impacts that could be expected from the most probable types and scales of future commercial oil shale ventures. Complementary investigations were conducted in laboratories on the chemistries of kerogen, the organic fraction of oil shale, and the products of its modification to produce conventional fuels through pyrolysis and upgrading activities. Thermodynamics, reaction mechanisms, and kinetics of kerogen pyrolysis were defined, and relationships between

conditions during pyrolysis and the chemical composition of the resulting “crude shale oil” were established.

With the introduction of mass production of automobiles and trucks in the United States in the early 1900s, a temporary shortage of gasoline encouraged the exploitation of oil shale deposits for transportation fuels. Many companies were formed to develop the oil shale deposits of the Green River Formation in the western United States, especially in Colorado. Thousands of oil placer claims were filed on public lands in the western United States. However, the discovery and development of large deposits of conventional oil in West Texas led to the demise of these early oil shale enterprises by the late 1920s (Dyner 2003).

In 1967, the DOI began an aggressive program to investigate the commercialization of the Green River Formation oil shale deposits. The dramatic increase in petroleum prices resulting from the Organization of Petroleum Exporting Countries (OPEC) oil embargo of 1973 triggered another resurgence of oil shale activities during the 1970s and into the early 1980s. In 1974, several parcels of public lands overlying oil shale resources in Colorado, Utah, and Wyoming were put up for competitive bid under the Federal Prototype Oil Shale Leasing Program. Under this program, oil companies leased four tracts on public lands (two in Colorado referred to as C-a and C-b and two in Utah referred to as U-a and U-b). In addition to these four federal projects, several projects were initiated on private lands. These projects are summarized below by state.

A.2.1 Colorado Activities

- ***Atlantic Richfield Company (ARCO), Ashland Oil, Shell Oil, and The Oil Shale Corporation (TOSCO)*** leased Tract C-b, in 1976, following the withdrawal of ARCO and TOSCO from the venture, Ashland and Shell submitted the first detailed development plan to the Oil Shale Project Office. It outlined a conventional underground room-and-pillar method of mining with surface retorting of the mined shale. In 1977, after a 1-year suspension to resolve technical issues, Shell had dropped out and Occidental Oil Shale, Inc. (OOSI) joined Ashland to develop the resource using OOSI’s modified in situ (MIS) process. The MIS method of oil shale mining deviated from the plan first described and offered enhanced recovery and a possible solution to some of the technical problems that formed the basis for suspension. Ashland withdrew from the project in April 1979 and Tenneco joined OOSI in September 1979 to form the Cathedral Bluffs Oil Shale Company (CBOSC). Tract operations began that year. Production, service, and ventilation/escape shafts were sunk to a depth of 1,969 ft, holding ponds were completed, and office facilities were constructed, along with a mine power substation, natural gas supply building, sewage treatment plant, and a manway and utility tunnels. In 1981, CBOSC announced a project reassessment, and major plan construction was put on hold. In 1983, CBOSC applied for and received financial assistance from the U.S. Synthetic Fuels Corporation (SFC), a government-funded entity established to foster development of an oil shale industry. A revised plan of development was submitted to produce 14,100 bbl

of shale oil per day. The detailed development plan proposed an underground room-and-pillar mine, an aboveground oil shale retort, mine and surface processing facilities, and an oil upgrading facility. None of this occurred, however. In 1984, SFC board members stepped down, and, as a result, no contract with SFC was secured. In 1985, CBOSC continued negotiations with SFC. At the same time, a bill was passed in the House to abolish SFC. A similar amendment in the Senate failed, 43 to 40. President Reagan signed Public Law 99-190, which provided, as part of overall appropriations, for the termination of SFC within 120 days, and the rescindment of all funds not yet committed. In 1986, negotiations for the suspension of the Tract C-b lease and shaft pumping cessation were initiated. The suspension was granted in 1987. Pumping on the production and maintenance shafts stopped in 1991, and the headframe was removed in 2002. No shale oil was ever produced from this federal lease.

- ***Occidental Oil Shale, Inc.***, used the Logan Wash facility as a testing site for the MIS process planned at Colorado lease Tract C-b and considered for Tract C-a. The 10-mi² site was purchased from private sources in 1972. Mining began in 1972, and by 1981, six retorts were developed and burned to produce a total of 94,500 bbl of shale oil. Initial in-situ retorts on the site consisted of three experimental-size operations, each producing 1,200 to 1,600 bbl of shale oil in total. Three considerably larger retorts, Retorts 7, 8, and 8x, were constructed at Logan Wash. Retorts 7 and 8 were fired and successfully produced nearly 58,300 bbl of shale oil from the 3-year, \$29 million program. About 450 people were employed at the Logan Wash site.
- ***Union Oil Company of California*** began acquiring oil shale properties in Colorado around 1921 in the Parachute Creek area of the Piceance Basin north of the town of Parachute in Garfield County, Colorado. Union owned the mineral rights under nearly 50 mi² of oil shale lands. From 1955 through 1958, Union built and operated a surface retort on its Colorado properties. The facility produced about 800 bbl of shale oil per day using a unique upflow retort process. More than 13,000 bbl of this shale oil were successfully processed into gasoline and other products at a Colorado refinery. However, low crude oil prices in the 1960s prevented further process development. With the rapid rise in price and uncertain availability of foreign crude oil in the early 1970s, Union reactivated R&D in its upflow retorting process. Continuing improvements were made in efficiency and product quality. In the fall of 1980, construction began on the first phase of Union's 50,000-bbl/day oil shale facility. The first phase of the project called for surface retorting of raw shale retrieved from a room-and-pillar mine. Union spent more than \$1.2 billion, with substantial financial assistance from the federal government. Union began production in 1984 but did not ship its first barrel of oil until December 1986. Union was able to produce shale oil and upgraded this shale oil to syn crude at its commercial oil shale production facility at the Parachute

Creek plant. Union began shipping synthetic crude from its Parachute Creek plant to a Chicago refinery and was producing about 6,000 to 7,000 bbl/day in 1989 at its peak production, sustained by a federal subsidy. The Parachute Creek plant had approximately 480 workers and 200 contract employees. The oil shale project was shut down in June 1991.

- ***The Exxon-TOSCO Colony Project*** was established in 1963 as a joint venture among Sohio, the Cleveland Cliff Iron Company, and TOSCO. Beginning in 1965, various companies acquired and sold an interest in the Colony Project, resulting by 1980 in ownership by Exxon Corporation (60%) and TOSCO (40%). The Colony Project controlled a 22-mi² resource block. Starting in 1964 and ending in the early 1970s, approximately 200,000 bbl of shale oil were produced experimentally at the TOSCO II Semi-Works Plant. In the 1960s, a prototype mine and plant operation proved the viability of the underground mining plan with aboveground processing using the “TOSCO II” retort method. Plans called for the mining of oil shale processed through pyrolysis and the upgrading of facilities. Design and engineering work for a commercial plant progressed through various stages. The underground mine was to be worked with room-and-pillar methods, proceeding with the conventional cycle of drilling, charging, blasting, wetting of rock piles, loading, hauling, scaling, and roof bolting. Run-of-mine shale was to be crushed to the desired retort feed size in two stages. Retorting and upgrading facilities would recover upgraded shale oil, ammonia (NH₃), sulfur, and coke from the crushed shale. Fuels produced for internal combustion would include treated fuel gas, a liquid carbon stream, fuel oil, and diesel fuel. The kerogen content of raw shale was to be converted into the above hydrocarbon vapors and liquids using six individual “TOSCO II” retorting trains. Upgrading included coking, gas recovery and treating, and hydrotreating. Exxon planned to invest up to \$5 billion in a planned 47,000-bbl/day 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. No shale oil was ever produced commercially.
- ***Gulf Oil Company and Standard Oil Company of Indiana*** leased Federal Prototype Oil Shale Tract C-a from the DOI for \$210.3 million. Tract C-a was the first federal tract to be leased as part of the DOI’s program to test the environmental and economic feasibility of oil shale development. Tract C-a was located in Rio Blanco County at the head of Yellow Creek on the western edge of the Piceance Creek Basin. Gulf and Standard later formed the Rio Blanco Oil Shale Company (RBOSC), a 50:50 general partnership, to develop the 5,100-acre tract. Originally, Tract C-a was to be developed as an open pit mine. However, the DOI did not make additional federal land available for off-tract disposal of processed shale and overburden. There were also air quality issues and other constraints with the pit mining concept. After a 1-year suspension of operations, RBOSC decided to develop the tract by underground MIS methods. In February 1979, the company purchased OOSI’s

MIS technology. In the commercial phase, plans called for shale oil to be transported to existing Gulf or Standard corporate refineries. Tract C-a was a one-level operating mine, with driftwork essentially completed for three underground demonstration retorts. A conventionally sunk production shaft, vent shaft, service shaft, and production shaft were built. Approximately 500 people were employed during the construction phase of this project. In October 1980, RBOSC ignited the first of three demonstration MIS retorts. The burn was scheduled to last 9 weeks. The demonstration retort was ignited at the top, some 670 ft below the earth's surface. This was the first burn in the company's \$140-million program to demonstrate commercial feasibility of the MIS technology; 1,750 bbl of oil were recovered from the first retort. Two additional burns were conducted in 1981, which recovered approximately 23,000 bbl of shale oil. The retorts were prematurely flooded in 1984 because of pump failure, and the company was unable to resume operations. Approximately 150 people were employed during the operational phase of this project.

- **TRW, Inc.**'s Naval Oil Shale Reserves (NOSR) Project was conducted under the direction of the Secretary of Energy and included three sections of land known as NOSR 1, 2, and 3. NOSR 1 and 3 were located in Colorado and NOSR 2 was located in Utah. In 1977, TRW was chosen to be the prime engineering and management contractor for the project, which involved performing a 5-year, \$62 million resource, technology, environmental, and socioeconomic assessment to advise DOE on what should be done with the NOSR. The TRW, Inc., team included Gulf Research and Development Company, TOSCO, C.F. Braun and Company, and Kaiser Engineers. The assessment was to be completed in 1984. In September of 1980, DOE released a draft EIS that discussed other fuel alternatives to oil shale and explored five NOSR development approaches ranging from leasing to industry to a government-owned facility. The report recommended that the biggest return to the federal government would be through production of the natural gas reserves.
- **Multi Minerals Corporation (MMC)**, a subsidiary of the Charter Company, signed an agreement in April 1979 to operate a U.S. Bureau of Mines research tract known as Horse Draw. MMC hoped to offset much of the expense of mining oil shale by recovering nahcolite and dawsonite, two potentially valuable minerals found within the shale. The company also hoped to prove that its Integrated In Situ recovery method was environmentally acceptable; this process reportedly did not produce spent shale residue on the surface, nor did it use or contaminate surface water. In 1977 and 1978, the U.S. Bureau of Mines opened an experimental mine that included a 2,370 ft-deep shaft with several room-and-pillar entries in the northern part of the Piceance Basin to conduct research on the deeper deposits of oil shale, which are commingled with nahcolite and dawsonite. Large-scale process testing began in mid-1981, when construction of the company's adiabatic retort in Grand Junction was

- completed. The company's experimental mining involved room-and-pillar mining in a bedded nahcolite and shale zone about 8 ft thick, averaging about 60% nahcolite. The shafts were used to obtain geologic and hydrologic data in the deeper end of the Piceance Basin. The site was closed in the late 1980s.
- ***Equity Oil Company and DOE*** launched a project known as the BX In Situ Oil Shale Project in 1977 to test a method of in situ retorting that frees the kerogen from the shale by injecting superheated steam into the permeable leached zone underlying a site owned by Equity, Exxon, and Atlantic Richfield southwest of Meeker in Rio Blanco County, Colorado. Project field tests began in June 1979 and continued for 2 years on a 1-acre site within the 1,000-acre tract owned by Equity and its partners. Steam injections for a sustained period began in June 1980. By August, the formation showed signs of continued and steady heating. By August 1981, 625,000 bbl of water-turned-steam had been injected into 8 project wells, and approximately 100 bbl of shale oil had been recovered. Equity's principle oil shale interest focused on the leached zone; the only zone in the Piceance Basin that has native permeability sufficient to initiate in situ recovery without fracturing or premining of bedrock. The injected steam process evolved from both laboratory and fieldwork begun in the 1960s. These tests used natural gas rather than steam. Laboratory results showed that the oil recovered was superior in quality to that produced in conventional surface retorts, possibly because of lower temperatures and the absence of any oxidizing gases. While evaluating the project in 1970, Equity determined that superheated steam could be used to lower costs. Beginning in April 1971, the BX project was converted to steam, and injections were performed almost continuously until the research project was suspended for financial reasons 4 months later. From this latest research, Equity determined that water from the leached zone may be used, thus eliminating the need to import water. Equity also found that a minimum amount of surface disruption results from the construction and operation of the process. With only minor alterations, the existing BX oil shale site was utilized for the reactivated program in 1977. Achieving the needed temperatures and pressures required a reasonably sophisticated steam-generating plant, water storage facilities, and an instrumentation system to monitor both equipment and project performance.
 - ***Chevron Shale Oil Company's (Chevron)*** historic involvement with oil shale in Colorado involves the work of three corporations: Chevron Corp, Texaco Inc., and Getty Oil Company. Texaco merged with Getty in 1984, and Chevron and Texaco merged in 2001. Properties were acquired by the companies beginning in the 1930s, and today the combined oil shale acreage totals about 100,000 acres in Mesa and Garfield Counties. The lands are managed by Chevron Shale Oil Company, a division of Chevron USA, Inc. Early work by Chevron was mainly resource evaluation and mapping. In the 1970s, Chevron and Texaco participated in a consortium of companies that supported the Paraho Oil Shale Project at the Anvil Points facility, west of

Rifle, Colorado. The surface retort produced more than 100,000 bbl of shale oil for the U.S. Navy. In 1981, Chevron Shale Oil Company and Conoco Shale Oil, Inc., began the Clear Creek project on a 25,000-acre tract of private land north of DeBeque. Chevron Shale Oil Company was the operator. The goal of the project was to produce 100,000 bbl of shale oil by the mid-1990s. The oil shale was to come from an underground mine, which started construction in 1981. The company developed a second-generation surface retorting process called the Staged Turbulent Bed at its Richmond, California, laboratory. Tests were made using a 1-ton/day and a 4-ton/day plant. The next phase was the Semi-Works Development Project. A 350-ton/day retort was constructed and successfully tested at the Chevron refinery near Salt Lake City, Utah. Crushed rock was moved to the retort by rail. A small amount of shale oil was produced, but because of the drop in oil prices, mine construction was halted in 1984. The commercial phase of the project was not reached, and the mine has remained closed.

A.2.2 Utah Activities

In Utah, six oil shale projects were planned that progressed to various stages of development. The six projects are described below (DOE 1981). From 1954 through 1990, several companies and governmental agencies drilled at least 200 oil shale exploration wells in the Uinta Basin and conducted Fischer assays on the oil shale core samples. In addition to the core samples, the USGS had an oil shale program from the late 1950s through the 1970s that collected cutting samples from more than 400 oil and gas wells penetrating the oil shale-bearing portion of the Green River Formation. Fischer assays also were conducted on those samples. Data on the thickness, depth, and Fischer assay information exist for the oil shale interval in the Parachute Creek Member of the Green River Formation from more than 600 wells spread across the Uinta Basin, but mainly from the southeastern quarter of the basin.

- **Geokinetics, Inc.**, was originally organized in 1969 as a minerals development company; it was reorganized in 1972 as a joint venture with a group of independent oil companies to develop an in situ technique to extract shale oil. The company began design and cost studies of a horizontal modified in situ process in preparation for the anticipated Federal Prototype Oil Shale Lease Program sale. Small-scale pilot tests in steel retorts were carried out to simulate the horizontal process in 1974 and early 1975. Starting in April 1975, field tests of the in situ method were carried out, and by late 1976 the basic parameters for an in situ process were established. From 1977 through 1979, the process was scaled up substantially from early tests, and rock-breaking designs for the underground retorts were improved and tested. From 1980 through 1982, Geokinetics, funded in part by DOE, blasted 24 experimental underground retorts and tested them. These tests cumulatively produced 15,000 bbl of oil. By 1982, the company had settled on a 2,000-bbl/day design for its commercial retort and had acquired 30,000 acres of nonfederal leases, with an estimated resource of 1.7 million bbl of oil (averaging 20 gal/ton).

Between 1972 and 1982, the company drilled at least 32 core holes on its leases in the Uinta Basin and conducted Fischer assays on oil shale samples from those wells.

- ***Magic Circle Energy Corporation*** acquired the 76,000 acres of State of Utah leases composing the Cottonwood Wash properties from the Western Oil Shale Corporation in July 1980 through an exchange of stock. The Cottonwood Wash properties contained an estimated 2.1 billion bbl of oil with a grade in excess of 15 gal/ton, and at a depth between 1,500 and 2,000 ft. Magic Circle spent more than \$1 million to perform feasibility studies, initiate permit applications, and perform initial coring for resource definition, mine design, and environmental evaluation, but no mine or plant construction or oil shale production took place on this project.
- ***Paraho Development Corporation*** was organized in Grand Junction, Colorado, in 1971, to develop oil shale technology. The company acquired leases along the White River in Utah near the border with Colorado, but no work was performed on the property. The company conducted several retort research projects in Colorado with several other industry partners to achieve an oil recovery averaging 90% of the in-place oil. On the basis of this research, the company was contracted by DOE to produce 100,000 bbl of shale oil. Paraho used the Anvil Points facility to conduct a 105-day continuous-stream operation in the late 1970s that produced the contracted amount of shale oil with 96% oil yields. The oil market deteriorated before a commercial plant could be permitted and built on the Utah leases.
- ***Syntana-Utah*** was a joint venture of the Synthetic Oil Corporation and Quintana Minerals Corporation that was formed in late 1980. This venture acquired a State of Utah lease on Section 16, T9S, R25E, on which it planned to construct an underground mine and surface retort operation that could produce 24,500 tons/day of 25 gal/ton oil shale. Limited effort was spent identifying the depth, thickness, and grade of the oil shale to quantify the oil shale resource on the lease. Two, and perhaps more, drill holes were completed on the property to facilitate mine and retort engineering design.
- ***TOSCO Development Corporation*** acquired 29 separate State of Utah oil shale leases totalling 14,688 acres of land about 35 mi south of Vernal, Utah. These leases were generally located in T9S and T10S, and R21E and R22E. Between 1977 and 1981, TOSCO drilled eight or more core holes to help define the oil shale resource and to initiate basic actions leading to a site-specific EIS for a 66,000-ton/day mine with a production capacity of 47,000 bbl/day employing multiple TOSCO II retort facilities. Subsequent deterioration of oil prices led to the cancellation of the project before final permitting and construction began.

- **White River Shale Oil Corporation (WRSOC)** was a joint venture of three major oil companies: Phillips, Sohio, and Sunoco. Sunoco and Phillips were the successful bidders for the 5,120 acres composing the U-a federal lease tract that sold for \$75.6 million at the 1974 Federal Prototype Oil Shale Lease Program sale. Shortly after the first sale, Sohio joined the venture and the WRSOC was formed. In 1975, the group paid an additional \$45.1 million and acquired the 5,120-acre U-b tract that was adjacent to the U-a tract. Between 1974 and 1976, the WRSOC drilled 18 wells on its leases and created a detailed development plan that was submitted to the federal government in mid-1976. The development plan called for a 179,000-ton/day mine that would be supported by a 100,000-bbl/day surface retort at full commercial operation. Later that year, the leases were suspended because of environmental and land title issues and remained suspended until the early 1980s. Once these issues were resolved, the venture ultimately constructed mine service buildings, water and sewage treatment plants, and a 1,000-ft-deep vertical shaft and inclined haulage way to the high-grade Mahogany Zone of oil shale. Several tens of thousands of tons of oil shale were extracted to test mining conditions and retort technology and economics. The project was abandoned before commercial operations were achieved when market conditions deteriorated in the mid-1980s.

Although the six Utah oil shale projects reached various stages of completion during the late 1970s and 1980s, none were able to reach commercial operation. Both mining with surface retort and in situ recovery methods of shale oil were investigated in Utah. The legacy of the surge of interest in oil shale development in the late 1970s and early 1980s is a wealth of resource, engineering, and baseline environmental data that will be useful in future efforts to develop oil shale resources.

A.3 TECHNOLOGY OVERVIEW

With the cessation of commercial development, there have been some minor evolutionary changes to oil shale development technologies, but some ongoing research has the potential of precipitating major revolutionary changes in oil shale development technologies. Notwithstanding these recent research initiatives, the technology evaluations conducted at the end of the zenith of oil shale development activities are still largely valid, despite the majority of them being produced more than 20 years ago. The few technology evaluation updates that have been published in more recent years rely primarily on the data and conclusions from those original evaluations and are unique only to the extent that they incorporate the results of the few ongoing research projects and anticipate the technology transfers that would likely be made from other mining and energy sectors. The information provided in this section brings forward the most relevant data and conclusions from the most comprehensive and reliable previous reviews.

Development of oil shale resources fundamentally occurs in three major steps: (1) recovery or extraction from the natural setting, (2) processing to separate organic and inorganic constituents, and (3) upgrading the organic components in anticipation of further

refining into conventional fuels. The physical and chemical features of oil shale deposits and other circumstantial factors associated with their deposition compose the economic and engineering parameters that dictate the most appropriate development schemes. Typical development schemes always involve each of the above major steps, although many permutations of these steps are possible and many interim steps may also be necessary. This appendix provides descriptions of each of these major actions, the technologies that have been developed for each, their advantages and disadvantages, and their potentials for environmental impact.

A.3.1 Recovery of Oil Shale

A variety of technologies have been developed and commercially applied to oil shale recovery or extraction, and others are in the R&D phase. Other technologies that have proven their worth in other mining industry sectors conceptually apply to oil shale, but have yet to be applied at commercial scales. Efforts to recover oil shale resources have the potential to be both the most energy intensive and most environmentally problematic steps of oil shale development; advancements in recovery technologies ensure that greater portions of resources will be economically recoverable, operating costs will be minimized, and recovery efficiencies will be maximized. Resource extraction techniques can be generally categorized as direct or indirect recovery. Direct recovery involves the removal of the oil shale from its formation for ex situ processing. Indirect or in situ recovery involves some degree of processing of the oil shale while it is still in its natural depositional setting, leading ultimately to the removal or extraction of just the desired organic fraction. Additional aboveground processing of that fraction is still typically required.

A.3.1.1 Direct Recovery Mining Technologies

Surface mining techniques (e.g., strip mining and/or pit mining) as well as subsurface mining techniques (e.g., room-and-pillar mining, longwall mining, and other derivatives) have been successfully employed in the recovery of oil shale. For oil shale deposits relatively close to the surface, conventional strip mining technologies could be employed to retrieve the oil shale. As discussed in Section A.1, the BLM has limited its evaluation of the impacts of surface mining for oil shale to areas within the most geologically prospective oil shale areas where the overburden ranges in thickness from 0 to 500 ft. The areas where the overburden is 0 to 500 ft that potentially will be made available for application for leasing using surface mining technologies are limited to part of the Uinta Basin in Utah and parts of the Green River and Washakie Basins in Wyoming (Figure A-1). Surface mining will not be considered in Colorado because the distribution of areas where the overburden thickness is less than 500 ft is dispersed enough as to make it difficult to assemble a logical mining unit. In Utah, about 133,194 acres of land within the most geologically prospective oil shale area have an overburden thickness of 0 to 500 ft. In Wyoming, the corresponding area includes about 380,220 acres.

Conventional strip mining techniques and equipment developed in other mining industry sectors, primarily coal, can be applied directly to strip mining of near-surface oil shale deposits.

Most oil shale deposits have distinct bedding planes. Experience has shown that shear strengths along these bedding planes are substantially less than across the planes, thereby ensuring that, in many instances, strip mining techniques using draglines and/or shovels will be successful without additional efforts to fracture the formation (e.g., through the use of explosives) (DOE 2004a).⁵ However, enhancement of natural fractures through the use of explosives (typically ammonium nitrate/fuel oil mixtures) or high-pressure water injection (hydrofracturing) is still commonly employed in strip mining operations. Depending on the formation thickness, strip mining may proceed through excavation of a series of “benches,” each 30 to 50 ft deep.

Both strip mining and pit mining can be successfully applied to near-surface deposits with generally flat formation orientations. Both methods use similar types of equipment: shovels, bucket-wheel excavators, draglines, conveyors, trucks, scrapers, etc. The most probable combination of mining equipment would involve diesel-powered shovels loading materials into haul trucks ranging in size from 240- to 400-ton capacity.

Pit mining does not typically require any ventilation or special considerations for the presence of methane (CH₄); it does, however, typically utilize explosives to rubblize the formation before removal. Both surface mining methods impact significant land areas. Both require separate areas for temporary storage of overburden. Strip mines are often developed in such a manner that previously evacuated areas can be used to receive processing waste (retort ash); however, operations involving pit mines must utilize a separate area for retort ash disposal.

According to Nowacki (1981), technological benefits of surface mining can include:

- Low cost (over the life of the operation) and high productivity relative to other mining techniques;
- Flexibility to adjust to changes in formation geometries;
- High production tonnages (i.e., high resource recovery efficiencies);
- Previously mined areas that provide storage areas for future overburdens or disposal areas for spent shale; and
- Technologies that are well established, and operating logistics that have been optimized.

However, environmental impacts can be significant, including:

- Substantial land areas disturbed, loss of habitat (both at the working face and at stockpile areas);
- Substantial amounts of overburden and spent shale requiring management;

⁵ This same engineering feature of low shear strength in the bedding planes can also preempt the successful application of room-and-pillar mining techniques.

- Potential for ground and surface water impacts (pollution as well as altered drainage patterns);
- Potential for air quality impacts from fugitive dust as well as from operation of equipment, much of which utilizes internal combustion engines;
- Noise impacts from equipment vehicle operations, especially crushing and grinding operations and the use of explosives to loosen materials before removal (when necessary);
- Initial capital investment that may be high (necessarily very large mining/haulage equipment) to ensure high productivity; and
- Land reclamation programs that may extend well beyond cessation of mining operations (adapted from Nowacki 1981).

Although surface mining techniques are well established and may be the most economical, they are accompanied by significant environmental impacts to the land and groundwater and surface waters and the ecosystems that rely on them, as well as impacts to visual resources (Nowacki 1981). Consequently, while these extraction techniques were among the first investigated for oil shale development, they quickly fell out of favor by 1977 in deference to subsurface mining or in situ recovery techniques for resource extraction, and only a handful of field tests or large-scale operations were actually conducted by utilizing surface mining techniques (Nowacki 1981). All but one of the projects under consideration as part of the BLM's oil shale RD&D program (see Section A.5.3) focus on in situ processing rather than surface extraction and ex situ processing, suggesting that surface mining has a lower likelihood of being part of future development proposals.

For deeper deposits where surface mining is infeasible or prohibitively expensive, or for deep deposits that are accessible through outcrops along erosion faces, room-and-pillar mining techniques such as those used in coal mining have been successfully applied. The typical cycle of activities in room-and-pillar mining involves drilling, charging, blasting, wetting, crushing, loading, hauling, scaling, and roof bolting (DOE 1982).

Ventilation is necessarily continuous in virtually all room-and-pillar mining operations to provide for worker safety and is essential in "gassy" mines where explosive methane gas is present at concentrations greater than 1%. The excavated rooms are typically 60 ft wide by 90 ft high. Pillars (undisturbed formations) are 30 to 45 ft thick, depending on the engineering parameters of the particular formation and structural support demands dictated by the amount and type of overburden. In general, as much as 75% of the shale can be recovered by using this technique, especially in shallower formations (DOE 1982). Access to the mine is either by shaft, decline, adit, or a combination thereof.

Infrastructure necessary to support underground mining includes systems for both process and potable water, conveyor systems, crushing systems, and haulage systems. Mixtures of ammonium nitrate and fuel oil are typically used to rubblize the formation prior to crushing.

Typically, primary and even secondary crushing are conducted within the mine before oil shale is brought to the surface. Pumping systems to manage formation water are also typically present. Electric power and vehicle/equipment fuels (typically diesel) are also required. A variation on this technique, chamber-and-pillar mining, has also been advanced. In chamber-and-pillar mining, chambers are cut perpendicular to the main entry shaft. This technique offers particular advantages to oil shale mining in that the chamber heights can be variable, in accordance with formation geometries, and, once excavated, the chamber may serve as a convenient disposal area for spent oil shale. Essentially the same types of support equipment are required for chamber-and-pillar mining as for room-and-pillar mining.

A.3.1.2 Indirect or In Situ Recovery Techniques

Much attention has been paid to the development of in situ or indirect retrieval or extraction techniques in which just the kerogen fraction is actually recovered from the formation. Under normal conditions of temperature and pressure in the formation, kerogen is immobile. This fact is irrelevant and even beneficial if direct recovery techniques are employed. However, it becomes the most significant limiting factor when direct recovery is not possible or economical. To address these limitations, numerous indirect recovery techniques have been developed. In its simplest manifestation, an indirect recovery technique causes decomposition of kerogen to liquid and gaseous organic fractions of value that have sufficient mobility to “flow” through the formation for removal by conventional oil and gas recovery techniques. The two primary indirect recovery techniques, true in situ recovery (TIS) and MIS, both transfer heat to the formation; they differ, however, in the actions that are taken before formation heating is attempted. TIS involves introducing heat without prior efforts to significantly alter the formation’s permeability. MIS involves first altering the natural formation by increasing the extent of formation fracturing, thus theoretically improving the efficiency of formation heating and facilitating the movement of mobilized kerogen to points of retrieval.

For any in situ process, some minimal amount of formation disturbance is required to provide a path through which to introduce the heat source and through which kerogen decomposition products can flow to points of recovery. For TIS, such intrusions are minimal and typically involve no more than installing a collection of conventionally sized wells.⁶ Heat can then be introduced into the formation by a variety of mechanisms, sometimes by injection of steam or other materials into either vertically or horizontally oriented boreholes or wells, but also by the application of alternative energy technologies such as microwave heating, radio-frequency (RF) heating, or electric resistance heating. Typically, the same pathways into the formation by which heat is introduced are used to recover the heated, mobilized kerogen by using conventional liquid extraction technologies.

Intrusion into and alteration of the formation are somewhat greater for MIS techniques. Typically, explosives are introduced to enhance the degree of natural fracturing, thus facilitating

⁶ However, depending on the natural degree of fracturing, the permeability of the formation may still need to be enhanced through the use of explosives or by hydrofracturing. Even when these steps are taken, the extraction technique may still be called TIS.

the flow of kerogen decomposition products to points of extraction. Subsequently, anywhere from 10 to 30% (by volume) of the formation is mined by conventional techniques (and later processed above ground) to create voids in the formation that serve as retorting chambers from which the formation is heated and at or near which the mobilized kerogen is accumulated and extracted. First-generation in situ heating technologies were designed to mobilize the kerogen in the formation by reducing its viscosity while not changing its chemical composition. However, the majority of investigations into in situ heating technologies focused not only on the mobilization of kerogen, but also its pyrolysis. Such in situ pyrolysis techniques are discussed in Section C.3.2.

Enhanced oil recovery (EOR) technologies developed for the conventional crude oil and tar sands industries also have potential application to oil shale recovery. Both secondary and tertiary techniques have been developed. Secondary techniques essentially involve mechanical displacement of oil by the use of high-pressure immiscible gases or water. Waterflooding and high-pressure gas flooding are examples. Tertiary EOR techniques can be grouped into two categories: miscible techniques and thermal techniques. Miscible techniques involve the introduction of materials that dissolve the oil, increasing its ability to move through the formation to a recovery well. Thermal techniques introduce heat, lowering the oil's viscosity, thus facilitating its movement through the formation. Solvent flooding may involve the use of such materials as raw naphtha, a collection of light molecular weight aliphatic hydrocarbons, that is a principal feedstock for gasoline or other products of partial crude oil refining. Tertiary techniques often follow or are superimposed upon secondary techniques. For example, the injection of high-pressure steam combines a secondary displacement technique with a tertiary thermal technique. Many of these techniques have also been successful in enhancing the recovery of bitumen⁷ from tar sands. While most of these techniques are typically applied near the end of the useful life of a conventional crude oil deposit, they can be used for dislodging or mobilizing kerogen in the early phases of formation development, either alone or in conjunction with the conventional heating technologies discussed above. Overviews of some of the most promising EOR technologies are provided below. More detailed discussions of EORs can be found in *Enhanced Oil Recovery; Secondary and Tertiary Methods* (Schumacher 1978) or any of the numerous other technical publications on these technologies.

- ***Steam Injection Technologies.*** Steam injection has been used for decades to enhance recovery of crude oil or to mobilize heavy oils for retrieval. One such technology adapted to recovery of bitumen from tar sand, cyclic steam stimulation (CSS), may be applicable to oil shale recovery. CSS involves the injection of steam at high pressure and temperature into the deposit, causing the oil sand to fracture, simultaneously lowering the viscosity of the bitumen as it absorbs heat from the steam. The fluidized bitumen is then recovered by strategically placed conventional liquid recovery wells, together with steam condensates. Steam injections are repeated over time until all of the bitumen is recovered.

⁷ Bitumen is the name commonly given to the organic fraction present in tar sands. Chemically it is a member of the asphaltene fraction of conventional crude oil.

A second widely used steam injection technology, steam-assisted gravity drainage (SAGD), is being used for retrieval of bitumen from tar sands in the vast deposits occurring in Alberta and Saskatchewan Provinces in Canada. SAGD is closely related to CSS in its technological approach; however, its mechanisms for recovery of mobilized/liquefied resources are unique. SAGD consists of two horizontal wells, a production well near the bottom of the formation and a steam injection well approximately 6 m above and aligned with the production well. Steam is circulated between the two wells, causing heating of the intervening formation by conduction. Once communication is achieved, the steam rises in the formation because of its relatively light density, heating the formation above the injection well. The heated oil, steam condensate, and formation water are then collected in the production well.

- **Waterflooding.** As the name implies, waterflooding involves the injection of water at high pressure to mechanically displace oil from rock pores and fissures. The process can also enhance formation permeability by hydrofracturing (or hydraulic fracturing), causing additional fractures in the formation through increases in hydrostatic pressure. Waterflooding and hydrofracturing are relatively inexpensive but require extensive amounts of water.
- **High-Pressure CO₂ Flooding.** This technology applies carbon dioxide (CO₂) at high pressures as a follow-on to in situ retorting and has two distinct advantages: displacement and removal of additional kerogen decomposition products not recoverable through conventional mining techniques or in situ heating techniques, and the possible sequestration of CO₂ released from the operation of various combustion sources to produce process steam or power. One of the potential large environmental impacts from oil shale development is the release of copious amounts of CO₂ during retorting and/or formation heating. Carbon dioxide has been used successfully in crude oil production as an effective enhanced recovery technique. After displacing crude oil from rock pores, the CO₂ is bound indefinitely within those pores. Such sequestration may therefore be a valuable pollution control mechanism for oil shale development, while at the same time improving kerogen recovery efficiencies.
- **Solvent Flooding.** Solvent flooding technologies are similar to steam injection technologies, substituting solvents for steam and relying on chemical dissolution of the kerogen rather than liquefaction through use of steam. Various organic solvents can be used. Solvent flooding is often performed with two horizontally oriented wells: an upper well into which the solvent is injected, and a lower well from which kerogen, diluted with solvent, and, in some cases, partially upgraded, can be recovered. Other well combinations for solvent injection and product recovery have also proven successful. Solvent injection offers a number of important benefits over steam injection: (1) little to no processing water is required; (2) the technique involves lower capital

costs since steam does not need to be produced, recovered, and recycled; (3) the solvent and potentially higher organic recovery rates are possible; and (4) partial upgrading of the kerogen may result from its interactions with the solvents selected. However, solvent injection also has some drawbacks. The solvent must be recoverable for the process to be economically viable, and any solvent not recovered represents a potential for groundwater contamination.

- ***Electromagnetic Heating.*** Another family of technologies accomplishes formation heating through the application of electromagnetic energy. Electromagnetic energy at relatively low power levels was initially developed for formation imaging, relying on the different resistivities of rocks, formation water, and oil being observable as they absorb induced energies. At higher levels of applied power, electromagnetic energy can be used to heat the formation. Energies throughout the energy spectrum can be used—low-frequency electric resistive heating to higher-frequency radio-wave and microwave heating. Electromagnetic heating technologies have potential applicability in those formations where more common steam injection technologies have limited success (e.g., low permeability formations, thin or highly heterogeneous formations, or especially deep formations) and may have an advantage in terms of delivering heat to greater depths in the formation. Electromagnetic heating is also particularly effective in reducing the viscosity of the organic phase; thus, it is especially applicable to the recovery of bitumen from tar sands and kerogen from oil shales, either as the primary technology or as a source of formation heating used in conjunction with, or prior to, other recovery technologies. The rates at which a formation must be heated by any of these technologies vary with formation characteristics, but typically the process can be expected to take 6 months to years of constant application of electromagnetic heating to create a sufficient temperature rise in the formation to dramatically increase organic retrieval efficiencies.

Raytheon has successfully developed a RF heating technology for application to oil shale recovery (Cogliandro 2006; see also Raytheon 2006). Field experience indicates that this technology results in rapid heating and volatilization of water, which, in turn, results in microfracturing of the formation, enhancing formation permeability and product recovery. Consequently, no preliminary steps designed to remove the majority of free formation water are necessary. Experience to date indicates that the Raytheon RF heating technique could be successfully applied to exploit formations with as little as 150 ft of overburden (the minimum thickness needed to prevent “bleeding” of induced RF energy at the surface). Applying the RF heating technique, Raytheon has obtained recovery rates of 75% of the oil shale’s Fisher assay value. Some upgrading of initial kerogen pyrolysis products has also been observed. However, in its latest form, the Raytheon RF heating

Carbon Dioxide Sequestration and Its Role in Oil Shale Development

Carbon sequestration is the isolation of carbon dioxide (CO₂) from the biosphere in what are called “natural carbon sinks.” The primary “sinks” are the oceans and growing vegetation that consumes CO₂ by the process of photosynthesis. However, sequestration of CO₂ in underground rock formations is also possible. In geological sequestration, the CO₂ can be effectively held in small pore spaces in mineral deposits for millions of years. Injecting CO₂ under high pressure into mature crude oil formations, a process known as CO₂ flooding, has long been employed as an enhanced oil recovery (EOR) technique to enhance crude oil recovery capabilities in mature fields. In CO₂ flooding, it is believed that the CO₂ displaces crude oil from mineral pore spaces into formation fractures where it is more easily recoverable. A February 2006 initiative launched by the U.S. Department of Energy’s (DOE’s) Office of Fossil Energy is specifically aimed at research into the use of CO₂ to enhance domestic oil and gas recovery and simultaneous CO₂ sequestration (see the Web site below). A similar mechanism of kerogen displacement is possible for oil shale formations, many of which are naturally fractured to equal or greater extent than typical crude oil-bearing rock formations.

In addition to a simple mechanical “trapping” of CO₂ in mineral pores, scientists believe that in some formations, a chemical reaction called “carbonation” occurs, converting the CO₂ to thermodynamically stable carbonates, ensuring that the sequestration is virtually permanent. Such reactions are actually acid-base neutralizations; thus, minerals containing alkali or alkaline earth metals are most inclined to engage in carbonation. Natural reaction kinetics of such carbonations are slow, however, so such reactions must be artificially encouraged by the introduction of heat and or pressure before becoming effective CO₂ control mechanisms. In addition to their thermodynamic stability, the carbonates formed are relatively insoluble to ground or surface waters with typical pH values. Thus, the carbonates are relatively immobile and unreactive in the environment; therefore, the CO₂ sequestration is not easily reversed. There is a substantial amount of research ongoing on carbon sequestration. The following Web sites and the links therein are recommended for further study: DOE-sponsored Carbon Sequestration research: <http://cdiac2.esd.ornl.gov/>. DOE’s Carbon Dioxide Sequestration Initiative (February 2006): http://www.netl.doe.gov/publications/press/2006/06008-EOR_Sequestration_Initiative.html. Carbon Capture and Sequestration Technologies at MIT: <http://sequestration.mit.edu/>. The North American Carbon Program: <http://www.nacarbon.org/nacp/agencies.html>. The following literature review and the references therein on the mechanisms of CO₂ sequestration in minerals are also recommended: <http://www.ecn.nl/docs/library/report/2003/c03016.pdf>.

technique is intended to be used in conjunction with the injection of supercritical CO₂ to enhance product recovery. Coupling those technologies has resulted in recovery rates as high as 90 to 95%.⁸

- **Chemically Assisted Recovery Techniques.** Various chemicals have been used successfully to enhance the recovery of crude oils. The chemicals selected perform various functions, acting as surfactants, electrolytes, mobility

⁸ See http://www.Raytheon.com/newsroom/feature/oil_shale06/.

buffers, diluents, or blocking agents that effectively block exchange sites in the formation for which oil molecules have an affinity. The selection of chemicals is based on a number of factors, including cost and availability of the chemicals, compatibility of the chemical with the formation, and various other logistical factors. Chemicals such as hydrazine and hydrogen peroxide have been used to initiate thermal recovery, while quinoline, sodium hydroxide, and toluene have been used to enhance thermal recovery initiated by other means (Schumacher 1978).

Experience using chemicals to enhance kerogen recovery is much more limited than it is for crude oils, but some of the concepts on which these chemically enhanced recovery technologies are based may be relevant to oil shale recovery. DOE-sponsored research carried out at Argonne National Laboratory investigated the specific manner in which kerogen molecules were bound to minerals in oil shale. Understanding the nature of this bonding would allow development of chemically enhanced recovery methods, since chemical attack of such bonds would, in theory, release the kerogen (Vandegrift et al. 1980). Follow-up investigations at the University of Colorado, Boulder, conducted laboratory-scale recovery of kerogen using solutions of 10% hydrogen chloride, 80% steam, and 10% CO₂ injected into shale samples at moderate pressures (Ramirez 1989). Some of the results were promising, producing yields of 80% and, in one instance, better than 90% of the Fisher assay value for the kerogen. The researchers concluded that chemically assisted recovery had promise, but that a key to its success was a dynamic flushing of the formation rather than a simple saturation of the formation with the chemical solution selected. No further research using similar solutions has been undertaken, however.

A.3.2 Processing Oil Shale

Processing oil shale involves two steps: (1) retorting to separate the organic and inorganic fractions and cause initial chemical transformations in the organic fraction (Section A.3.2), and (2) upgrading the resulting organic retorting products through additional chemical reactions until materials generally equivalent to conventional fuels are produced (Section A.3.2). Myriad physical, chemical, logistical, and environmental issues must be understood and managed for any given process to be technologically successful. Numerous technologies have been advanced for retorting and subsequently upgrading oil shale. However, the heterogeneous nature of oil shale virtually guarantees that no one retorting technology will be best in all circumstances, and further guarantees that a technology's performance at one location depends on a variety of site-specific factors. In addition to their impact on the yield and quality of final products, many technological issues also greatly influence economics. Availability of support resources such as electric power, heat, processing water, and reactants for use in upgrading reactions, as well as the nature of resulting environmental impacts and requirements for their control or mitigation, greatly impact the overall success, practicability, and cost of any given technology. Energy and environmental

efficiencies of oil shale processing technologies play as important a role as the richness and accessibility of the oil shale resource.

The following discussions provide brief descriptions of the technologies that have been identified for oil shale processing and focus on their overall effectiveness and anticipated environmental impacts. No endorsements are implied and no warranty is given that the discussions below represent a comprehensive array of technologies. Attempts were made to develop the evaluations below in terms of resource extraction, retorting, and upgrading. However, the technological approach to oil shale development is more sophisticated than those simplistic, separable steps would imply, as it occurs in a very integrated fashion. Although such integration of distinct steps would result in greater overall efficiencies, each technology is discussed separately in this appendix.

When the oil shale resource is extracted from its formation for ex situ processing, a certain number of preliminary preparatory steps may be required before retorting or upgrading can occur. These might involve separating the oil shale from other extraneous materials and free water and crushing it to the uniform particle size specified by the retorting process being used. Primary and secondary crushing can take place within a subsurface mine before the materials are brought to the surface. Uniform particle size of oil shale results in better retorting efficiencies and better overall efficiencies in materials management. When the raw resource has been retrieved from its formation as a liquid through in situ formation heating or other in situ recovery technologies, crushing and sizing are obviously not required; however, other actions such as separation of water (e.g., the small amount of formation water that entered the retort zone after heating commenced, as well as the water produced in kerogen pyrolysis and condensate that results when steam is used to heat the formation) and removal of entrained fine particulates are necessary prior to any retorting. All such crushing, sizing, and separating technologies are considered to be generic to resource mining and are not otherwise mentioned in the following discussions of particular retorting or upgrading technologies unless they have been shown to play especially critical roles in that technology's overall performance.

Organic fractions of oil shale are separated from the mineral fraction through a process known as retorting. During retorting, kerogen is released from the mineral surface to which it is adsorbed and subsequently undergoes chemical transformations in a process known as pyrolysis. When direct recovery methods are used (e.g., surface or subsurface mining), retorting the recovered oil shale causes thermal desorption of the organic fractions from the mineral fractions and the subsequent destructive distillation or pyrolysis of kerogen, which produces three product streams: crude shale oil (a collection of condensable organic liquids); flammable hydrocarbon gases; and char, a solid fraction of organic material that typically remains adsorbed to the mineral fraction of the shale. The char has limited value as an energy source for production of distillate fuels and is typically not further processed, although some retort designs call for it to be burned as a heat source for processing subsequent batches of mined oil shale. The liquid and gaseous products from retorting undergo additional processing to make them suitable for further refining off the mine site or for use on-site as fuel to sustain the mining and retorting operations. When recovery techniques are employed, only the kerogen or its pyrolysis products are recovered, and any subsequent aboveground retorting is conducted simply to complete kerogen pyrolysis. As will be discussed later, some MIS techniques have been specifically designed to

accomplish in situ pyrolysis of kerogen. The extent to which that pyrolysis occurs in situ will determine the need for further ex situ processing of recovered organic materials.

A.3.2.1 Aboveground Retorting Technologies

Initial attempts at oil shale pyrolysis were conducted in aboveground retorts (AGRs) by using designs and technical approaches that had been adapted from technologies developed for other types of mineral resource recoveries. There are numerous configurations for AGRs; these are differentiated by the manner in which they produce the heat energy needed for pyrolysis, how they deliver that heat energy to the oil shale, the manner and extent to which excess heat energy is captured and recycled, and the manner and extent to which initial products of kerogen pyrolysis are used to augment subsequent pyrolysis. Technologies include both direct and indirect heating of the oil shale. In direct heat retorting, some of the oil shale, char-bearing spent shale from previous retorting cycles, or some other fuel is combusted to provide heat for pyrolysis of the remaining oil shale, with the flame impinging directly on the oil shale undergoing retorting. Indirect heating, the more widely practiced alternative, involves the use of gases or solids that have been heated externally using a separate imported fuel or energy source and then introduced into the retort to exchange heat with the oil shale. Indirect heat sources include hot combustion gases or ashes from combustion of an external fuel, ceramic balls that have been heated by an indirect source, or even the latent heat contained in retort ash from previous retort cycles. The flammable hydrocarbon gases and hydrogen produced during retorting are also sometimes burned to support the heating process. While all retorts will produce crude shale oil liquids, hydrocarbon gases, and char, some have been designed to further treat these hydrocarbon fractions to produce syncrude. Other retorting processes contain auxiliary features to treat problematic by-products such as nitrogen- and sulfur-containing compounds; in some cases, they even convert these compounds to saleable by-products.

Comprehensive technical reviews of AGRs are contained in numerous reports published by or on behalf of various federal agencies, including DOE, the U.S. Environmental Protection Agency (EPA), and the U.S. Congress OTA (DOE 1982, 1983, 1988, 2004a,b; EPA 1977, 1979; NTIS 1979; OTA 1980a). Other technical reviews of AGRs also exist in the open literature (Heistand and Piper 1995).

Government-sponsored work in the development of AGRs specifically designed for oil shale was conducted in the 1960s under the direction of the U.S. Bureau of Mines. The gas combustion retort (GCR) was the design originally selected by U.S. Bureau of Mines for initial development of the Green River Formation oil shale at its demonstration mine at Anvil Points, Colorado. The GCR was a counterflow direct combustion retort. In addition to a relatively simple design and generally high production efficiencies, the most important advantage of GCRs is that they do not require cooling water, which makes them an excellent fit for the arid regions in which the majority of the Green River Formation oil shale exists. The U.S. Bureau of Mines-led project to develop the GCR involved a consortium of six commercial oil corporations: Mobil Oil, Humble Oil, Pan American, Sinclair, Phillips, and Continental Oil. The U.S. Bureau of Mines GCR designs were the models for many commercial direct combustion counterflow retorts, including the Paraho Direct Mode Retort. Development of the GCR was completed in

1967, before the promulgation of the National Environmental Policy Act (NEPA). Consequently, while some environmental impacts of the GCR were identified and measured, a comprehensive appreciation of its environmental impact was not established. However, environmental impacts from direct descendants of the GCR, such as the Paraho Direct Mode Retort, have been extensively defined and quantified.

AGRs have typically assumed the names of the RD&D projects in which they were developed, the corporation that conducted the RD&D, or their original inventors. At least eight separate retort designs have been developed to pilot stages, while only a few have reached commercial-scale applications. The following text, taken largely from the most recent DOE review (DOE 2004a) and from an EPA review (EPA 1979), provides information on a representative cross section of AGR technologies previously developed for application in the oil shale industry. The AGRs that collectively compose a representative sample of AGR technology include Union B, TOSCO II, Paraho (both direct and indirect modes), the Lurgi-Ruhrgas process, and Superior Oil's circular grate retort. Also included is a description of the Alberta Taciuk Process (ATP) technology, which was originally developed for processing tar sands but is currently being proposed for use in oil shale development.

A.3.2.1.1 Union B Retort. This retort was developed by the Union Oil Company of California (Unocal). It is an example of hot inert gas retorting. Crushed shale (0.32 to 5.08 cm [0.13 in. to 2.00 in.]) is fed through two chutes to a solids pump that moves shale upwards through the retort. The shale is heated to retorting temperatures by interaction with a counterflow of hot recycle gas [510 to 538°C (950 to 1,000°F)], resulting in the evolution of oil shale vapor and gas. Heat is supplied by combustion of the organic matter remaining on the retorted oil shale and is transferred to the (raw) oil shale by direct gas-to-solids exchange. The process does not require cooling water. This mixture is forced downward by the flow of recycle gas and cooled by contact with cold shale entering the retort in the lower section of the retort. Gas and condensed liquids are captured and separated at the bottom of the retort. Liquids are removed. Gases are sent to a preheater and returned to the retort for recovery of heat energy by burning. The captured liquids are further treated for removal of water, solids, and arsenic salts. Once the system reaches equilibrium, no external fuel is required; heat is supplied by the combustion of hydrocarbon gases produced during retorting. Pollution control devices are integrated into the design for removal of hydrogen sulfide (H₂S) gas and NH₃ gas produced during retorting and for treatment of process waters recovered from oil/water separations. Treated waters are recycled, used for cooling the spent shale, or delivered to mining and handling operations and used to moisten the shale for fugitive dust controls.

The Union B Retort design offers particular advantages. The reducing atmosphere maintained in the retort results in the removal of sulfur and nitrogen compounds through the formation of H₂S and NH₃ gas, respectively, both of which are subsequently captured. Forcing the hot, newly formed oil vapors to immediately contact the cooler shale entering the retort results in their rapid quenching. This is thought to minimize polymer formation among the hydrocarbon fractions, improving not only the overall yield of crude shale oil but also its quality. Additional treatment of the initially formed shale oil and the removal of heavy metals, such as

arsenic, results in a final product recovered from the retort that can be used directly as a low-sulfur fuel or delivered to conventional refineries for additional refining.

A.3.2.1.2 TOSCO II Retort. The TOSCO II Retort, developed by The Oil Shale Corporation, is more correctly described as a retorting/upgrading process. Its design is unique in two respects: it is one of only a few retorts that have operated in the United States that employ a solid-to-solid heat exchange process, and it is the only process that fully integrates oil shale retorting and shale oil upgrading steps to produce an upgraded syncrude, as well as liquefied petroleum gas (LPG) and saleable sulfur, NH_3 , and coke by-products. Although they are independent of each other, the retort and the various upgrading units are designed to work together.

Crushed and sized (nominally to 1/2 in.) raw oil shale is preheated to 500°F by interaction with flue gases from a ceramic ball heater. The preheated shale is introduced into a horizontal rotary kiln together with 1.5 times its weight in previously heated ceramic balls. The temperature of the shale is raised to its minimal retort temperature of 900°F. The kerogen is converted to shale oil vapors that are withdrawn and fed to a fractionator for hydrocarbon recovery and water separation. Spent shale and the ceramic balls are discharged and separated; the ceramic balls are returned to their heater; and the spent shale is cooled, moistened for dust control, and removed for land disposal. The fractionator separates the shale oil hydrocarbon vapors into gas, naphtha,⁹ gas oil, and bottom oil. The gas, naphtha, and gas oil are sent to various upgrading units, while the bottom oil is sent to a delayed coking unit, where it is converted to lighter fractions and by-product coke. Gas oil and raw naphtha are both upgraded in separate hydrogenation units through reaction with hydrogen at high pressure. The hydrogen is actually produced on-site from steam reforming of the fuel gas originally recovered from the retort. In addition to improving the H/C ratio of the hydrocarbons, the hydrogenation units also convert any sulfur present to H_2S and any nitrogen present to NH_3 . The NH_3 is captured for sale, while the H_2S is sent for further treatment, where it is converted to saleable sulfur. Other saleable products from the hydrogenation units include LPG and butane.

A.3.2.1.3 Paraho Retorts. The Paraho retorts, developed by Development Engineering, Inc., have been in service in oil shale fields in both Colorado and Brazil. Two versions exist, direct mode and indirect mode, both utilizing vertical retorting chambers. In the direct mode retort, some of the raw shale is ignited in the combustion zone of the retort to produce the heat that pyrolyzes the remaining oil shale present in higher zones. The Paraho direct mode retort is an example of the U.S. Bureau of Mines GCR. In the indirect mode retort, heat is generated in a separate combustion chamber and delivered to lowermost portion of the retorting chamber.

In the direct mode Paraho retort, crushed and sized oil shale is fed into the top of the vertical retorting vessel. At the same time, spent shale (previously retorted oil shale that contains

⁹ "Naphtha" is a general term applied to refined or unrefined petroleum products, not less than 10% of which distill below 347°F (175°C) and not less than 95% of which distill below 464°F (240°C) when subjected to standardized distillation methods (Sax and Lewis 1987).

solid carbonaceous char) is ignited in a lower level of the retort. Hot combustion gases rise through the descending raw shale to pyrolyze the kerogen. Oil vapors and mists formed in the uppermost portion of the retort are removed. The liquid fraction is captured for further upgrading in independent facilities. The gaseous fraction is cleaned for sale, while a small portion is returned to the retort and combusted together with the spent shale.

In the indirect mode Paraho retort, the portion of the vertical retorting chamber that was used for oil shale combustion in the direct mode is now the region of the retort chamber into which externally heated fuel gas is introduced. No combustion occurs within the retorting chamber. That separate combustion process is typically fueled by commercial fuels (natural gas, diesel, propane, etc.) that are often augmented with a portion of the fuel gas recovered from the retorting operation. While they are very similar in operation, the direct and indirect mode Paraho retorts offer sufficiently different operating conditions so as to change the composition of the recovered crude shale oils and gases. Oil vapors and mists leave the direct mode retort at approximately 140°F, while the vapors and gases in the indirect mode leave the retorting vessel at 280°F and have as much as nine times higher heating values than gases and vapors recovered from the direct mode retort (102 Btu/scf vs. 885 Btu/scf, or 908 kcal/m³ vs. 7,560 kcal/m³) (EPA 1979). This is thought to be due principally to the fact that oil vapors and mists recovered from the direct mode are “diluted” with combustion gases from the combustion of the spent shale at the bottom portion of the retort. Characteristics of the recovered raw shale oil are somewhat different for the direct and indirect mode retorts, but each has characteristics similar to shale oils recovered from other retorts using similar shale heating mechanisms (direct vs. indirect). Retort gases also differ from the two modes. Gases from indirect mode retorts have much lower levels of CO₂ (due to the lack of dilution by gases from direct combustion) but generally higher levels of H₂S, NH₃, and hydrogen, which are thought to be the result of the indirect mode retort having much less of an oxidizing environment than the direct mode retort (EPA 1979). Finally, the Paraho retort can also be operated in a direct/indirect hybrid mode.

A.3.2.1.4 Lurgi-Ruhrgas Process. The Lurgi-Ruhrgas technology was developed in Germany for the production of pipeline-quality gas through the devolatilization of coal fines. The technology has operated at commercial scales for the devolatilization of lignite fines, the production of char fines for briquettes from sub-bituminous coal, and the cracking of naphtha and crude oil to produce olefins. As with the Paraho process, the Lurgi-Ruhrgas process was designed from its inception not only to retort kerogen but also to refine the resulting hydrocarbons into saleable liquid and gaseous petroleum fractions.

In this process, crushed and sized (–0.25 in.) oil shale is fed through a feed hopper and mixed with as much as six to eight times its volume of a mixture of hot spent shale and sand with a nominal temperature of 1,166°F and conveyed up a lift pipe. This mixing raises the average temperature of the raw shale to 986°F, a temperature sufficient to cause the evolution of gas, shale oil vapor, and water vapor. The solids mixture is then delivered to a surge hopper to await additional processing in which more residual oil components will be distilled off. The sand, introduced as a heat carrier, is recovered and recycled. The mixture is then returned to the bottom of the lift pipe and allowed to interact with hot combustion air at 752°F. The carbonaceous fraction is burned as the mixture is raised pneumatically up the lift pipe and transferred to a

collection bin where the spent shale fines are separated from gases. The hydrocarbon gases and oil vapors are processed through a series of scrubbers and coolers to eventually be recovered as condensable liquids and gases. Because the shale particle size is initially so small, management of fines is critical throughout the process and involves the use of sedimentation and centrifuging as well as numerous cyclones and electrostatic precipitators.

A.3.2.1.5 Superior Oil's Circular Grate Retorting Process. One retort design advanced by Superior Oil theoretically offers substantial environmental advantages over other retorting processes. The design is a counterflow, gas-to-solid heat exchange process conducted in an enclosed circular grate. Shale in a relatively wide range of sizes (0.25 to 4.0 in.) is added, rotated to the first segment of the retort, and heated by a continuously circulating gas medium. Volatilized oil (mists) mixes with the circulating gas and, together with water, is periodically removed from the gas stream. The partially pyrolyzed shale rotates to the next segment of the retort where it is partially oxidized to complete the kerogen pyrolysis and oil evolution. The spent shale cools in the next segment of the grate as it yields heat to the circulating gas. Additional heat is added to the first segment of the grate where initial pyrolysis of raw shale takes place either through direct or indirect combustion of gases recovered from previous shale retorting. This design has been used for many years in the processing of various ores, including iron ores, and consequently has a relatively high reliability factor.

Only pilot-scale experiences exist for this retort when applied to oil shale. However, numerous tests have identified critical control parameters and optimized operations resulting in oil recovery yields greater than 98% Fisher assay results. From an environmental perspective, the circular grate holds great promise, since it is essentially a sealed operation with hooded enclosures above the grate, to capture hydrocarbon gases and oil mists, and water seals (water troughs) below the grate, where spent shale is discharged. The water seals prevent gas and mist leakage and also provide for the moistening of the spent shale that is necessary for its safe handling and disposal.

Another unique aspect to the Superior circular grate retort is that it was designed to be operated in conjunction with subsystems for the recovery of alumina and soda ash. Thus, this design appears well suited for applications where saline deposits coexist with oil shale or are present above or below the shale. In the Superior Oil circular grate process, spent shale is delivered to subsystems that convert the saline minerals to saleable products. For example, commonly encountered dawsonite [$\text{NaAl}(\text{OH})_2\text{CO}_3$] can be converted to alumina (aluminum oxide [Al_2O_3] and soda ash [NaCO_3]). Further, conditions during kerogen retorting are favorable for the simultaneous conversion of nahcolite (NaHCO_3) to soda ash, CO_2 , and water.

Technical advantages to this retort include the circumstance that the circulating shale is independent of the circulated gas above it and that considerable experience with this type of retort has identified and resolved the major operational problems. Although designed to operate continuously, the unit can be quickly shut down and restarted. Temperature control is excellent, resulting in high hydrocarbon recovery rates and relatively minor amounts of sintering of the inorganic phase of the shale (Nowacki 1981).

A.3.2.1.6 Alberta Taciuk Process. The ATP is an AGR technology originally researched and designed for the extraction of bitumen from tar sands in Canadian tar sands deposits, some of the largest and richest deposits of their kind in the world. The ATP was developed by UMATAC Industrial Processes, a division of UMA Engineering, Ltd., which supplies the technology under license agreements.

The ATP Processor is the primary processing component of the technology and it works in conjunction with a number of ancillary subsystems that, together, make up the ATP System. As with many of the retorting technologies discussed above, the ATP System provides more than simple retorting; the Processor, together with its subsystems, can provide primary upgrading of the initial retort products, as well as capture and control of problematic by-products.¹⁰ The ATP is a dry thermal process involving indirect heating of oil shale using countercurrent gas-solid heat exchange as well as the generation of process heat by combustion of coke (carbon present on retorted oil shale solids) in the combustion zone of the kiln. The ATP has been successfully applied to retorting oil shale and has achieved improved yields of raw shale oil and combustible gases over other retorting technologies developed and used specifically for the oil shale industry. The ATP provides high heat-transfer efficiencies and integral combustion of coke for process heat demands, which minimizes the amount of residual coke remaining on spent shale. This combination minimizes CO₂ release per ton of shale processed and reduces the potential for environmental contamination from improper spent shale disposal (DOE 2004a).

A schematic flow diagram of the ATP System is shown in Figure A-3. A pictorial representation of the functioning of the ATP Processor is shown in Figure A-4.

The ATP System also represents the likely direction of future AGR equipment in that it is fitted with environmental control equipment to lessen the impact of air emissions and water effluents typically resulting from retorting. The ATP technology has successfully operated at semicommercial demonstration scale in Australia and is to be used commercially in China. There is evidence to suggest that the ATP System will also continue to be applied to future oil shale development.¹¹

A.3.2.2 In Situ Retorting

First attempts at in situ formation heating were pursued with the intention of mobilizing the kerogen to facilitate its movement through the formation for extraction by conventional pumping/extraction devices. However, the objectives of in situ formation heating investigations quickly expanded to include in situ pyrolysis of the kerogen.¹² Both TIS and MIS recovery techniques have been explored for their compatibility with in situ retorting. While most past

¹⁰ Many other AGRs could also be fitted with air pollution control equipment.

¹¹ The Oil Shale Exploration Company (OSEC) is one of the applicants whose project is under consideration as part of the BLM's oil shale RD&D program. OSEC proposes to use a modified version of the ATP system for oil shale development in the Uinta Basin in Utah. Additional details of the OSEC RD&D initiative, as well as the other five RD&D initiatives, are provided in Section A.4.

¹² In situ retorting is said to have been attempted in Estonia in the 1940s (EPA 1979).

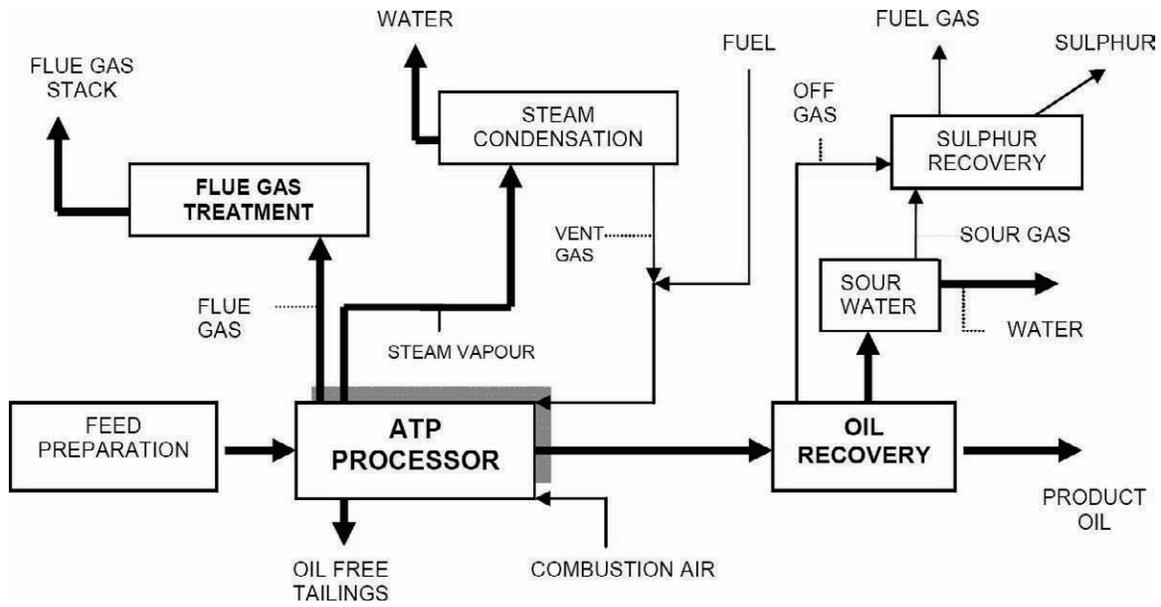


FIGURE A-3 ATP System Flow Diagram Processor (Source: UMATAC Industrial Processes; reprinted with permission)

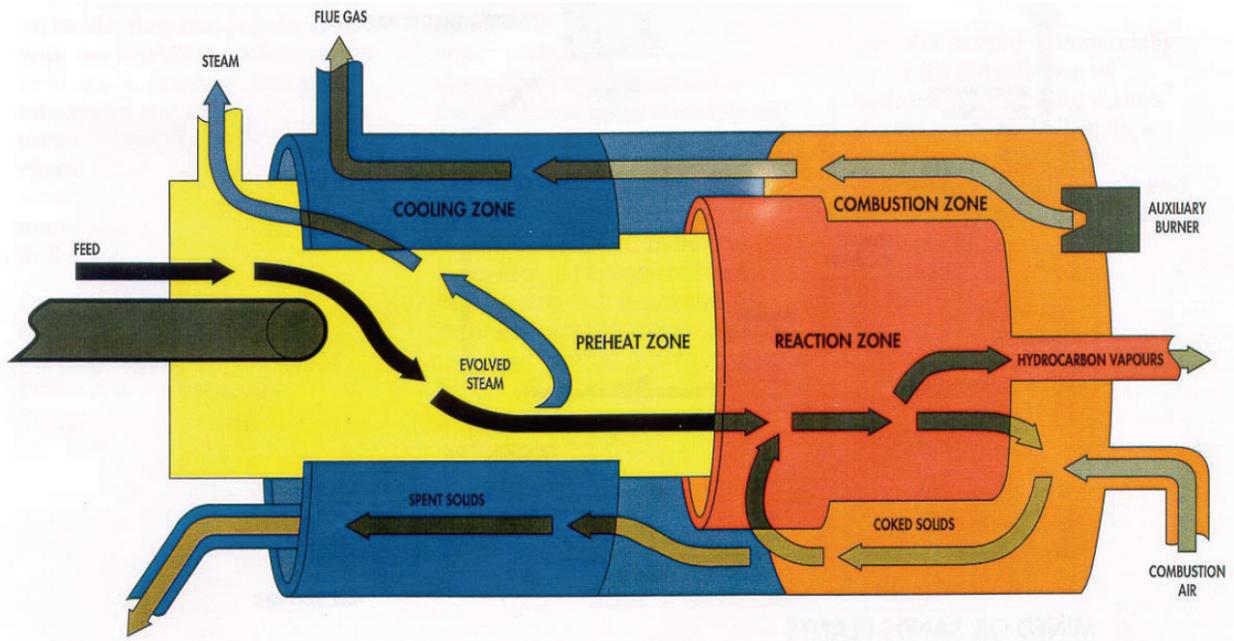


FIGURE A-4 Pictorial Representation of ATP Processor (Source: UMATAC Industrial Processes; reprinted with permission)

research has utilized MIS techniques, recently proposed research has begun to pursue techniques that can more properly be described as TIS.

Myriad in situ retorting designs have been proposed. As a result of his literature review, Lee (1991) has suggested three fundamental design dimensions on which to categorize in situ retorting technologies: (1) the mechanism by which heat is introduced into or produced within the formation, (2) the manner and extent to which the technology modifies natural fracturing patterns in the formation to ensure adequate permeability, and (3) whether the technology employs a TIS or MIS approach to recovery of organics. Lee further notes that most in situ technologies that have undergone field testing qualify as MIS and involve altering the formation by enhancing fracturing and/or by creating voids that would serve as retort chambers. Differences in approaches among MIS technologies center on the manner in which formation voids are formed, the shape and orientation of such voids (horizontal vs. vertical), and the actual retorting and product recovery techniques employed. Retorting techniques can include controlled combustion of rubble shale, or formation heating by alternative means such as the introduction of electromagnetic energy. Product recovery techniques have included steam leaching, chemically assisted or solvent leaching, and displacement by high-pressure gas or water injection. Some of these formation sweeping techniques also can be seen as aiding or promoting additional refining of the initial retorting products. It is beyond the scope of this summary to discuss in detail all or even a majority of the designs that have been developed; Lee (1991) has provided a comprehensive listing of the patents that have been issued for these designs.

Hydrocarbon products of successful in situ heating are similar in character to the products recovered from AGRs: petroleum gases, hydrocarbon liquids, and char. Field experiences with the first generation in situ retorts indicate that the petroleum gases tend to be of lesser quality than gases recovered by AGRs.¹³ The condensable liquid fraction, however, generally tends to be of better quality than the liquid hydrocarbon fractions recovered from AGRs with higher degrees of cracking of the kerogen macromolecules and elimination of substantial portions of the higher boiling fractions typically produced in AGRs. Overall yields with any in situ retorting tend to be lower than yields from equal amounts of oil shale of equivalent richness processed through AGR (EPRI 1981). Various explanations have been advanced for these observed differences. Some of the loss of quality for recovered gases may be the dilution that results when heat is introduced to the formation by injection of combustion gases and/or steam, by advancement of a flame front as a result of combustion of some portion of the shale, or when high-pressure gases are used to sweep retorting products from the formation to recovery wells. The quality improvements for the liquid fraction may be due to the relatively slow and more even heating that can be attained in a properly designed and executed in situ retorting process. Such quality improvements also may be indicative of further refining of initial retorting products when sweep gases such as natural gas or hydrogen are used. Finally, and importantly from an environmental perspective, the char and the mineral fraction to which it is adsorbed are not recovered but remain in the formation, significantly reducing (but not completely eliminating)

¹³ However, gases recovered from in situ retorting that does not involve combustion are expected to be equivalent in quality to gases recovered from AGRs.

collateral environmental impacts from solid by-product wastes. Limited evidence collected by the EPA suggests that groundwater quality impacts may still result from in situ spent shale.

Experience with AGRs clearly demonstrated that the conditions maintained during pyrolysis significantly influence the composition, quality, and yield of recovered products, including unwanted by-products, much more so than does the initial composition of the oil shale. Establishing and maintaining such strict controls in situ is a significant engineering challenge. Overcoming this challenge requires significant effort, but the ultimate return is equally significant. There are unique and substantial operational and environmental advantages to in situ recovery, and even more and greater advantages result from successful in situ retorting, including the following:

- Simplified material handling requirements (only the retorted organic fraction, roughly less than 15% by weight of the parent oil shale, would need to be recovered from the formation);
- Greater portions of the deposit would be accessible for economical kerogen recovery (albeit perhaps at a lower overall recovery efficiency);
- Spent shale from conventional retorting, a significant solid waste issue, would be virtually eliminated;
- Overall energy efficiencies may increase over conventional retrieval and AGR methods;
- Air pollution potential would be significantly reduced;
- Noise pollution would be severely reduced;
- Impacts on ecosystems and fugitive dust potential would be reduced because of the smaller aerial extent of surface industrial activities and the reduced land area required for material stockpiles and solid waste disposal; and
- Surface water quality impacts would be reduced because of the reduced size of land disposal areas and the reduced potential for stormwater pollution from interim material and waste pile runoff.

In situ retorting also has some potential disadvantages. Intuitively, the overall success of any in situ retorting technology results from its ability to distribute heat evenly throughout the formation. Indiscriminate formation heating that allows portions of the formation to reach 1,100°F can result in technological problems, as well as the thermal decomposition of mineral carbonates and the formation and release of CO₂. From an operational standpoint, such decompositions are endothermic and will result in the energy demands of such uncontrolled in situ retorting quickly becoming insurmountable. As noted above, environmental consequences of carbonate decomposition during in situ retorting can be expected to be mitigated to a large extent by the natural CO₂ sequestrations that can also be anticipated. Nevertheless, the lack of precise

heat control will devastate both the yields and the quality of recovered hydrocarbons and must be avoided. However, in situ retorting with good thermodynamic controls can produce pyrolysis products of equal or even greater quality than AGR.

Another potential disadvantage to in situ retorting involves the time that it takes to heat substantial masses of formation materials to retorting temperature (on the order of months or years) and the energy costs over that period. Field experiences are limited, and, because every formation accepts heat differently, it is difficult to define a universal time line or perform precise, reliable energy balances except on a site-specific basis.

Other largely unanswered questions involve long-term impacts from retorted segments of oil shale formations. Questions regarding long-term impacts include:

- Will vacated pore spaces need to be filled to prevent surface subsidence?
- Will groundwater flow patterns change significantly?
- Will groundwater interactions with retorted shale minerals facilitate the leaching of heavy metals or other contaminants?
- Will water produced from in situ combustion become a conduit for delivery of contaminants to existing groundwater aquifers?
- Will CO₂ produced in situ be safely sequestered indefinitely within the formation?

While conceptual designs for in situ retorting are numerous, only limited field activities have been pursued, mostly undertaken as proof-of-concept exercises, but, in a few instances, with the intent of advancing the practical development and application of specific in situ retort designs. Field data on both the short- and long-term impacts of in situ retorting are therefore limited. Independent investigations were conducted as early as 1953. Government-sponsored research began in the 1960s. The following sections provide brief descriptions of the early research and a more extensive description of only the most prominent in situ retorting technology. Also included are brief descriptions of RD&D projects that have been recently proposed and approved by the BLM for further research and that also involve some form of in situ retorting.

A.3.2.2.1 Early In Situ Retorting Experiments. Lee (1991) has provided the following brief summaries of some of the earliest research into in situ technologies:

- ***Sinclair Oil and Gas.*** Sinclair's experiments investigated one of the earliest uses of high-pressure air injected into the formation to sweep retort products to recovery wells.

- **Equity Oil Company.** Equity's process used hot natural gas to both retort the shale and sweep the retort products to recovery wells.
- **Laramie Energy Technology Center (LETC).** LETC sponsored some early research into in situ retorting in the early 1960s at Rock Springs, Wyoming. The purposes of this research were twofold: (1) establish the best mechanisms for enhancing the fracturing of the formation to increase its permeability, and (2) investigate the process by which in situ combustion of shale and the subsequent movement of a heat front through the formation could be made self-sustaining.
- **Dow Chemical.** Dow Chemical's research was conducted on eastern United States shale in Michigan, but much of the experience is transferable to western shales. Dow's experiment was one of the earliest examples of TIS. It used explosives to enhance fracturing and electrical resistance heaters combined with propane-fired burners to effect in situ retorting.
- **Geokinetics, Inc.** The Geokinetics process was one of the earliest uses of horizontally oriented retort voids in an MIS process. This DOE-sponsored research occurred near Grand Junction, Colorado, in the Parachute Member of the Green River Formation and also in the Mahogany Zone. Importantly, this research proved the value of horizontal retort chambers in relatively thin shale deposits.

A.3.2.2.2 The Occidental Oil Shale MIS Retort Technology. OOSI conducted much of the pioneering investigations into in situ retorting under the auspices of a DOE contract, issuing its final report in January 1984. Although the operation was under the control of OOSI, personnel from DOE's Sandia National Laboratories provided consultation services throughout the project and were instrumental in development of the final report (Stevens et al. 1984). The project was conducted in two phases near Logan's Wash near Debeque, Colorado, and represents one of the most extensive research ventures into MIS vertical in situ retorting technology.

The OOSI experiment was conducted in two phases and was intended to provide demonstrations of mining, rubblizing, ignition, and simultaneous processing of commercial-sized MIS retorts. Although the primary thrust of the research involved the development of design and operating parameters for the MIS in situ retort, support systems, including surface processing of retort products, were also investigated.

The retorting technology involved creating a void in the oil shale formation using conventional underground mining techniques.¹⁴ Explosives (ammonium nitrate and fuel oil [ANFO]) were then introduced to cause the "rubblizing" of some of the shale on the walls of the

¹⁴ In commercial application, numerous voids would be created, spaced throughout the formation and collectively representing a removal of 15 to 20% of the formation volume of shale that would be brought to the surface for conventional AGR.

void and to expand existing fractures in the formation, improving its permeability.¹⁵ Access to the void was sealed and a controlled mixture of air and fuel gas (or alternatively, commercial fuel such as propane or natural gas) was introduced to initiate controlled ignition of the rubblized shale. Combustion using this external fuel continued until the rubblized shale itself was ignited, after which external fuel additions were discontinued and combustion air continued to be provided to the void to sustain and control combustion of the shale.¹⁶ The resulting heat expanded downward into the surrounding formation, heating and retorting the kerogen. Retort products collected at the bottom of the retort void and were then recovered from conventional oil and gas wells installed adjacent to the void. Careful control of combustion air/fuel mixtures was the primary control over the rate of combustion occurring in the heavily instrumented and monitored void. Once recovery of retorted oil shale products equilibrated, a portion of the hydrocarbon gases was recycled back into the void to be used as fuel to sustain in situ combustion.¹⁷ Two separate retorts were constructed and operated during Phase II of the project, with the last two retorts shutting down in February 1983.

Ultimately, oil recovery was equivalent to 70% of the yield predicted through Fisher assay. Design of the experiment was directed toward potential future commercial applications so numerous that such in situ retorts were operated simultaneously to demonstrate the practicability of an approach that would likely have been desirable in commercial development ventures. Conceptual views of the OOSI in situ retort and the expected movement of the heat front through the formation are displayed in Figures A-5 and A-6, respectively.

From a technological perspective, the OOSI in situ retorting experiment was a success. Recovered crude shale oil has a specific gravity of 0.904 (American Petroleum Institute [API] gravity of 25°¹⁸), a pour point of 70°F, a sulfur content of 0.71% (by weight), and a nitrogen content of 1.50% (by weight). OOSI believes that crude shale oil meeting those specifications would be available for use as a boiler fuel without further processing or would certainly constitute acceptable refinery feedstock for additional refining to other conventional fuels.

From an environmental perspective, many questions were raised regarding the type and scale of environmental impacts that would result from either the initial in situ retorting or from the subsequent use of the resulting shale oil in industrial boilers or furnaces, and some of those

¹⁵ Although the original research utilized explosives, it can be anticipated that for some shale formations, sufficient alterations can be accomplished with the injection of high-pressure water (hydrofracturing).

¹⁶ Phase II experimented with the use of hot inert gas to preheat the rubblized shale, followed by air to initiate combustion.

¹⁷ Hydrocarbon gases recovered from this process are of only moderate quality, having been diluted by gases of combustion as well as CO₂ from carbonate decomposition. Typically, the recovered gases had a heating value of less than 65 Btu/scf. In the OOSI design, the fraction of the gas that was not introduced back into the formation to support further combustion was used on-site for power and/or steam generation.

¹⁸ The pour point is the temperature at which the petroleum liquid's viscosity is sufficiently low to allow pumping and transfer operations with conventional liquid handling equipment. American Petroleum Institute (API) gravity is an arbitrary scale for expressing the specific gravity or density of liquid petroleum products. Devised by the API and the National Bureau of Standards, API gravity is expressed as degrees API. API gravities are the inverse of specific gravity. Thus, heavier viscous petroleum liquids have the lower API values.

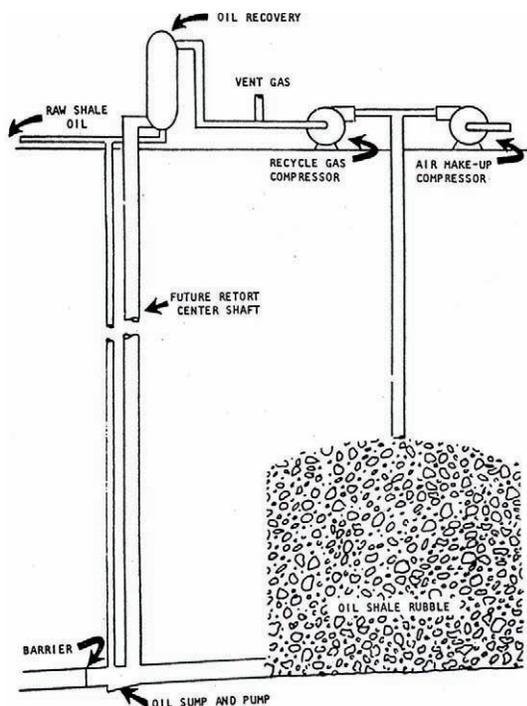


FIGURE A-5 Conceptual Design of the Occidental Oil Shale, Inc., MIS Retorting Process (Source: EPA 1979)

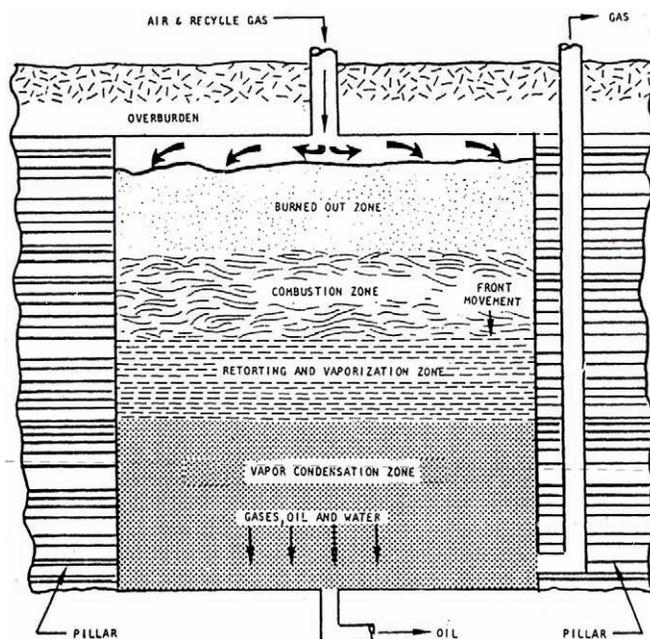


FIGURE A-6 Conceptual View of the Downward Movement of the Heat Front through the Formation in the Occidental Oil Shale, Inc., Vertical In Situ Retort (Source: EPA 1979)

questions remain unanswered. As part of its development plan, OOSI identified as many as 48 separate activities associated with this technology for which there could be an environmental impact. Environmental monitoring throughout the project and beyond was scheduled to verify and quantify those impacts. However, the magnitudes of many of OOSI's anticipated impacts are disputed by the EPA.

First, the EPA disputes the OOSI claim of the magnitude of nitrogen oxides (NO_x) emissions that would result from combustion of the recovered crude shale oil in an industrial boiler, believing that the amount would be much greater than that claimed. Second, it has not been reliably demonstrated that all of the CO_2 generated during the retorting (from combustion sources as well as carbonate decomposition) would be successfully sequestered in the formation indefinitely. Thirdly, major water management problems exist. It was estimated that the volume of retort water created during retorting plus the amount of water used for surface processing (upgrading) of retort products and for fugitive dust control throughout the operational area is essentially equivalent to the volume of crude shale oil produced. Thus, a substantial volume of water may require treatment before discharge or recycling. Further, groundwater monitoring data appear to indicate that groundwater contamination had occurred, both during and after completion of retorting. The extent to which the retort water contains contaminants that would require proper treatment could not be reliably predicted, and it is not clear whether any or all of this water could be recycled for use in future processing.

Conclusions from a thorough analysis of water quality impacts from MIS retorts were summarized in the OOSI final report:

- Total alkalinity, NH₃, phenols, dissolved organic carbon, thiosulfate, and thiocyanide concentrations are significantly higher in retort water (i.e., waters recovered from retorts during operation) than in natural water;
- Aluminum, magnesium, and calcium concentrations are lower in retort water than in natural water;
- Monitoring data from wells near the retort operations showed no discernable trends that could be interpreted as contamination from the retorts; however,
- Trends over time indicate that concentrations of constituents thought to be leaching from the retired retorted areas initially increase significantly from natural waters but also quickly equilibrated (in a matter of 2 years or less) to levels approximating the concentrations in natural waters without any intervention or remediation, suggesting that most leaching occurs from the initial flushing of retorted zones by infiltrating groundwater, but also that the amounts of leachable materials remaining in retorted zones appear to be limited.

A.3.3 Upgrading Oil Shale

Irrespective of the resource recovery and retorting technologies employed, kerogen pyrolysis products are likely to require further processing or upgrading before becoming attractive to oil refineries as feedstocks for conventional fuels. Upgrading crude shale oil to produce syncrude for delivery to refineries is analogous to the early steps of crude oil refining. The refining process is complex but nevertheless well understood and well documented. The discussions that follow provide only a cursory review of those aspects of refining that are most relevant to mine site upgrading of crude shale oil.

Refining crude oil involves a great variety of reactions. Preliminary steps are taken to separate extraneous materials that may be present in the crude oil feedstock (e.g., water, suspended solids). Crude oil fractions are separated (fractionated) by their boiling points in atmospheric and/or vacuum distillations. Distillation fractions are subjected to heat, causing the thermal decomposition of large molecules into smaller ones (coking or cracking). Thermal cracking products are then subjected to a variety of chemical reactions designed to modify their chemical compositions either by removing hydrogen and other atoms to form compounds composed largely of carbon (e.g., delayed coking, fluid coking) or by adding hydrogen while removing hetero atoms, such as sulfur and nitrogen, to form organic compounds composed exclusively of carbon and hydrogen (catalytic or thermal hydrocracking, hydrotreating, desulfurization, and hydrogenation). Finally, various treatment reactions are conducted to remove contaminants or modify chemicals that would be the source of air pollution when the petroleum product is later consumed by combustion. Numerous other specialized reactions are

interspersed within this scheme, which is designed to reformulate organic molecules into chemicals that change the physical or chemical properties of the commercial fuel mixtures in which they are contained.

Upgrading crude shale oil at the mine site might consist of all of the above steps, although hydrogen-addition reactions generally predominate, and reactions to produce specialty chemicals are not likely to occur at all. Upgrading is typically directed only at the gaseous and liquid fractions of the retorting products and is rarely applied to the solid char that remains with the inorganic fraction of the oil shale, although coking of that solid fraction is possible. The most likely end products will be refinery feedstocks suitable for the production of middle distillates (kerosene, diesel fuel, jet fuel, No. 2 fuel oil), although lighter weight fuel components such as gasolines can also be produced. In general, hydrotreating followed by hydrocracking will produce jet fuel feedstocks, hydrotreating followed by fluid catalytic cracking is performed for production of gasoline feedstocks, and coking followed by hydrotreating is performed with the intention of producing diesel fuel feedstocks (Speight 1997).

Similar to the preliminary steps taken at refineries, prior to or coincident with crude shale oil upgrading reactions, there are also activities to separate water from both the gas and liquid fractions, to separate oily mists from the gaseous fraction, and to separate and further treat gases evolved during retorting to remove impurities and entrained solids and improve their combustion quality.¹⁹ Actions to remove heavy metals and inorganic impurities from crude shale oils also take place.

Upgrading activities are dictated by factors such as the initial composition of the oil shale, the compositions of retorting products,²⁰ the composition and quality of desired petroleum feedstocks or petroleum end products of market quality, and the business decision to develop other by-products such as sulfur and NH₃ into saleable products.²¹ Product variety and quality issues aside, there are other logistical factors that determine the extent to which upgrading activities are conducted at the mine site. Most prominent among these factors is the ready availability of electric power and process water. In especially remote locations, factors such as these represent the most significant parameters for mine site upgrading decisions.

The initial composition of the crude shale oil produced in the retorting step is the primary influence in the design of the subsequent upgrading operation. In particular, nitrogen

¹⁹ Removal of entrained solids is typically accomplished by simple gravity or centrifugal separation techniques such as cyclone separators. However, other techniques have been developed, including high-gradient magnetic separation (Lewis 1982).

²⁰ The composition of retort products is dictated by conditions during retorting. In general, pyrolysis of kerogen at the lowest temperature possible yields the highest proportion of saturates over olefinic and aromatic constituents. Higher retorting temperatures yield increasingly greater amounts of aromatic compounds until, at the retorting temperature of 871°C, Colorado Green River Formation shale can be expected to yield 100% aromatic compounds (Speight 1990).

²¹ Elemental sulfur has widespread use in a wide variety of industry sectors: pulp and paper, rubber, pharmaceutical, detergents, insecticides, and explosives. Likewise, NH₃ enjoys widespread industrial applications, such as agricultural fertilizers, textiles, steel treatment, explosives, synthetic fibers, and refrigerants.

compounds, sulfur compounds, and organometallic compounds dictate the upgrading process that is selected. In general, crude shale oil typically contains nitrogen compounds (throughout the total boiling range of shale oil) in concentrations that are 10 to 20 times the amounts found in typical crude oils (Griest et al. 1980). Removal of the nitrogen-bearing compounds is an essential requirement of the upgrading effort, since nitrogen is poisonous to most catalysts used in subsequent refining steps and creates unacceptable amounts of NO_x pollutants when nitrogen-containing fuels are burned.

Sulfur, also a poison to refinery catalysts, is typically present in much lower proportions as organic sulfides and sulfates. With respect to sulfur, crude shale oil compares favorably with most low-sulfur crude oils, which are preferred feedstocks for low-sulfur fuels that are often required by local air pollution regulations. Hydrotreating to the extent necessary to convert nitrogen compounds to NH₃ is sufficient in most instances to simultaneously convert sulfur to H₂S. Crude shale oil additionally contains much higher amounts of organometallic compounds than conventional crude oils. The presence of these organometallic compounds complicates the mine site upgrading, since they can readily foul the catalysts used in hydrotreating, causing interruptions in production and increased volumes of solid wastes requiring disposal, sometimes even requiring specialized disposal as hazardous wastes because of the presence of spoiled heavy-metal catalysts.

Desired end products for mine site upgrading are typically limited to mixtures of organic compounds that are acceptable for use as conventional refinery feedstock; however, it is possible to produce feedstocks that are of higher quality and value to refineries than even crude oils having the most desirable properties. Since crude shale oils are typically more viscous than conventional crude oils, their yields of lighter distillate fractions such as gasolines, kerosene, jet fuel, and diesel fuel are typically low. However, additional hydrotreating can markedly increase the typical yields of these distillate fractions.

Given the high capital costs involved in constructing and operating more sophisticated refining operations at remote mine sites, there is little incentive for mine operators to duplicate existing refinery capabilities, and most oil shale development business models will likely include only the upgrading that is minimally necessary for the end products to be acceptable to conventional refineries and capable of being transported to those refineries by existing conveyance technologies (i.e., sufficiently improved API gravities and pour points). Such a business model was endorsed by the Committee on Production Technologies for Liquid Transportation Fuels of the National Research Council in 1990 and is believed to still be applicable today (National Research Council 1990).

All of the factors controlling upgrading are very site- and project-specific. At the PEIS level, it is not possible to precisely describe all of the actions that may be undertaken for the purposes of upgrading retorting products; however, a general overview of the nature of those reactions is provided below. An example of an explicitly defined upgrading scheme is provided in the BLM's *Final Environmental Impact Statement for the Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, Volume I* (BLM 1977).

Upgrading is designed to increase the relative proportion of saturated hydrocarbons over unsaturated hydrocarbons in the crude shale oil recovered from retorting and to eliminate the other compounds present that can interfere with further refining of the crude shale oil into conventional middle distillate fuels (primarily, compounds containing nitrogen or sulfur atoms). Hydrogen at high temperatures and pressures is used to create a reducing atmosphere in which olefinic or aromatic hydrocarbons are converted to alkanes (or saturates), and organic compounds containing sulfur or nitrogen are destroyed with the sulfur and nitrogen being converted to H₂S and NH₃, respectively, which are then captured and removed. As upgrading converts crude shale oil to syncrude, the physical properties change significantly. As a practical matter, the pour point and API gravity of the liquid fraction are substantially increased, making syncrude much easier to handle and transport than crude shale oil (typically another stated goal of mine site upgrading). Gaseous components are converted to fuel gas, LPG, and butanes,²² all becoming available for use as fuels to support further oil shale processing or as marketable materials for sale at the wholesale or retail level. Most probably, gases such as propane and propylene would be stored and receive an appropriate odorant gas (e.g., methyl mercaptan) for eventual sale as LPG, while any hydrogen produced as well as the butane/butylene fraction are more likely to be returned to the retorting process and consumed as supplemental fuel.

A.4 SPENT SHALE MANAGEMENT

An important component of surface mining and underground mining projects is spent shale management. Either surface mining or underground mining projects may opt to dispose of spent shale in surface impoundments or as fill in graded areas; for surface mining projects, it may be disposed of in previously mined areas. Disadvantages of surface disposal include the use of large land areas; labor-intensive requirements to revegetate the disposal area; dust-control prior to revegetation; and potential impacts on surface water, particularly salinity, from runoff water containing residual hydrocarbons, salts, and trace metals from the spent shale.

While disposal of spent shale back into the underground oil shale mine or a preexisting mine appears initially attractive, various logistical issues may prevent or limit such disposals as well as cause potential problems unique to that disposal technique. For example, mine development design may prevent convenient access to retired portions while the mine is still active. Also, while the potential for leaching of toxic constituents from the spent shale as a result of precipitation or run-on surface water interactions is effectively eliminated, leaching as a result of interaction of groundwater can still be anticipated.²³

²² Butanes formed during upgrading of shale oil are typically mixtures of butane and butylenes. Although potentially saleable products (generally within the boiling range of commercial LPG), these mixtures are more typically used as fuel at the plant site.

²³ It is reasonable to expect that mine dewatering efforts will continue throughout the operational period of the mine but will cease after the mine is shut down and that natural groundwater flow patterns will reestablish, notwithstanding the alterations to flow caused by modifications to the formation. Thus, contact of groundwater with emplaced spent shale can be expected to occur.

Regardless of the disposal option selected, a number of issues need to be addressed, including the structural integrity of emplaced spent shale, an increase in volume (and decrease in density) over raw shale, and the character of leachates from spent shale. Limited research has been conducted on each of these issues.

Studies on the structural properties of spent shale have been performed on the spent shale from the Paraho Retorting project at Anvil Points, Colorado, and summarized in a paper presented at the 13th Oil Shale Symposium held in Golden, Colorado, in 1980 (Heistand and Holtz 1980). The studies concluded that properly wetted and compacted spent shale could be quite stable, even exhibiting the properties of low-grade cements and exhibiting no problems with respect to leaching, autoignition, or fugitive dusting.²⁴ Average structural properties for spent shale from a Paraho AGR are shown in Table A-5.

It has been reported in the literature that as much as 30% expansion in volume can occur in spent shales over the parent raw shale (DOE 1988; Argonne 1990). The exact reasons for this phenomenon are not fully understood. Certainly, some density changes could be expected after removal of the organic fractions. It may also be that CO₂ is being released from decomposing carbonate minerals, and the gas expands the mineral structure as it escapes.

Density changes can be expected to be slightly different for each specific retorting technology, but in all cases, densities of spent shale have decreased over the density of the parent oil shale. A plant producing 50,000 bbl/day from 30 gal/ton oil shale using surface or subsurface mining and AGR may need to dispose of as much as approximately 450 million ft³ of spent shale each year (DOE 1988). Regardless of the degree of compaction that can be accomplished during placement of spent shale, and assuming that the spent shale disposal strategy involves placement

TABLE A-5 Structural Properties of Compacted Paraho AGR Spent Shale

Parameter	Ranges of Values Measured
Compaction (dry density)	1,400–1,600 kg/m ³ (87–106 lb/ft ³)
Permeability	1 x 10 ¹⁷ cm/s (0.1 ft/yr)
Strength (unconfined, compressive)	1,480 kPa (215 psi)
Classifications	
Type	Silty-gravel
Size	30-50% > 4.76 mm (4 mesh) 25-35% < 0.074 mm (200 mesh)
Leaching/autoignition/dusting	No problems identified

Source: Heistand and Holtz (1980).

²⁴ Although the results of this study are encouraging with respect to the short- and long-term impacts of spent shale disposal, it is important to recognize that these results are specific to the spent shale and specific conditions evaluated in this study, and similar results of spent shale from other retorting technologies will not necessarily behave in the same manner.

in retired mine areas to reestablish the original grades and topographies of those areas, as much as 30% of the volume of spent shale would be left once those original grades and topographies were reestablished and would need to be disposed of in virgin areas.

Field data evaluating the leachate character of spent shale have been collected by the EPA and others. Although the data are limited, there appears to be a clear indication that subjecting oil shale to retorting conditions can result in the mobilization of various ionic constituents contained in the mineral portion of the oil shale. Polar organic compounds with moderate to high water solubility formed during retorting and not successfully separated from the spent shale can also appear in spent shale leachates. Tables A-6 and A-7 show typical expected ranges of leachate constituents for spent shale from both in situ and aboveground retorting.

Independent leachate studies have also been carried out on both spent shale disposal piles and piles of raw shale, with emphasis on the potential leachability of arsenic, selenium, molybdenum, boron, and fluorine (as the fluoride ion), all species that are relatively toxic to plants and can be expected to exist as soluble anions under the pH conditions normally encountered in waters interacting with spent shale disposal piles or raw shale stockpiles (i.e., $8 \leq \text{pH} \leq 12$) (Stollenwerk and Runnells 1981). The results of these studies supported the predictions regarding the character of typical leachates from spent shale piles presented in Table A-7.

Another study performed at the Anvil Points Oil Shale Facility in Rifle, Colorado, appeared to identify species that are unique to spent shale leachates and thus possibly useful for monitoring the movements of leachate from spent shale disposal areas (Riley et al. 1981). Soil extracts, surface waters, and groundwaters were analyzed for the presence of water-soluble organic compounds in a drainage area adjacent to a spent shale disposal pile. The C3–C6 alkyipyridines²⁵ were identified in alluvial groundwater samples and in surface waters below a seep and in moist subsoils adjacent to the alluvial sampling well. Extracts of raw shale, crude shale oil, and crude oil from Prudhoe Bay, Alaska, showed no alkyipyridines, however, suggesting that alkyipyridines may be produced during oil shale retorting and become unique constituents of the char on the spent shale. Thus, alkyipyridines may serve as excellent agents for monitoring leachate movements from spent shale piles.

A.5 ONGOING AND EXPECTED FUTURE OIL SHALE DEVELOPMENT TECHNOLOGIES

Limited research into future oil shale development technologies is ongoing, but more is currently being planned. The clear trend established near the end of the last period of major oil shale development activities involved the move to in situ technologies.

²⁵ The parent compound, pyridine, is a cyclic polar hydrocarbon with the formula $\text{C}_5\text{H}_5\text{N}$. It is a flammable liquid with moderate water solubility and a pungent odor. It is a severe eye irritant. Alkyipyridines are derivatives of the parent where one or more hydrogens is replaced by an alkyl group [$\text{C}_n\text{H}_{(n+1)}$].

TABLE A-6 Summary of the Range of Leachate Characteristics of Simulated Spent Shale from In Situ Retorting and from Three AGRs^a

Constituent	Simulated In-Situ Retorts	Surface Retorts ^b
General water quality measures		
pH	7.8–12.7	7.8–11.2
Total dissolved solids	80–>2,100	970–10,011
Major inorganics		
Bicarbonate	22–40	20–38
Carbonate	30–215	21
Hydroxide	22–40	– ^c
Chloride	5.5	5–33
Fluoride	1.2–4.2	3.4–60
Sulfate	50–130	600–6,230
Nitrate (NO ₃)	0.2–2.6	5.1–5.6
Calcium	3.6–210	42–114
Magnesium	0.002–8.0	3.5–91
Sodium	8.8–235	165–2,100
Potassium	0.76–18	10–625
Organics		
Total organic carbon	0.9–38	–
Trace elements		
Aluminum	0.095–2.8	–
Arsenic	–	0.10
Boron	0.075–0.14	2–12
Barium	–	4.0
Chromium	0.002–1.8	–
Iron	0.0004–0.042	–
Lead	0.014–0.017	–
Lithium	0.020–0.42	–
Molybdenum	trace	2–8
Selenium	–	0.05
Silica	25–88	–
Strontium	0.004–8.7	–
Zinc	0.001–0.025	–

^a Concentrations are in mg/L unless otherwise noted.

^b TOSCO, U.S. Bureau of Mines, and Union Oil Company processes.

^c A dash indicates data not available.

Source: EPA (1980).

TABLE A-7 Expected Characteristics of Leachates from Raw Shale Piles and Spent Shale Disposal Piles from Various AGRs^a

Water Quality Parameter	Raw Shale	Spent Shale from Paraho Retort	Spent Shale from TOSCO II Retort
Total dissolved solids	18,000	28,000	55,000
Mo ^b	9	3	9
Boron ^c	32	3	18
Fluoride ^d	16	10	19

^a Concentrations in milligrams per liter (mg/L) unless otherwise noted.

^b Molybdenum predicted to be present as MoO₄²⁻.

^c Boron predicted to be present as B(OH)₃⁰ and B(OH)₄⁻¹.

^d Fluorine predicted to be present as free F⁻¹.

Source: Stollenwerk and Runnells (1981).

A.5.1 Shell Oil Mahogany Research Project

Most of the in situ heating technologies have been in place since the mid-1980s, and early examples invariably involved the use of combustion strategies as sources of heat. There are, however, some novel ongoing research projects that are exploring alternative formation heating techniques. One project of particular potential importance is research being conducted by Shell Exploration and Production (hereafter, Shell), a subsidiary of Shell Oil Corporation, on Shell-owned property located southeast of Rangely, Colorado, in Rio Blanco County. Since 1996, Shell has been working in the Mahogany Zone of the Parachute Creek member of the Piceance Basin, thought to be the richest portion of the Green River Formation, to develop and field-test a novel approach to in situ heating called the in situ conversion process (ICP). ICP involves creating an “ice curtain” or “freeze wall” to isolate a vertically oriented column of the oil shale formation. This is done by encircling the focus area of the formation with wells into which piping is installed for recirculation of a heat-exchange fluid.²⁶ The recirculating heat-exchange fluid removes latent heat energy from the formation immediately adjacent to each of the wells. Ultimately (over a period of years) sufficient heat will be removed from the formation immediately surrounding each of these refrigeration wells so that naturally occurring water in the formation will freeze and form an ice curtain, thereby preventing the subsequent migration of groundwater into that portion of the formation. Then, after removal of any remaining liquid water within the bounded area, additional wells will be installed into which electric resistance heaters will be placed, and the formation will be slowly heated to 650 to 700°F (over the course of 2 years or more). As the process name implies, the intent is to cause a relatively complete chemical conversion of the kerogen to petroleum gases and liquids that will be subsequently

²⁶ The initial research effort involved the use of a brine solution; however, future phases of research may use different heat exchange strategies, such as using aqueous NH₃ solutions coupled with secondary cooling provided by anhydrous NH₂.

recovered using conventional extraction technologies and that will require very little additional processing or modification before being delivered to conventional refineries. An initial review of this project was provided by DOE (2004a).

An artist's conceptual drawing of the ICP is shown in Figure A-7. Figure A-8 is a photograph of the Shell Mahogany Research Project site.

Initial results are very promising. Shell's fact sheet (Shell 2006) characterizes the attributes of this technology in the following manner:

- The process is more environmentally friendly than previous oil shale efforts that were based on mining and retorting.
- ICP has the potential to double the recovery efficiency, as it enables access to much deeper and thicker oil shale reserves.
- ICP can potentially generate transportation fuel products that require considerably less processing.

Early research data appear to support these claims. Recovered products have included gases (hydrogen, natural gas, other combustible gases); (approximately one-third by weight of the total amount recovered) as well as light oils of relatively high quality (typically API 36°); approximately two-thirds by weight. Recovery rates as high as 62% (of recoverable oil) have been observed. Extrapolations from the test scale suggest potential yields (from oil shale deposits of equal richness) of as much as 1 million bbl/acre (i.e., heating of 1 acre of aerial extent of the

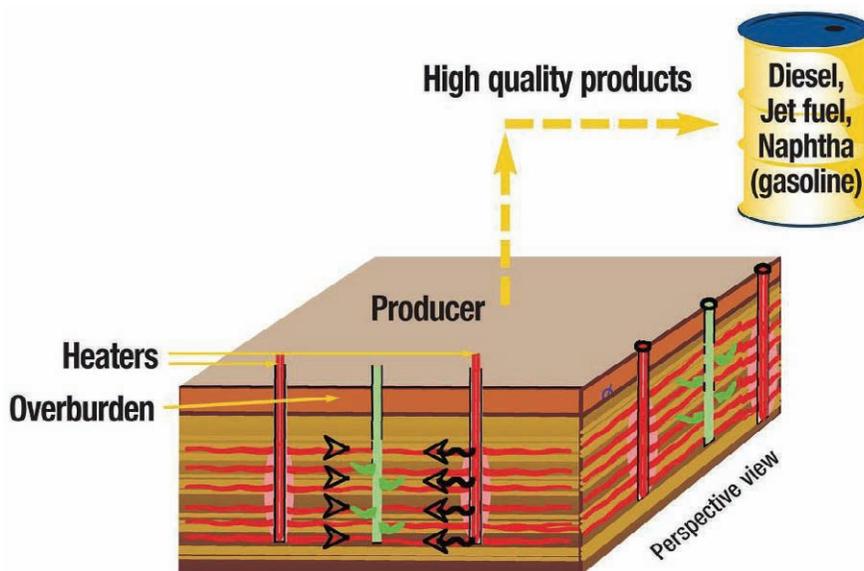


FIGURE A-7 Cross Section of Shell's Patented ICP Technology (Courtesy: Shell Exploration & Production; reprinted with permission)



FIGURE A-8 Shell's Field Research in Rio Blanco County, Colorado (Courtesy: Shell Exploration & Production; reprinted with permission.)

formation throughout the entire depth of the formation present within that 1-acre footprint) (Boyd 2006).

Shell is currently preparing to integrate the research it has been conducting on the individual aspects of this technology (e.g., developing and maintaining a freeze wall, optimizing electric heater technology and rates of formation heating, optimizing product recovery techniques) into a larger-scale demonstration project under the auspices of an RD&D lease recently issued by the BLM. In 1996, Shell carried out a small field test on its Mahogany property in Rio Blanco County, Colorado, by using an in-ground heating process to recover oil and gas from the shale formation. Since then, Shell has carried out four additional field studies on private land near the towns of Rangely, Rifle, and Meeker, Colorado. The most recent test has produced 1,500 bbl of light oil plus associated gas from a relatively small plot. Shell's research is continuing, and Shell has nominated three separate projects under the BLM's oil shale RD&D program to further evaluate its process on public lands.

A.5.2 Oil Tech, Inc., AGR Research

Oil Tech, Inc., a small independent corporation, has been conducting research into aboveground retorting using electric resistance heating. The company maintains a small research site on approximately 2,600 acres of state-owned land approximately 20 mi east-northeast of Bonanza, Utah. This area is also underlain with Green River Formation shale at approximately a 1,000-ft depth but has never been mined. Approximately 70,000 tons of Mahogany Ridge oil shale that had been previously mined from the U-a research tract more than 20 years ago has provided the feedstock for this AGR research and development effort to date. Truckload quantities of run-of-mine shale are delivered periodically to the research site and stockpiled there. The shale is crushed on-site to nominal 1/2-minus size before being introduced by a

conveyor system to the vertical AGR. The AGR is of modular design, composed of a series of individual heating chambers, interconnected and stacked one upon the other, into which shale is loaded from the top. Heating rods extend into the centers of each of these chambers, transmitting heat to the shale in each chamber. Temperatures in each chamber are monitored and controlled by thermocouples. The temperature profile increases from top to bottom of the retort, culminating in the lowest heating chamber attaining a temperature of 1,000°F. An induced draft fan exerts a slight vacuum simultaneously on all of the chambers through a common plenum, providing the principal means of extracting and collecting the gases and volatilized organic products of kerogen pyrolysis released from the shale by the process of fractional vaporization. Pyrolysis products are collected, filtered, and condensed. Spent shale is dumped by gravity from the bottom chamber, allowed to cool, and stockpiled for disposal. Shale moves from the top of the retort to the lowest heating chamber by gravity displacement. The design basis for this retort is 500 tons/h of shale input, resulting in a shale processing rate of approximately 24,000 yd³/day.

The particular advantages of this retort include the following:

- The modular design allows for relative portability and adaptability.
- The process requires no water yet produces approximately 200 lb of water (kerogen pyrolysis as well as free water present in the feedstock) for every ton of shale retorted.
- Heavily insulated enclosure and heating chambers maximize heating efficiency.
- Product separation is easily accomplished.
- Product quality is such that little additional upgrading is required.

Initial results are promising. Yet in these early phases of research, complementary data that are essential to evaluating the overall performance of this retort have not yet been collected in sufficient amounts or detail:

- Mass balances are incomplete to this point.
- Production curves and reaction kinetics have not yet been calculated.
- The fates of sulfur and nitrogen in the kerogen have not yet been investigated.
- Yields have not been precisely calculated; however, spent shale averages 10% residual carbon.
- Leachability, weathering characteristics, and structural features of the spent shale have not been fully investigated.

- No data have been collected regarding the extent to which carbonates are decomposing in the lower (hottest) sections of the retort; however, the acidic character of the pyrolysis water recovered suggests some carbonate decompositions may be occurring.
- Relationships between operating parameters and yield have not been fully explored.

The next phase of the research was scheduled to occur in the spring of 2006 and was to involve a 30-day continuous operation of the retort using the Mahogany Ridge shale that is still at the research site. Over this period, additional data will be collected that will be essential for optimizing operating parameters for the retort, establishing reaction kinetics and thermodynamics to optimize yields, and more precisely evaluating the environmental impacts of the operation, including disposal of spent shale.

As an aside, company representatives have indicated their intent to investigate the possible use of abandoned gilsonite mines for disposal of spent shale and have calculated as much as 5 million ft³ of disposal space to be available in abandoned mines in the immediate area that are located on private lands.²⁷

A.5.3 Future R&D Projects on BLM-Administered Lands

On June 9, 2005, pursuant to its authority to lease federal lands for oil shale development under Section 21 of the Mineral Leasing Act (*United States Code*, Title 30, Section 241 [30 USC 241]), the BLM published a notice in the *Federal Register* (Volume 70, page 33753 [70 FR 33753]) announcing a program wherein companies or individuals could submit proposals to lease 160-acre tracts of BLM-managed land for a period of up to 10 years for the purpose of RD&D of oil shale development technologies. Potential lessees were required to submit a detailed plan of operation development that addressed their proposed development scenario, including their approaches for complying with applicable laws and regulations and environmental protection.

The BLM reviewed each of the proposals that were submitted and selected six to receive further consideration. Upon successful completion of required environmental assessments (EAs), each of the six applicants was awarded a 160-acre lease on which to conduct RD&D of oil shale development technology for a period of up to 10 years, with the potential to extend the lease for another 5 years. Assuming that the RD&D efforts are successful, each RD&D leaseholder will be given the opportunity to exercise a preference right lease, expanding the aerial extent of its BLM lease to a maximum of 5,120 acres, thus facilitating transition from research-scale to commercial-scale operations. Figure A-9 shows the locations of the six RD&D tracts and the associated preference right lease areas. The following sections provide overviews of the six

²⁷ Gilsonite is a natural asphalt deposit that occurs in the United States only in parts of Utah and Colorado. Tectonic movements in the past have resulted in gilsonite being present in vertically oriented fissures, many of which extend to the ground surface. These gilsonite seams were 20 ft or more across and hundreds of feet deep.

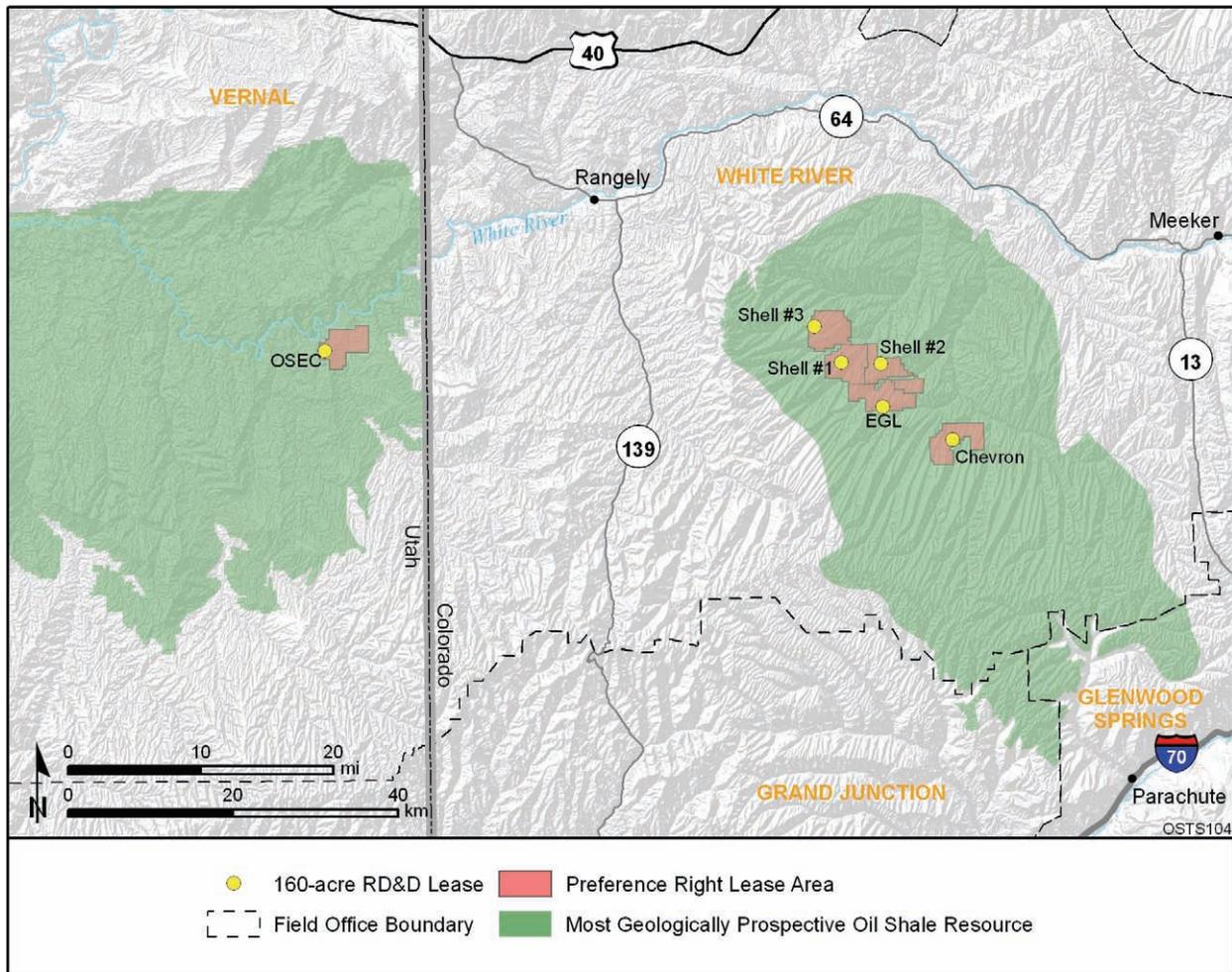


FIGURE A-9 Locations of Six RD&D Tracts and Associated Preference Right Lease Areas

projects on the basis of information published in the EAs (BLM 2006a–c, 2007). Table A-8 lists the hazardous materials, hazardous wastes, and wastewater streams associated with these projects.²⁸

A.5.3.1 Chevron U.S.A., Inc. (Chevron)

The proposed Chevron project would be located in the Piceance Basin of Colorado; information presented here regarding this project is taken from the EA of the proposed activities (BLM 2006a). Chevron’s proposed methodology would be an in situ process for shale oil recovery and production that would be facilitated by applying drilling, fracturing, and in situ heating technologies. This methodology would entail drilling wells into the oil shale formation

²⁸ The following discussions are based on detailed plans of development submitted by each of the RD&D leaseholders. It is understood that those places may be refined or amended (with BLM approval) as research progresses.

TABLE A-8 Hazardous Materials and Wastes, Other Wastes, and Wastewater Associated with the RD&D Projects

Hazardous Materials and Wastes in RD&D Operations

- Fuels and various working and maintenance fluids for vehicles and industrial equipment^a
- Chemicals used in management, purification, and upgrading of gaseous and liquid products
- Spent shale (at Oil Shale Exploration Company [OSEC] site)
- Sludges from purification and sanitary wastewater treatment
- Herbicides
- Containers, dunnage, packaging materials, miscellaneous wastes
- Office-related wastes
- Decommissioning wastes, including fluids for cleaning of industrial equipment, storage containers, and transfer piping
- Products from both in-situ and AGR retorting, including aqueous, gaseous, and organic liquid phases and suspended solids
- Caustic agents, flocculants, and other chemicals common to treatment of industrial wastewaters
- Ammonia chemicals used in the refrigeration system of the Shell sites
- Sulfur compounds generated during the retorting and during secondary processing (hydrotreating)
- Spent catalysts from the hydrotreatment process at the OSEC site

Wastewater from RD&D Initiatives

- Sanitary wastewater
 - Formation water (for 5 sites using in situ retorting)
 - Process water in the formation (a product of kerogen pyrolysis for 5 sites using in situ retorting)
 - Spent drilling fluid and drill cuttings
 - Pyrolysis water (or sour water) with suspended solids, sulfur, heavy metals, and water-soluble organics from retort operation
 - Equipment cleanout activities and boiler blowdown and steam condensate treatments (at those sites where boilers are operated)
 - Wastewaters from well installations
 - Water from mine dewatering (OSEC site)
-

^a Fuels for vehicles and equipment (including diesel and possibly gasoline for emergency power generators), fuels for industrial and comfort heating furnaces, boilers, or other external combustion sources (diesel and/or propane stored in aboveground tanks, or natural gas delivered by pipeline), and vehicle and equipment maintenance fluids (lubricating oils, glycol-based antifreeze, battery electrolytes, hydraulic, transmission, and brake fluids). Fluids are those typically used for maintenance of vehicles and equipment. For on-road vehicles, on-site maintenance is expected to be limited to fluid level maintenance. More substantial maintenance activities (e.g., oil changes, repairs, etc.) would occur at off-site facilities. Also included are dielectric fluids, miscellaneous cleaning solvents, miscellaneous welding gases, and corrosion control coatings (e.g., exterior-grade oil-based paints, two-part epoxy coatings and sealants).

and applying a series of horizontal fracturing technologies. The process would include the generation of hot gases via the in situ combustion of the remaining organic matter in previously heated and depleted zones. These hot gases would then be introduced into the fractured zone to decompose the kerogen into producible hydrocarbons.

The location of the 160-acre lease parcel nominated for Chevron's proposed R&D activities is shown in Figure A-9. Access to the proposed project area would be via Colorado State Highways 13 and/or 64 and County Roads 5 (Piceance Creek), 26, 29, and 69. The proposed lease parcel is situated adjacent to County Road 69 on Hunter Ridge at an elevation of 6,560 to 6,660 ft.

Chevron's proposed methodology for shale oil recovery would apply to an oil shale deposit that is approximately 200 ft thick. This methodology would entail drilling wells into the oil shale formation and applying a series of controlled horizontal fractures within the target interval induced by injecting CO₂ gas into discrete areas of the target interval to effectively rubblize the production zone in a horizontal plane. If necessary, propellants and/or explosives might be directed into the specific horizontally and vertically limited area to facilitate further rubblization of the production zone in order to prepare it for heating and in-situ combustion.

The seven phases of the process would be as follows:

- *Phase 1.* A core would be extracted for use in developing a more comprehensive site-specific understanding of the geology, mineralogy, hydrogeology, and geophysical properties of the formation.
- *Phase 2.* Activity would be directed at identifying and avoiding the existing natural fracture network.
- *Phase 3.* One or more additional test wells would be drilled to confirm and verify the extent of the fracture network.
- *Phase 4.* Additional fracturing of the shale would be facilitated by subjecting the formation to thermal cycles using hot CO₂ gas brought in by CO₂ tanker trucks.
- *Phase 5.* The formation heating process would be initiated by circulating pressurized heated gas through the fractured interval of the formation.
- *Phase 6.* This phase would involve the decomposition of the kerogen and production of shale oil. Before the formation reached the kerogen decomposition temperature, equipment would be installed to collect and process the produced water, gas, and shale oil.
- *Phase 7.* After the recoverable kerogen was extracted from the initial wells, the proposed RD&D program would include integrating the heating process by drilling a new well pattern adjacent to the first and repeating the fracture

process. Hot gases from in situ combustion of the residual organic material remaining in the oil shale would be used to heat the newly fractured zone.

Chevron believes that these fractured zones would have a predominantly horizontal component that would allow for the maintenance of barriers between the production zone and the upper and lower water-bearing units. The detection and avoidance of the natural vertical fractures within the formation is a key component of the proposed technology.

A.5.3.1.1 Groundwater and Surface Water Management. As many as 20 groundwater monitoring wells would be drilled into both the upper and lower water-bearing units as part of a comprehensive groundwater monitoring program incorporated into the design of the proposed process. Additional observation wells may be installed as necessary to further monitor the process.

A.5.3.1.2 Produced Shale Oil and Gas. Storage tanks and facilities would separate the produced gases from the shale oil and water, and liquid streams would then be trucked off-site to separate processing or disposal facilities. Preliminary estimates suggest production rates of 5 or more barrels per day after 1 year of initiating the heating process.

A.5.3.1.3 Storage and Disposal of Materials and Waste. The products used on-site would be typical of the products used in the oil and gas industry (lubricants, diesel fuel, gasoline, lubricating oils, solvents, and hydraulic fluid) and would be used, stored, and disposed of in accordance with all industry standards and practices, as well as in compliance with all federal, state, and local regulations. Smaller quantities of other materials, such as herbicides, paints, and other chemicals, would be used during facility operation and maintenance. Any produced water and/or flush water would be routed to 500-bbl storage tanks for transport off-site to an appropriate disposal facility. Spent caustic would be stored in 50-bbl tanks and transported off-site for disposal. No process wastewater is anticipated in the preliminary phases of the proposed project, but it is expected in the later phases of the program. Drilling fluid returns would be processed by a modularized solids control system to minimize spent drilling fluid generation. This system would produce relatively dry cuttings with minimal associated drilling fluid. The drilled cuttings and fluids would be collected in plastic-lined earthen pits approximately 100 ft by 100 ft with 6 ft of usable depth (8 ft deep). One pit for each of the four proposed well patterns (each of which would consist of 1 producer, 4 injectors, and 12 groundwater wells) would be anticipated. These pits would be kept clean and free of oil and other harmful constituents, constructed in accordance with industry regulations and BLM Gold Book standards and guidelines (DOI and USDA 2006), and designed to meet BLM specifications to deter and/or prevent migratory birds and other wildlife from accessing the contents. Used oil would be handled in accordance with Title 40, Part 279 of the *Code of Federal Regulations* (40 CFR Part 279). A used oil recycler would be contracted to handle all used oil. The proposed in-situ process would not include any aboveground retort activities; therefore, no spent shale would be brought to the surface as a waste product.

The management, maintenance, and disposal of sanitary wastewaters would be contracted through local providers. Solid waste products would be stored in closed, animal-proof containers so as not to attract wildlife and to prevent trash from being blown off-site. All solid waste would be managed, collected, and disposed of in accordance with existing laws and regulations by a local contract provider. Other waste products would be collected and disposed of in accordance with existing laws, stipulations, and regulations.

The proposed in-situ process would not include any aboveground retort activities; therefore, no spent shale would be brought to the surface as a waste product.

Gas produced as a result of the proposed process would be burned as fuel or flared. Produced shale oil would be stored in 100-bbl tanks and transported off-site for processing and subsequent delivery to consumer markets.

A.5.3.1.4 Water Requirements. Table A-9 gives the amount of water consumed; water use would be limited to mixing additives and drilling mud, suppressing dust, and various purposes by personnel. The water required for construction and operation of the proposed process would be purchased from local permitted sources and trucked to the site.

A.5.3.1.5 Staffing. The construction, drilling, and fracturing (Phases 1 through 4) of the proposed process would require from 10 to 100 contractors and employees.

A.5.3.1.6 Utilities. Portable diesel generators would be used to provide the needed power during the preliminary phases of Chevron's proposed RD&D project. Rights-of-way (ROWs) for power, communications, and natural gas would be constructed only if the fracturing phase was considered successful. The power line would be installed on elevated poles along with communication lines. The natural gas pipeline would be installed underground and would enter the proposed lease site by using the same 65-ft-wide combined ROW.

A.5.3.1.7 Noise. The noise generated by this technology would fluctuate with the alternate construction and operation phases of the project. The construction, well drilling, and fracturing phases would generate noise for 2 to 4 months or longer, depending on the success of initial operations. The active retorting phases of the proposed project would generate less noise, but that noise would occur 24 hours a day over the life of the project. The noise-generating equipment for this process would be diesel and gas generators.

TABLE A-9 Estimated Water Needs per Year for Chevron RD&D Site

Year	Estimated Water Needs per Year	
	bbl	ac-ft
2006	36,320	4.68
2007	134,725	17.36
2008	29,445	3.79
2009	254,410	32.79
2010	9,135	1.18
2011	2,135	0.28
2012	233,755	30.13
2013	3,890	0.5
Total	703,185	90.71

Source: BLM (2006a).

Noise generated during the testing phase of the project would be from drill rigs installing monitoring wells and the heating/production wells. Equipment used would be designed to meet applicable Colorado Oil and Gas Conservation Commission allowable noise levels, which are expected to be 50 to 55 A-weighted decibels (dbA) for the tract in a rural/agricultural setting. Noise readings would be taken at the site during operations to verify noise levels.

A.5.3.1.8 Air Emissions. Air pollutant emissions would occur during construction (due to surface disturbance by earthmoving equipment, vehicle traffic fugitive dust, drilling activities, facility construction, and vehicle engine exhaust) and during production (including power generation, product and CO₂ processing, and engine exhausts).

The air pollution emission estimates were based on the best available engineering data assumptions and scientific judgment. However, where specific data or procedures were not available, reasonable but conservative assumptions were incorporated. For example, the air emission estimates assumed that project activities would operate at full production levels continuously (i.e., with no downtime).

A.5.3.1.9 Transportation. The proposed RD&D project would not create additional access onto BLM lands; it would, however, increase traffic on existing roadways and contribute to fugitive dust along the unpaved county roads necessary for access to the site.

A.5.3.2 EGL Resources, Inc. (EGL)²⁹

Information presented here regarding EGL's proposed project is taken from the EA of the proposed activities (BLM 2006b). The EGL project would use an in situ retorting technology to test a 300-ft-thick section of the Mahogany Zone of the Green River Formation in the Piceance Basin of Colorado. The EGL tract is located approximately 27 mi west-northwest of Rio Blanco, Colorado, on a ridge between Ryan Gulch and Black Sulphur Creek at elevations ranging from 6,795 to 6,965 ft (Figure A-9). Both streams are tributaries of Piceance Creek. Vegetation is 48% rolling loam sagebrush and 52% pinyon-juniper. Construction of the RD&D facilities would be accompanied by clearance of 28 acres of rolling loam vegetation and 8 acres of pinyon-juniper vegetation.

In the EGL oil shale process, heat would be introduced by using heated fluids and/or electric heaters near the bottom of the oil shale zones to be retorted. This would result in a gradual, relatively uniform heating of the shale to 650 to 750°F to convert kerogen to oil and gas. It is anticipated that once a sufficient amount of oil is released to surround the heating elements, a broad horizontal layer of boiling oil would continuously release hot hydrocarbon vapors upward and transfer heat to the oil shale above the heating elements.

²⁹ Since the preparation of this PEIS, EGL Resources, Inc. is now American Oil Shale, LLC.

The oil shale that would be tested at the EGL tract is a 300-ft-thick section composed of the Mahogany Zone (R-7) and the R-6 Zone of the Green River Formation, the top of which is at a depth of approximately 1,000 ft. The affected geologic unit would be approximately 1,000 ft long and 100 ft wide. At an estimated richness of 26 gal of oil per ton of shale, the potential amount of oil in the unit to be tested is more than 560,000 bbl per acre. For this test, however, the Mahogany and R-6 Zones would be retorted; the oil shale below these zones, however, could still be retorted at a later date on the 160-acre tract.

A number of heating fluids could be used. It is expected that steam would be used during the initial heating phase of the development. During the later stages of processing, a high-temperature, hot-oil heat-transfer medium, such as Dowtherm, Syltherm, and/or Paratherm, might be used.

To introduce the heating fluids into the oil shale deposit, EGL's technology would involve drilling five cased wells that would vertically penetrate nearly the full length of the oil shale deposit to be tested. Once near the bottom of the oil shale zone, the wells would be drilled horizontally for a distance of about 1,000 ft to the opposite side of the pattern. The wells would then be directed/connected vertically upward through the oil shale and overburden to the surface.

To minimize lost circulation problems in the Uinta Formation and to avoid contaminating any aquifers encountered, the wells would be drilled by using a flooded reverse-circulation method that uses a combination of fresh water and air drilling. Bentonite and polymer would be used to control viscosity and maintain the desired mud weight. Drilling would require about 80 bbl/day of fresh water that would likely be purchased from local sources.

For the RD&D phase of the project, a 25-million-Btu/h trailer or a skid-mounted, direct-fired, forced-circulation, steam-generation boiler would be used to heat the fluids. The boiler would initially be fired by natural gas or propane, but after retorting of the oil shale had begun, the boiler could be fired by gas and oil produced by the retorting process.

A.5.3.2.1 Groundwater Management. To reduce the amount of groundwater infiltrating into the oil shale zone that would be heated, EGL would establish a dewatered zone in the retorting zone. This would be accomplished with four to eight pumping wells surrounding the subsurface retort area. Extracted groundwater would be reinjected downgradient into the equivalent aquifer intervals in order to maintain the regional water table and avoid disturbing baseflow to nearby streams.

Upgradient and downgradient multilevel monitoring wells would be installed to characterize the structure and properties of local aquifers, establish predevelopment baseline groundwater conditions, better define the geology of the oil shale resource, and monitor water quality.

After project completion, pumping and treating of contaminated groundwater would continue until groundwater quality met applicable regulatory standards.

A.5.3.2.2 Produced Shale Oil and Gas. During sustained operation, it is expected that the product would be about 30% gas and 70% light oil, on the basis of heating value. Shale oil produced during test operations would be separated from the gas and water produced with it and stored in tanks at the test site. The shale oil would be trucked to markets in Colorado, Utah, and Wyoming.

A.5.3.2.3 Storage and Disposal of Materials and Waste. Wastewater from the site, including retort water (up to 50 bbl/day), boiler blowdown, and drilling waste, would be trucked to a licensed disposal facility.

A variety of materials typical of the oil and gas drilling and production operations prevalent in the Piceance Basin could be on-site during construction and operations, including lubricants, diesel fuel, gasoline, lubricating oils, solvents, and hydraulic fluid. Smaller quantities of other materials, such as herbicides, paints, and other chemicals, would be used during facility operation and maintenance. These materials would be used to control noxious weeds, facilitate revegetation on disturbed areas, and operate and maintain the facility during the life of the project.

Solid waste (human waste, garbage, etc.) would be generated during construction activities and during operation of the oil shale RD&D facility. Trash would be collected in animal-proof containers and periodically hauled to a sanitary landfill in Rio Blanco County. All other wastes would be collected and disposed of in a manner consistent with existing laws and regulations.

A.5.3.2.4 Water Requirements. Start-up, dust suppression, personnel requirements, and drilling operations would require limited amounts of water (approximately 80 bbl/day for drilling) that would be purchased and trucked to the site from local sources. Makeup water would be required for the boiler to compensate for minor steam losses and to maintain dissolved solids in the boiler at an appropriate level. Water needed for sustained operations would likewise be so acquired or taken from wells on-site if possible. The total volume of water required from outside sources for sustained operation would be approximately 27 bbl/day.

A.5.3.2.5 Staffing. It is estimated that a total of 10 to 40 employees would be required during test operations; most employees would work during daylight hours. During construction of the test facilities and drilling of the test wells, more workers would be needed, and their numbers would vary from 10 to 100, depending on the phase of construction.

A.5.3.2.6 Utilities. A new power line would interconnect an existing power line southwest of the tract and project facilities. The power line would extend approximately 1,760 ft from the southwestern corner of the tract to the existing power line and have a 25-ft-wide ROW. Construction of the power line could disturb as much as 1.0 acre outside the 160-acre tract boundary.

A.5.3.2.7 Noise. Noise generated during the testing phase of the project would be from drill rigs installing monitoring wells and the heating/production wells. Equipment used would be designed to meet applicable Colorado Oil and Gas Conservation Commission allowable noise levels, which are expected to be 50 to 55 dbA for the tract in a rural/agricultural setting. Noise readings would be taken at the site during operations to verify noise levels.

A.5.3.2.8 Air Emissions. Air pollution emissions were estimated on the basis of the best available engineering data assumptions and scientific judgment. However, where specific data or procedures were not available, reasonable but conservative assumptions were incorporated. For example, the air emission estimates assumed that project activities would operate at full production levels continuously (i.e., with no downtime).

Table A-10 gives the estimated NO_x, carbon monoxide (CO), sulfur dioxide (SO₂), PM₁₀, and PM_{2.5}³⁰ emissions associated with EGL's project for both construction and RD&D

TABLE A-10 EGL RD&D Project Air Emissions Summary

Source	Constituent	Emissions	
		lb/day	tons/yr
Construction			
Surface preparation	PM ₁₀	22.95	2.625
	PM _{2.5}	2.08	0.245
Trenching	PM ₁₀	22.90	2.004
	PM _{2.5}	9.8	1.024
Road traffic	PM ₁₀	20.00	2.600
	PM _{2.5}	3.10	0.403
Drill rig engine	PM ₁₀	7.12	1.300
	PM _{2.5}	1.10	0.200
	NO _x	124.40	22.700
	CO	152.90	27.900
Operations			
Boiler	NO _x	222.92	40.500
	CO	40.55	7.400
	SO ₂	832.88	152.000
Road traffic	PM ₁₀	20.00	2.600
	PM _{2.5}	3.10	0.403

Source: BLM (2006b).

³⁰ PM₁₀ = particulate matter with a mean aerodynamic diameter of 10 micrometers (µm) or less; PM_{2.5} = particulate matter with a mean aerodynamic diameter of 2.5 µm or less.

operation scenarios. The emission estimates include both an anticipated maximum daily basis and an annual basis. The construction sources include fugitive dust from road traffic and surface preparation and trenching construction activities and combustion emissions from drill rig operations. Operation sources include combustion emissions from EGL's boiler and fugitive dust from road traffic. Construction and road traffic were modeled by assuming activities would occur during the 7 a.m. to 7 p.m. 12-hour period 5 days per week. The drill rig and boiler were modeled by assuming that these activities would occur continuously.

A.5.3.2.9 Transportation. Workers and contractors would commute to the job site during the test phase. Most traffic would be from Rifle, Meeker, and Rangely on Piceance Creek Road and State Highways 13 and 64. Employer-provided housing is not contemplated for the test phase, but workers whose presence would be required for extended nonroutine testing might be temporarily housed in trailers.

EGL estimates that 10 light and 6 heavy vehicles would travel to the tract each day for a 4- to 6-month duration. During the well drilling and facility construction period, 16 light and 10 heavy vehicles per day would travel back and forth for a duration of 12 to 18 months. During the 3 to 4 years that the facility would be operating, approximately 15 light and 9 heavy vehicles per day would travel back and forth. During shale oil production, 3 tanker trucks would transload railcars at Lacy Siding west of Rifle each day. During reclamation, 2 light vehicles and 1 heavy vehicle would travel to and from the site each day, for a duration of 3 to 4 years. Heavy vehicles would include drill rigs, water trucks, and tanker trucks. Light vehicles would include passenger vehicles, trucks, and vans. Equipment would be obtained locally depending on equipment/drill rig availability, and local services would be used whenever possible. Tankers would be of the standard weight, size, and axle arrangements normally used in the State of Colorado without special permits.

A.5.3.3 Shell Frontier Oil and Gas

Shell is to conduct RD&D projects on three separate 160-acre sites in the northern part of the Piceance Basin in Rio Blanco County, Colorado (Figure A-9); information presented here regarding these projects is taken from the EA of the proposed activities (BLM 2006c). The elevation of the sites ranges between 6,580 and 7,060 ft. The sites would be used to test different methods of shale oil extraction, all of which are based on Shell's proprietary ICP that converts kerogen contained in oil shale into ultraclean petroleum liquids and gas that require less processing to become finished transportation fuels (e.g., gasoline and jet and diesel fuels). The majority of the 160 acres for each of the sites would be impacted through ground disturbance and the construction of buildings and associated infrastructure.

The three sites have the following variations:

- Site 1: ICP—implemented by recovering hydrocarbons from kerogen using self-contained heaters that heat the shale rock.

- Site 2: Two-Step ICP—implemented by initially extracting nahcolite by injecting hot water into the shale and then recovering hydrocarbons through ICP once the nahcolite is removed.
- Site 3: Electric-ICP (E-ICP)—implemented by recovering hydrocarbons from kerogen using bare-wire heaters to heat the rock; some of the heating is created by the flow of electricity through the shale formation.

Site 1 Technology: ICP. For Shell Oil Shale Test Site 1, a freeze wall would be installed to prevent groundwater from flowing into areas where ICP was being used. A series of 150 holes approximately 8 ft apart would be drilled where the freeze wall would be created. The freeze holes would be drilled to a depth of approximately 1,850 ft. A chilled fluid (-45°F) would be circulated inside a closed-loop piping system and into the holes. The cold fluid would freeze the nearby rock and groundwater, and in 6 to 12 months, it would create a wall of frozen ground. The freeze wall would be maintained during both the production and reclamation phases of the ICP project.

After the freeze wall was established, 10 producer holes would be drilled inside the freeze wall and used to remove the groundwater trapped inside the wall. These holes would later be converted to producer holes that would remove the hydrocarbon products. The producer holes would be completed to a depth of approximately 1,675 ft. Pumps would be installed in each hole to bring the product to the surface.

Approximately 30 heater holes would be drilled in the interior of the containment zones, spaced 25 ft apart, and electric heaters would be installed to uniformly heat the otherwise undisturbed hydrocarbon-bearing shale to between 550° and 750°F for a period of several years.

Additional holes would be used to monitor subsurface conditions (e.g., temperatures, pressures, and water levels). The monitoring holes would be placed inside and outside the freeze wall.

After ICP treatment, pumping water into the heated zone would allow recovery of the remaining hydrocarbons. This process, followed by a pump-and-treat process with water and possibly bioremediation, would reduce the amount of hydrocarbons in the heated shale to acceptable levels. Then the freeze wall would be allowed to thaw.

Site 2 Technology: Two-Step ICP. Although significant areas of the Piceance Basin are amenable to ICP technology, the presence of excessive amounts of nahcolite limits the applicability of ICP in portions of the Piceance Basin. Nahcolite, also known as baking soda or sodium bicarbonate, occurs naturally within shale. The process to be used at this test site would be nearly the same as the process to be used in Site 1, with the exception of the extraction of nahcolite prior to removal of hydrocarbon material. The drilling for the freeze walls, heater holes, and extraction would be the same. Removal of the nahcolite prior to implementation of ICP would be required for efficient recovery of both the nahcolite and the petroleum products in

the kerogen. Shell has demonstrated that nahcolite can be solution mined by circulating hot water through the shale. The nahcolite, which is dissolved into the hot water and recovered from the hot water after it is pumped back to the surface, is a product of this process. Removal of the nahcolite increases the permeability and porosity of the remaining rock matrix and significantly improves the thermal efficiency in recovering petroleum from the oil shale when the ICP process is used.

This two-step ICP technology would have a number of energy-saving benefits. The hot water used for nahcolite decomposition could be heated by using waste heat from previous areas where ICP had been implemented. Solution mining would preheat the oil shale in the mined zone to at least 250°F using otherwise wasted heat. The water used for cooling the ICP-treated oil shale would pass through a surface heat exchanger to heat the water used for nahcolite solution mining, providing additional energy savings.

Removing the nahcolite and then dewatering would reduce the mass within the formation that must be heated to ICP temperatures, ultimately reducing the ICP energy requirements. Solution mining the nahcolite would increase the speed at which a heat front would move within the formation, thus reducing the time and energy requirements to produce oil and complete the project.

A freeze wall would be created before initiating nahcolite solution mining and would be maintained through implementation of ICP to contain groundwater. Following the solution mining of the nahcolite, electric heaters would be installed to heat the shale to ICP temperatures, and the solution mining holes would be converted to hydrocarbon production wells. The boundary between the solution-mined nahcolite-ICP region and the remaining nahcolite-bearing strata would provide an impermeable wall, in addition to the freeze wall, to prevent hydrocarbons from migrating out of and water coming into the heated area.

After ICP treatment occurred, the pumping of water into the heated zone would allow recovery of the remaining hydrocarbons. This process, followed by a pump-and-treat process with water and possibly bioremediation, would reduce the amount of hydrocarbons in the heated shale to acceptable levels. Then the freeze wall would be allowed to thaw.

Site 3 Technology: Advanced Heater Test Site (E-ICP). The process used at Site 3 would be nearly the same as that used for Site 1 in terms of the amount and type of drilling and the extraction process. However, the technology for heating would be different. The economics of the ICP process could be improved dramatically if bare electrode heaters were installed that combined both thermal conduction and some heating generated by electricity flow through the shale formation. The bare electrode process is called E-ICP and is a patented in situ heating technology. The project would include about 70 to 100 vertical heaters spaced 20 to 40 ft apart. The bare electrode heaters are about 1,950 ft long and are designed to concentrate most of their heat output in the bottom 1,000 ft. With lower heater well capital costs and greater energy efficiency, E-ICP might increase the oil shale target resource by making much more of the Piceance Basin commercially attractive. Other than the difference in heater technology, the remainder of this process is comparable to the Oil Shale Test (Site 1).

A.5.3.3.1 Groundwater and Surface Water Management. Groundwater monitoring would be conducted at each site to assure compliance with groundwater regulations during and after the project.

Water requirements would vary throughout the life of each project. Water would be trucked to the sites for initial construction and drilling activities. Potable water would be trucked to the sites throughout the life of the facilities.

Once a freeze wall was formed, the water inside the wall would be removed by pumping prior to heating. The groundwater pumped from inside the freeze wall would be injected into wells located outside the freeze wall. The injection wells would be permitted per the requirements of the EPA Underground Injection Control Program.

During heating, water removed from within the freeze wall, along with the hydrocarbon products, would be treated in the processing facilities and recycled or discharged. Water used to recover nahcolite would be recycled into the process. Water that could not be recycled or otherwise used would be treated to appropriate discharge standards in a process water treatment plant and released to surface drainage in a manner consistent with the requirements of a Colorado Department of Public Health and Environment discharge permit.

Groundwater would be used only after state approvals were received. Water wells would be drilled to provide additional water required by the operations, especially during reclamation following completion of hydrocarbon recovery. Reclamation would include flushing and cooling of the shale inside the freeze wall.

During dewatering operations, water from the dewatered zone would be reinjected into the same zone or potentially a different zone at another location on the property.

The pyrolysis process occurring within the approximately 130-ft by 100-ft test area would likely increase the porosity of the oil shale intervals because of the removal of kerogen, resulting in an increase in horizontal hydraulic conductivity. Shell's testing to date, using its heating process on oil shale materials, suggests that the porosity of the rock would increase by about 30% as a result of the pyrolysis of kerogen and removal of oil. There would likely be a minimal increase in the vertical hydraulic conductivity associated with the heating effect on the rock mass. The removal of kerogen is not anticipated to affect the aperture widths of preexisting joints or fractures.

Heating of the oil shale during the pyrolysis phase could increase the vertical permeability of the confining units by enlarging preexisting joints or fractures. The potential consequence of the increased fracture apertures is that groundwater could flow more easily between the Upper and Lower Parachute Creek Units.

Produced Shale Oil and Gas. For Sites 1 and 3, oil and gas production is expected to be approximately 600 bbl/day of oil or 1,000 bbl/day of oil equivalent (oil and gas) at full production. Oil and gas coming to the surface via the previously installed producer holes would

be collected for further processing by traditional processing techniques. Full oil and gas production for the Nahcolite Test Site 2 would be approximately 1,500 bbl/day of oil in the form of untreated synthetic condensate.

The recovered product would include a mixture of liquid hydrocarbons, gas, and water that would be processed further to remove impurities and ready the products for transport off-site or reuse in the recovery process. This recovery process is a typical process used in the oil and gas industry.

The initial processing would separate the recovered product into three streams: liquid hydrocarbons, sour gas, and sour water. The term sour refers to the presence of sulfur compounds and CO₂. Once the three streams were separated, each stream would be further processed to remove impurities. The waste streams generated during much of the processing would be recycled for further treatment.

Nahcolite Recovery (Site 2). The nahcolite mining solution would be pumped to a processing building where the mineral would be removed. The process would remove the mineral from the water in a series of steps; the product would then be dried, stored, and loaded for market. Hot solution would be cooled; because the mineral is less soluble, it would crystallize. Centrifuges would drive off water to concentrate the crystallized material. The water would be reheated and recycled as barren solution. CO₂ would be used to make a final product (sodium bicarbonate).

To minimize disturbance, the groundwater reclamation facilities would be built at the same location as the nahcolite processing facility. Additional engineering evaluations would optimize the site arrangements for these facilities.

Refrigeration System. Appropriate procedures for storage, handling, and emergency response for ammonia chemicals used in the refrigeration system would be included in the Process Safety Management Manual to be developed in accordance with Occupational Safety and Health Administration regulations prior to operation. Emergency response procedures, including procedures for cleanup of spills and notification requirements, would be included in the Emergency Response Plan to be developed prior to operation.

A.5.3.3.2 Storage and Disposal of Materials and Waste. During the course of construction and operation, a variety of by-products and waste materials would be generated at each of the three sites. They would include construction waste, drill hole cuttings, garbage, and miscellaneous solid and sanitary wastes.

Surface construction operations would result in a variety of small waste products that might include paper, wood, scrap metal, refuse, or garbage. These materials would be collected in appropriate containers and recycled or disposed of off-site in accordance with applicable regulations.

Approximately 200,000 ft³ of earth and rock materials would be generated at each test site during drilling operations for the project. Drill cuttings removed from the drilled holes would be dewatered so that the water could be recycled back to the drill rigs. The dewatered cuttings would be placed into a cutting pit. These nontoxic, non-acid-forming drill cuttings would be separated from free water and buried below grade. Burial depth and soil coverage would be sufficient such that the materials would not impede revegetation.

During operation, garbage from the site would be collected in appropriate containers and disposed of off-site. Waste oils, reagents, and laboratory chemicals that were not collected in sumps and treated at the water treatment plants would be recycled or disposed of off-site in accordance with applicable regulations.

The process of producing hydrocarbons from the oil shale would require processing and treating multiple materials. The production complex would include a refrigeration facility, nahcolite recovery process (at Site 2), groundwater reclamation facility, and hydrocarbon processing facility. Spill prevention, control, and countermeasure plans and best management practices would need to be implemented for each stage of production and for all processing facilities. In addition, all waste by-products from the site would need to be properly transported and disposed of according to all rules and regulations regarding the specific waste by-product. These waste by-products would include but not be limited to biosolids effluent and reverse-osmosis reject effluent.

A combination of sanitary waste handling methods would be employed. Some sanitary waste, such as that collected in temporary toilet facilities, might be shipped to an approved facility for off-site treatment and disposal. Any gray water or black water disposed of on-site would be treated in an appropriate sewage processing unit or disposed of according to standards via an approved septic system with a clarifier and drain field.

A.5.3.3.3 Water Requirements. Water requirements would vary throughout the project life. Water uses would include construction, potable water, dust control, drilling, processing, filling, and cooling of the heated interval for reclamation, and rinsing of the zone inside the freeze wall.

Water would be trucked to the site for initial construction and drilling activities. Potable water for personnel consumption would be trucked to the site throughout the life of the facilities.

On-site water would be used for most operational uses and would be supplied from water wells drilled for that purpose. The well would supply water needed for processing and reclamation. Peak pumping demand (250 to 300 gpm, approximately 400 to 480 ac-ft/yr) would occur during the cooling and resaturation phase of the reclamation cycle. If the water well was available during construction and drilling, this water would supplement or replace construction and drilling water trucked to the site.

Water needs for each phase of the operation are outlined below and summarized in Table A-11. The projected water needs are estimates and are subject to change as additional

TABLE A-11 Anticipated Water Usage for the Proposed Shell RD&D Projects^a

Water Requirements	Water Source	Estimated Water Usage		
		Site 1	Site 2 ^b	Site 3 ^b
Potable water	Trucked in	Unknown	Unknown	Unknown
Drilling	Trucked in or groundwater	5 gpm (8 ac-ft/yr)	5 gpm (8 ac-ft/yr)	5 gpm (8 ac-ft/yr)
Construction water	Trucked in	6 gpm (10 ac-ft/yr)	6 gpm (10 ac-ft/yr)	6 gpm (10 ac-ft/yr)
Process water ^c	Groundwater	10 gpm (16 ac-ft/yr)	10 gpm (16 ac-ft/yr)	10 gpm (16 ac-ft/yr)
Nahcolite recovery ^d	Groundwater	NA	7.8 million gal (24 ac-ft/yr) ^e	NA
Reclamation ^f	Groundwater	300 gpm max (480 ac-ft/yr)	300 gpm max (480 ac-ft/yr)	300 gpm max (480 ac-ft/yr)

Source: BLM (2006c).

- ^a Abbreviations: max = maximum anticipated or estimated; NA = not applicable.
- ^b Estimated quantities of water usage for Sites 2 and 3 are based on the plan of development for Site 1.
- ^c Initially, groundwater would be obtained from extraction wells inside the freeze wall (initial dewatering); subsequent process water would come from water wells completed in the Upper Parachute Creek Unit. Process water is treated and recycled again for process operations.
- ^d Groundwater for nahcolite solution mining would largely originate from dewatering of the freeze wall interior area, with additional water from extraction wells in the Upper Parachute Creek Unit located outside of the freeze wall. Water used would be treated and reused.
- ^e Volume estimated is for nahcolite solution mining of a 130-ft by 100-ft pyrolyzed zone footprint. Water would be treated and reused.
- ^f Reclamation includes quenching, cooling, and reclamation of the pyrolyzed zone. Groundwater would originate from extraction wells in the Upper Parachute Creek Unit located outside the freeze wall, and it would be treated and reused.

information becomes available and facility designs are finalized. The current estimate of the amount of water needed for process water is 10 gpm. This water would be supplied from groundwater extracted from either the Uinta or Upper Parachute Creek Units. Water rights required for the project would be acquired prior to start-up of the operation. The combined annual volume of water required for all three sites is unknown at this time and would vary on the basis of when each project started and how each project progressed. On the basis of the assumption that all three sites would operate at the same time for at least 1 year, the combined

process water needs would be a minimum of 30 gpm. This flow rate equates to an annual volume of almost 48 ac-ft/yr.

Construction water would be trucked to the sites as necessary to meet needs for compaction, dust control, and miscellaneous uses. Potable water needed during construction would be brought to the sites. Water required for drilling would be trucked to the sites until water from the on-site water supply well was available to supplement or replace trucked water.

Water would be needed for various processing and operating needs. Water removed with the hydrocarbon products would be treated in the processing facilities and recycled or discharged at a permitted discharge point. The locations of discharge points have not been determined. It is currently anticipated that excess water would be available during the initial processing period as a result of dewatering operations from within the freeze wall containment area and that there would be no need for the water supply well to provide water for processing during this initial period. As processing progressed, there would be a need for additional water.

Water would also be needed to conduct reclamation filling and cooling of the heated interval within the freeze wall containment barrier as well as for rinsing the heated interval. This water would be a combination of recycle water and makeup water from the water supply well, as needed. During reclamation, a water supply would be needed for initial stages of flushing and cooling. Two wells would be completed in the upper Parachute Creek Unit to serve as reclamation water supply wells. However, only one well would be used at a time.

A.5.3.3.4 Staffing. Employment of the maximum number of people at the sites would occur during construction and drilling. An estimated maximum of approximately 720 individuals would be employed at Sites 1 and 3 during the construction and drilling period. At Site 2, an estimated maximum of approximately 700 individuals would be employed during the construction and drilling period. However, because the three test sites would not be developed at the same time, the number of workers employed during construction and drilling would not be cumulative. Once construction was completed, the maximum expected employment would be approximately 155 individuals at Sites 1 and 3 and 150 individuals at Site 2.

A.5.3.3.5 Utilities. Estimates of electricity and gas requirements were not provided in the EA.

A.5.3.3.6 Noise. Noise generated during the testing phase of the project would be from drill rigs installing monitoring wells and from the heating/production wells. Equipment used would be designed to meet applicable Colorado Oil and Gas Conservation Commission allowable noise levels, which are expected to be 50 to 55 dbA for the tract in a rural/agricultural setting. Noise readings would be taken at the site during operations to verify noise levels.

A.5.3.3.7 Air Emissions. The air pollution emission estimates for each of the three Shell sites were based on the best available engineering data assumptions and scientific judgment. However, when specific data or procedures were not available, reasonable but conservative assumptions were incorporated. For example, the air emission estimates assumed that project activities would operate at full production levels continuously (i.e., with no downtime).

A.5.3.3.8 Transportation. Access to each of the three sites would be provided by constructing an access road to connect the site to existing county roads. Initial construction activities would include development of the site access road to a running width of approximately 24 ft to allow heavy equipment to travel in two directions. The access road would be paved with asphalt for the 24-ft width and include appropriate ditches and culverts to maintain drainage control. Access to the sites from public roads would be restricted by an entry gate. An estimated 300 to 650 vehicles per day would access the sites during construction.

A.5.3.4 Oil Shale Exploration Company (OSEC)

OSEC proposes to lease the White River Mine site (160 acres) in Uintah County, Utah (Figure A-9), in order to conduct a three-phase RD&D project to test shale oil recovery by using the ATP retort technology and by providing incoming natural gas via a pipeline through the “western” ROW alignment. Information presented here regarding this project is taken from the EA of the proposed activities (BLM 2007). The ATP system is a thermal process for pyrolyzing oil shale. The primary unit is the ATP Processor, which is a modified horizontal rotary kiln. The ATP Processor has four internal zones in which the four stages of ore processing occur: (1) preheating of the feedstock, (2) pyrolysis of the oil shale under anaerobic conditions, (3) combustion of coked solids to provide the process heat requirements, and (4) cooling of the combustion products by heat transfer to the incoming feed.

Phase 1 of the project is expected to last approximately 11 months. During this time, OSEC would remove approximately 1,000 tons of oil shale from the White River Mine’s on-site surface stockpile for processing at the existing ATP pilot plant unit in Calgary, Alberta, Canada.

The 1,000 tons of shale would be transported by truck from the 160-acre lease out of the project area to a gravel pit in Uintah County, where it would be crushed to design specifications ($-3/8$ in.). The crushed shale (total 1,000 tons) would be trucked to Calgary for testing by UMATAC in its 4-ton/h ATP Processor pilot plant. During Phase 1, no crushing of oil shale would be performed within the White River Mine lease area.

It is expected that about 650 bbl of raw shale oil would be produced from the 1,000 tons of oil shale processed. Approximately 800 tons of non-Resource Conservation and Recovery Act (RCRA) hazardous spent shale would be produced from the processing of the 1,000 tons of feed shale. Samples of this material would be retained for testing and analysis in Canada and the United States. The remaining spent shale would be disposed of in a licensed landfill in Alberta, or it would be stored on-site in Alberta pending identification of a beneficial reuse.

No fuel storage, office facilities, overnight accommodations, toilets, or drinking water supply would be established at the White River Mine lease area during Phase 1. Although the loading and trucking operation is not expected to be dusty, some minor amounts of water might be required to control dust during the loading of the shale feed into the trucks at the White River Mine. All water required for this phase would be trucked in by a local supplier and dispensed from a water truck. No water rights would be needed for this phase of work. The fugitive dust emissions associated with loading the oil shale from the existing surface stockpile, road dust, and exhaust emissions from the front-end loader and trucks (short-term activities) would be the only air emissions associated with the Phase 1 operations within the 160-acre leasehold.

Phase 2 of the RD&D project would last about 14 months and involve the mobilization of the UMATAC 4-ton/h ATP Processor pilot plant and associated equipment from Calgary to the White River Mine lease area. Shale for processing would initially come from the existing surface stockpiles. OSEC would reopen the White River Mine and begin mining fresh oil shale for use as feed to the plant during the latter stage of Phase 2.

It is currently anticipated that Phase 2 construction would involve a relatively small amount of new construction work on-site. The trailer-mounted ATP pilot plant would be mobilized from Calgary and set up on-site on an impervious base pad. A fuel tank area would be constructed with a liner and an embankment surrounding it. An additional aboveground storage tank area would be established for shale oil product storage and load out; these tanks would sit on a liner within an embankment. There would also be a facility for on-site crushing, stockpiling, and ore handling.

The major Phase 2 construction activity would involve reopening the mine and constructing a spent-shale disposal area. Approximately 10,000 tons of oil shale would be processed through the ATP Processor pilot plant during Phase 2.

Phase 3 of the RD&D project would involve the design, permitting, and fabrication of a 250-ton/h ATP Processor demonstration plant and construction of that plant within the 160-acre lease area. OSEC plans on 2 years to permit, engineer, and construct the plant. Also, the mine would be developed sufficiently to support the mining of 1.5 million tons/yr of oil shale, which would be used as feed for the operation of the demonstration plant. Following commissioning, the plant would operate for 2 years so enough operational, technical, environmental, and financial information could be compiled to make an informed decision on whether to proceed to a commercial project.

Preparation for Phase 3 operations would involve significant on-site construction activity, particularly related to the new 250-ton/h ATP demonstration plant and all the ancillary equipment. Many of the demonstration plant components would be fabricated elsewhere and transported to the site for final assembly and erection. This would lessen the amount of laydown space required during construction and the number of construction workers needed at the site. The most significant permanent surface feature constructed during Phase 3 would be the 38-acre storage area for containing the 2.2 million tons of spent shale that could be generated during this phase of work.

Approximately 2.7 million tons of oil shale would be processed through the ATP Processor demonstration plant during Phase 3. The source of the shale feed would be the reopened mine. All mined shale would be stockpiled and crushed/blended at the surface within the 160-acre lease area. It is expected that all shale mined would be processed (i.e., there would be no fines rejects produced during the shale crushing activities).

In addition to the construction of the ATP Processor plant and ancillary equipment on the 160-acre lease, it would be necessary to construct/install natural gas, electric power, and water lines along the proposed ROWs.

A.5.3.4.1 Storage and Disposal of Materials and Waste. During Phase 2, approximately 8,000 tons of spent shale would be generated and placed in a small valley impoundment, less than 2 acres in size. The impoundment would be bermed, and surface water runoff would be directed around the impoundment to prevent stormwater runoff from other areas of the lease from contacting the pile of spent shale. Overall, flow would be directed to the gully near the dam.

During Phase 3, 2.2 million tons of spent shale would be produced and disposed of at a 38-acre storage area. Minor amounts of construction-related wastes would also be generated during the rehabilitation of existing structures and the construction of new facilities and structures associated with the Phase 3 250-ton/h demonstration work. Such wastes could include scrap metal or wood, concrete, and miscellaneous trash from the packaging of the construction materials. These materials would be temporarily staged in roll-offs and trucked to an off-site solid waste facility.

Shale oil typically contains 0.5 to 0.75% sulfur (OTA 1980b). Sulfur compounds generated during retorting and secondary processing (hydrotreating) are primarily in the form of H₂S, with lesser amounts of mercaptans. Through the treatment train process (i.e., air emission control devices and/or wastewater treatment), sulfur-bearing solid wastes would be generated.

The hydrotreatment process would generate a variety of waste products, including sulfur-containing residuum and spent catalysts. Spent catalyst, which is considered a listed RCRA hazardous waste (K071), would consist of aluminum silicate and various metals (typically cobalt, molybdenum, nickel, and/or tungsten). These waste materials would be disposed of at an appropriate off-site disposal facility. Prior to disposal, the wastes would be contained in waste storage areas built with appropriate spill containment features.

Occasionally, waste oils would be generated from equipment maintenance activities during Phases 2 and 3. In addition, the hydrotreatment process and wastewater treatment of the process waters would produce large volumes of oily sludges. (Since the exact nature of the hydrotreatment has not been finalized, it is not possible to reasonably predict the volume of such materials that would be produced during Phase 3.) All such materials would be temporarily stored on the 160-acre lease site and trucked off-site to a licensed facility for treatment and disposal.

Mine Water. During Phase 2, the mine would be dewatered as part of the reopening process. Mine water of good quality would be discharged to the existing retention dam area. The exact volume of such water is not known, but it would amount to more than 2 million gal if the water was pooled to the top of the Birds Nest Aquifer. Mine water below the bulkhead might contain levels of petroleum-based compounds that would have resulted from contact with the oil shale and the bitumen seep in the lower portion of the mine. This water would likely be trucked off-site for treatment and disposal at an approved facility.

During mining operations, water from dewatering of the mine could contain petroleum-based compounds. During Phase 2 operations, this water would be temporarily stored in tanks. Depending on test results, it would then either be discharged to an on-lease drainage channel to flow toward the retention dam area (if the test showed that it met agreed-upon discharge criteria) or trucked off-site. The appropriate frequency of testing the water would be stipulated on the basis of the results from the initial test of mine water conducted prior to the reopening of the mine.

During Phase 3, mine water that did not meet water quality standards would be treated through the process wastewater treatment system, along with wastewater from the air treatment and hydrotreatment processes.

Connate and Retort Water. Approximately 150 tons (35,700 gal) of connate water (water trapped in shale pore spaces) would be generated during Phase 2, and 40,000 tons (9.5 million gal) would be generated during Phase 3. The connate water might be suitable for use in remoistening and cooling the spent shale without treatment. If the connate water did not meet appropriate criteria, it would be trucked off-site for treatment and disposal during Phase 2 RD&D activities and would be treated in a wastewater treatment system on the 160-acre lease site during Phase 3.

Approximately 200 tons (48,000 gal) of retort water (chemically bound moisture in the shale) would be generated during Phase 2, and approximately 55,000 tons (13.2 million gal) would be generated during Phase 3. Retort water often contains phenols, H₂S, or trace levels of petroleum constituents that might require treatment before they could be used for cooling and moistening spent shale or discharged to an existing retention dam. During Phase 2, all retort water would be temporarily stored on the lease site, tested, and, if it met appropriate water quality criteria, used to cool the spent shale or trucked off-site for treatment and disposal. During Phase 3, a wastewater treatment facility on the 160-acre lease site would be used to treat the retort water to remove H₂S, NH₃, phenols, and other constituents of concern. It is anticipated that following treatment, nearly all of the water would be used to cool and moisten the spent shale or otherwise reused in the process. Small amounts of water not needed for cooling and moistening the spent shale might be discharged to a drainage feature leading to the retention dam area.

Process washdown is water that is regularly used to clean the retort and other equipment during the on-site operations. Such water might contain high levels of sediment, and it might also contain oily residues from the equipment.

All the sour water generated during Phase 3 would be stored and treated on-site prior to being used for controlling dust or moistening the spent shale. Depending on chemical analysis results, the sour water treatment might include stripping of NH_3 and H_2S , followed by biological aeration.

Sanitary Sewage Effluent. During routine daily operations in Phase 2 and Phase 3, workers would generate sanitary wastes. These, along with other wash water, would be processed in an existing closed sanitary wastewater treatment system on the 160-acre lease site. Any sanitary sewage generated before the repair and testing of the on-site system would be collected and trucked to an off-site wastewater treatment plant.

A.5.3.4.2 Produced Shale Oil and Gas. Approximately 6,000 bbl of raw shale oil would be produced during Phase 2. All oil produced would be temporarily stored in aboveground tanks located within the 160-acre lease area before being trucked to an off-site facility for sale.

Approximately 1.8 million bbl of raw shale oil is expected to be produced during Phase 3. It is anticipated that this oil would be hydrotreated on-site to produce a synthetic crude oil product. The synthetic crude oil would be temporarily stored in aboveground tanks on-site. The product would be trucked off-site to a refinery or delivered to a nearby pipeline that would have the capacity and specifications to accept this upgraded shale oil.

A.5.3.4.3 Water Requirements. The amount of makeup water required in Phase 2 for processing the oil shale is estimated to be approximately 2 bbl (84 gal) per ton of shale feed, half of which would be needed to cool and moisten the spent shale. This means that the total makeup water requirement for Phase 2 would be 20,000 bbl of water. Small amounts of additional water might be required on-site for drinking, cooking, laundry, and toilet facilities for the Phase 2 workforce. All Phase 2 water needs (potable and process) would be trucked to the site by a local supplier that had the appropriate water rights. The water would be stored in aboveground tanks within the 160-acre lease area. No water rights would be needed by OSEC for this phase of work.

The total amount of Phase 3 water needed to process the oil shale (i.e., makeup water) is estimated to be on the order of 4.1 million bbl. This is equivalent to a peak water demand of 380,000 gal/day while the processing plant is operating. Currently, it is proposed that the makeup water be supplied from water wells established in the Birds Nest Aquifer (two to three wells located in the northwestern portion of the 160-acre lease site), from wells in the White River alluvial deposits (wells installed as part of the earlier mine development activities that are north of the 160-acre lease), or from a direct intake in the White River. Water pumped from these sources would be stored in aboveground tanks on-site.

A potable water tank would be placed near the trailers to supply domestic needs; the potable water would be trucked to the site. A process water tank with a capacity of about 750 bbl would be installed next to the plant.

A.5.3.4.4 Staffing. It is estimated that the operational workforce at the site during Phase 3 operations would be composed of approximately 120 individuals. Offices and shower and toilet blocks would be provided on-site.

A.5.3.4.5 Utilities. Electricity required for the mine, pilot plant, and on-site accommodations would be provided by diesel generators established within the 160-acre lease area (1-MW total capacity). Propane would be used to provide heat to the process during start-up periods as well as heat for office and field trailers. Also, diesel fuel would be used to run surface and underground mine vehicles and equipment on-site. All diesel and propane fuel would be trucked in and stored on-site in aboveground tanks. The diesel tanks would be placed in lined and bermed containment areas.

Up to 14 MW of electric power could be required at the site during Phase 3, and it is assumed that electric power to the site would be provided from the grid via a new 138-kV transmission line. Emergency diesel generator capacity would also be provided on-site to meet both plant backup and mine operational and safety requirements.

Natural gas or propane would be required for the operation of the ATP Processor demonstration plant. Further studies are required to assess whether it would be feasible to truck in propane gas or whether a pipeline connection to a natural gas supply would be required.

A.5.3.4.6 Air Emissions. The sources of air emissions would vary during the three phases of RD&D activities on the site. These sources are listed by phase in Tables A-12 through A-16. The ATP unit and the hydrotreatment unit would be fully permitted under the Clean Air Act and have all the emission control equipment required by the Act.

Greenhouse gas emissions would be generated on-site during both Phase 2 and Phase 3 operations. They would originate mostly from the retorting of the shale feed (see Tables A-15 and A-16, respectively). Additional greenhouse gas emissions would be produced from the burning of coal at the Bonanza Power Plant to generate electric power.

A.5.3.5 Syntec Energy

Syntec Energy is a small, privately held R&D company. The Syntec process uses a rotary kiln in conjunction with syngas derived from coal gasification to pyrolyze the shale and produce shale oil. Successful bench tests of this technology have been conducted by the University of Utah.

TABLE A-12 Phase I Estimated Emissions

TABLE 4-3 Phase I Estimated Emissions							
Emission Point	Estimated Emissions Summary (tons/Phase I)						
	NO _x	SO ₂	CO	VOC	PM ₁₀	CO ₂	HAPs
Diesel Vehicle Emissions ¹	3.17	0.50	0.78	0.22	0.11	0.00	0.00
Truck Loading/Unloading ²	--	--	--	--	0.000008	--	--
Storage Pile ²	--	--	--	--	0.06	--	--
Total	3.17	0.50	0.78	0.22	0.17	0.00	0.00

¹ Emission factors from <http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html>

² Emission factors from USEPA AP-42 Chapter 11.19.2, *Crushed Stone Processing and Pulverized Mineral Processing*, August, 2004 for truck unloading of fragmented stone. Assumed controlled emissions using wet suppression. Aggregate storage emission factor from US EPA FIRE 6.25

Source: This table is reproduced as contained in BLM (2007).

TABLE A-13 Phase 2 Estimated Emissions

TABLE 4-4 Phase 2 Estimated Emissions						
Emission Point	Estimated Emissions Summary (tons/Phase 2)					
	NO _x	SO ₂	CO	VOC	PM ₁₀	HAPs
ATP System Operation ¹	0.55	1.23	8.21	0.14	0.55	--
Start-Up Burner ²	0.086	0.000072	0.014	0.0023	0.0027	0.000033
Flaring of flue gas ³	--	--	0.26	5.98	--	--
Diesel Generator ⁴	7.73	1.44	0.86	0.91	1.44	0.27
Diesel Storage Tank ⁵	--	--	--	0.0062	--	--
Shale Crushing/Screening ⁶	--	--	--	--	0.026	--
Truck Loading/Unloading ⁶	--	--	--	--	0.00008	--
Stockpiled Shale ⁶	--	--	--	--	0.48	--
ANFO Blasting ⁷	0.032	0.004	0.126	--	--	--
Shale Oil Storage Tank ⁸	--	--	--	0.73	--	--
Unpaved On-site Roads ⁹	--	--	--	--	0.48	--
Total	8.40	2.67	9.47	7.77	2.98	0.27
<p>¹ Estimated concentration data provided by UMATAC based on a pilot project in Canada. Emissions assumed a 95% control on CO, VOC, and SO₂, and a filter bag for PM control. The CO₂ formed during oxidation of CO, assuming 100% conversion, was added to the total amount of CO₂. HAP emissions are not known at this time. A portion of these emissions will be due to the start-up burner. To be conservative, assumed the start-up burner emissions are separate.</p> <p>² Assumed a 24 hour start-up period, required 15 times over the course of the phase. Assumed a natural gas burner consuming 48 MMBtu per start-up. A portion of these emissions may be included in the ATP data; however, to be conservative, assumed the start-up burner emissions are separate. Emission factors are from USEPA AP-42, Chapter 1.5, <i>Liquefied Petroleum Gas Combustion</i>, October 1996; HAP emissions were taken from USEPA AP-42 Chapter 1.4, <i>Natural Gas Combustion</i>, July 1998.</p> <p>³ Estimated based on flare gas from previous pilot study conducted on similar ATP60 plant. Assumed a 98% destruction efficiency based on USEPA AP-42 Chapter 13.5, <i>Industrial Flares</i>, September 1991. The amount of CO converted to CO₂ in the flare is included in the CO₂ emission value.</p> <p>⁴ Estimated assuming 592,000 gal of diesel will be needed for length of Phase 2. To be conservative, assumed all diesel is used in diesel-fired generators; however, some (~22,000 gal) will be used in the haul trucks and other unknown underground equipment. In order to comply with concentration thresholds, a CO and NO_x APCD device may need to be installed; therefore, a 85% and 90% control efficiencies for NO_x and CO were assumed. Emissions factors were obtained from typical Cummins 1 MW diesel generator specifications; CO₂ emission factor was from USEPA AP-42, Chapter 3.3, <i>Gasoline and Diesel Industrial Engines</i>, October 1996.</p> <p>⁵ Working and breathing losses for 15,000 gal. tanks with a total throughput of 592,000 gallons (570,000 gal for power generation, 22,000 gal for the mine work) for the Phase, estimated using EPA Tanks4.0 program.</p> <p>⁶ Emission factors from USEPA AP-42 Chapter 11.19.2, <i>Crushed Stone Processing and Pulverized Mineral Processing</i>, August, 2004. Assumed controlled emissions using wet suppression. Assumed 2 intermediate conveying transfer points between one primary crusher, one secondary crusher, and one screener. Aggregate storage emission factor from US EPA FIRE 6.25</p> <p>⁷ Emission factors are from USEPA AP-42 Chapter 13.3, <i>Explosives Detonation</i>, February 1980.</p> <p>⁸ Working and breathing losses for a 31,500 gal tank used to store the produced shale oil with a total project throughput of 6,400 gal, estimated using EPA Tanks4.0 program.</p> <p>⁹ Estimated PM₁₀ emissions from unpaved vehicle traffic on-site using USEPA AP-42, Chapter 13.2.2, <i>Unpaved Roads</i>, December 2003; assumed a total of 50 miles traveled during Phase 2 for a 200 ton truck to gather 10,000 tons of shale oil (200 tons at a time) and transport it back to the ATP. Although PM_{2.5} were not modeled due to lack of emission factors, even if all PM₁₀ emissions were in the form of PM_{2.5} emissions would be well below the PM_{2.5} NAAQS.</p>						

Source: This table is reproduced as contained in BLM (2007).

TABLE A-14 Phase 3 Estimated Emissions

TABLE 4-7 Phase 3 Estimated Emissions						
Emission Point	Estimated Emissions Summary (tons/Phase 3)					
	NO _x	SO ₂	CO	VOC	PM ₁₀	HAPs
ATP System Operation ¹	126.97	285.67	1,904.49	31.74	13.34	--
Start-Up Burner ²	17.75	0.015	2.99	0.47	0.56	0.0068
Electrical Needs (14 MW) ³	207.79	34.94	--	--	--	--
Hydrogen Plant Reformer ⁴	5.15	0.06	8.64	0.57	0.78	0.00
Flaring of flue gas ⁵	--	--	8.19	186.94	--	--
Diesel Storage Tank ⁶	--	--	--	0.024	--	--
Shale Crushing/Screening ⁷	--	--	--	--	7.14	--
Stockpiled Shale ⁷	--	--	--	--	132.00	--
Truck Loading/Unloading ⁷	--	--	--	--	0.02	--
ANFO Blasting ⁸	14.88	1.75	58.63	--	--	--
Diesel Combustion ⁹	870.81	24.25	145.50	15.43	24.25	4.52
Shale Oil Storage Tank ¹⁰	--	--	--	9.19	--	--
Unpaved On-site Roads ¹¹	--	--	--	--	167.66	--
Total	1243.34	346.69	2,128.44	244.36	345.75	4.52
<p>¹ Estimated concentration data provided by UMATAC based on a pilot project in Canada. Emissions assumed a 95% control on CO, VOC, and SO₂, and a filter bag for PM control. The CO₂ formed during oxidation of CO, assuming 100% conversion, was added to the total amount of CO₂. HAP emissions are not known at this time. A portion of these emissions will be due to the start-up burner. To be conservative, assumed the start-up burner emissions are separate.</p> <p>² Assumed a 24 hour start-up period, required 50 times over the course of the phase. Assumed a natural gas burner consuming 3,000 MMBtu per start-up. A portion of these emissions may be included in the ATP data; however, to be conservative, assumed the start-up burner emissions are separate. Emission factors are from USEPA AP-42, Chapter 1.5, <i>Liquefied Petroleum Gas Combustion</i>, October 1996; HAP emissions were taken from USEPA AP-42 Chapter 1.4, <i>Natural Gas Combustion</i>, July 1998.</p> <p>³ Emissions were estimated based on the average 2000-2005 Bonanza I Power Plant emissions data from the USEPA Clean Air Markets. Between 2000 and 2005, the power plant required on average 4,996 MMBtu/hr. The additional power needed for Phase 3 would result in a maximum increase in usage of 3%. Assumed 3% of the average power plant emissions provided on the Clean Air Markets website would be emitted due to operation of Phase 3. Data on CO, VOC, PM₁₀ and HAPs was not provided on the website.</p> <p>⁴ Emissions were estimated assuming a 5.8 MW reformer fueled on natural gas and USEPA AP-42 Chapter 1.4, <i>Natural Gas Combustion</i>, July 1998. These emissions only account for an estimate of the hydrogen reformer; additional combustion devices that may be needed are not included or known at this time. The hydrotreating process is not anticipated to result in emissions not already accounted for in the ATP emissions estimate.</p> <p>⁵ Estimated based on previous test run conducted on similar ATP60 plant scaled up for the 250 ton/yr processor, assuming only 50% of the off-gas is flared. This value is highly conservative given the flaring may only occur during emergency situations and/or the off-gas may be used instead to further fuel the ATP.</p> <p>⁶ Working and breathing losses for 15,000 gal. tanks with a total throughput of 10,000,000 gallons for the Phase, estimated using EPA Tanks 4.0 program.</p> <p>⁷ Emission factors from USEPA AP-42 Chapter 11.19.2, <i>Crushed Stone Processing and Pulverized Mineral Processing</i>, August, 2004. Assumed controlled emissions using wet suppression. Assumed 2 conveying transfer points. Aggregate storage emission factor from US EPA FIRE 6.25</p> <p>⁸ Emission factors are from USEPA AP-42 Chapter 13.3, <i>Explosives Detonation</i>, February 1980.</p> <p>⁹ Diesel fuel will be used mostly in underground haul trucks and other mining equipment. Some surface equipment or standby emergency generator may be used. To be conservative, the estimated 10 million gallons of diesel was assumed to be burned in a generator.</p> <p>¹⁰ Working and breathing losses for shale oil storage tanks with a total project throughput of 75,348,000 gal, estimated using EPA Tanks 4.0 program.</p>						

Source: This table is reproduced as contained in BLM (2007).

TABLE A-15 Phase 2 Greenhouse Gas Emissions

TABLE 4-5. Phase 2 Greenhouse Gas Emissions			
Emission Point	Phase 2 (tons\Phase 2)		
	CO₂	Methane	Carbon Equivalence
ATP Processor Operation ¹	2,296.86	--	626.42
Start-Up Burner ²	56.56	--	15.42
Flaring of flue gas ³	128.16	--	34.95
Diesel Generator ⁴	6,807.48	--	1,856.58
Mine Opening Methane ⁵	--	10.52	7.89
Total	9,289.05	10.52	2,541.27
¹ Estimated concentration data provided by UMATAC based on a pilot project in Canada. The CO ₂ formed during oxidation of CO, assuming 100% conversion, was added to the total amount of CO ₂ . A portion of these emissions will be due to the start-up burner. To be conservative, assumed the start-up burner emissions are separate.			
² Assumed a 24 hour start-up period, required 15 times over the course of the phase. Assumed a natural gas burner consuming 48 MMBtu per start-up. A portion of these emissions may be included in the ATP process data; however, to be conservative, assumed the start-up burner emissions are separate.			
³ Estimated based on flare gas from previous pilot study conducted on similar ATP60 plant. Assumed a 98% destruction efficiency based on USEPA AP-42 Chapter 13.5, <i>Industrial Flares</i> , September 1991. The amount of CO converted to CO ₂ in the flare is included in the CO ₂ emission value.			
⁴ Estimated assuming 592,000 gal of diesel will be needed for length of Phase 2. To be conservative, assumed all diesel is used in diesel-fired generators; however, some (~22,000 gal) will be used in the haul trucks and other unknown underground equipment. CO ₂ emission factor was from USEPA AP-42, Chapter 3.3, <i>Gasoline and Diesel Industrial Engines</i> , October 1996.			
⁵ Estimated value provided by OSEC, assumes 5,000 cf CH ₄ /day over the course of the Phase 2.			

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TABLE A-16 Phase 3 Greenhouse Gas Emissions

TABLE 4-8			
Phase 3 Greenhouse Gas Emissions			
Emission Point	Phase 3 (tons/Phase 3)		
	CO ₂	Methane	Carbon Equivalence
ATP Processor Operation ¹	532,985.79	--	145,359.76
Start-Up Burner ²	11,680.33	--	3,185.54
Electrical Needs (14 MW) ³	126,049.52	--	34,377.14
Hydrogen Plant Reformer ⁴	12,349.23	--	3,367.97
Flaring of flue gas ⁵	4,004.99	--	1,092.27
Diesel Combustion ⁶	114,991.18	--	31,361.23
Mine Opening Methane ⁷	--	472.73	354.55
Total	802,061.04	472.73	219,098.46
¹ Estimated concentration data provided by UMATAC based on a pilot project in Canada. The CO ₂ formed during oxidation of CO, assuming 100% conversion, was added to the total amount of CO ₂ . A portion of these emissions will be due to the start-up burner. To be conservative, assumed the start-up burner emissions are separate.			
² Assumed a 24 hour start-up period, required 50 times over the course of the phase. Assumed a natural gas burner consuming 3,000 MMBtu per start-up. A portion of these emissions may be included in the ATP process data; however, to be conservative, assumed the start-up burner emissions are separate.			
³ Emissions were estimated based on the average 2000-2005 Bonanza I Power Plant emissions data from the USEPA Clean Air Markets. Between 2000 and 2005, the power plant required on average 4,996 MMBtu/hr. The additional power needed for Phase 3 would result in a maximum increase in usage of 3%. Assumed 3% of the average power plant emissions provided on the Clean Air Markets website would be emitted due to operation of Phase 3.			
⁴ Emissions were estimated assuming a 5.8 MW reformer fueled on natural gas and USEPA AP-42 Chapter 1.4, <i>Natural Gas Combustion</i> , July 1998. These emissions only account for an estimate of the hydrogen reformer; additional combustion devices that may be needed are not included or known at this time. The hydrotreating process is not anticipated to result in emissions not already accounted for in the ATP processor emissions estimate.			
⁵ Estimated based on previous test run conducted on similar ATP60 plant scaled up for the 250 ton/yr processor, assuming only 50% of the off-gas is flared. This value is highly conservative given the flaring may only occur during emergency situations and/or the off-gas may be used instead to further fuel the ATP.			
⁶ Diesel fuel will be used mostly in underground haul trucks and other mining equipment. Some surface equipment or standby emergency generator may be used. To be conservative, the estimated 10 million gallons of diesel was assumed to be burned in a generator.			
⁷ Estimated value provided by OSEC, assumes 50,000 cf CH ₄ /day over the course of the Phase 3.			

Source: This table is reproduced as contained in BLM (2007).

A.6 REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

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ATTACHMENT A1:
**ANTICIPATED REFINERY MARKET RESPONSE
TO FUTURE OIL SHALE PRODUCTION**

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**ANTICIPATED REFINERY MARKET RESPONSE
TO FUTURE OIL SHALE PRODUCTION**

1 INTRODUCTION

Ultimately, crude shale oil's acceptance into the U.S. refinery market will be based on a number of factors. While some of these factors are well understood and can be used to make reliable forecasts, others are difficult to precisely define at this time. This brief overview of the manner in which the U.S. petroleum refining market may react to new crude oil sources from shale oil identifies some of the major factors that will influence decisions regarding construction or expansion of refineries. Among the factors that predominate in supporting refinery market adjustments are the following:

- The investment into and expansion of refining capacity are solely determined by the investor's long-term expectation of refining margins. Only those crude oil sources that can demonstrate long-term availability and consistent quality factors are likely to be considered as expansion or displacement candidates.
- New crude oil sources displace sources in existing markets on the basis of how well their quality parameters align with existing or expanding refining capability; the market will take proportionally longer to accept new sources with quality factors substantially different from those of existing or alternatively available sources.
- Indicators of potential new incremental markets include forecasted refining capacity expansion in existing facilities or in proposed new refineries. Currently, only a few small facilities are in the planning or permitting stages, and no large-scale integrated distillate fuel refineries have been publicly proposed.
- Incremental expansion at existing facilities is the expected way in which crude oil shale will be introduced into the refinery market in the short term, especially considering the time it has historically taken to plan, permit, design, and build new refineries (> 10 years).
- Identification of the most probable markets for the shale oil crude is dependent upon the phase of its growth. Early adopters could displace existing sources in geographically local markets with shale oil of comparable quality. Subsequent phases of oil shale industry development will require the development of logistical capacity and transport to larger markets to accommodate the higher production levels, with the Midwest and Gulf Coast

markets becoming available first, followed by the West and East Coast markets.

- Intuitively, domestic sources of crude shale oil are more desirable than foreign sources of crude oil simply because of their inherently more secure status. However, to retain their advantage, such domestic sources must also compare favorably with imported feedstocks with respect to overall product yield and other quality parameters (e.g., high-sulfur, high-acid content). Crude shale oil has great potential for replacing equivalent amounts of imported crude oil with comparable quality factors.
- Of the imported crude sources likely to be displaced by crude shale oil, the most likely are those currently being delivered to refiners in the Midwest and Gulf Coast, the two geographic areas composing the largest and most flexible markets for crude. Imported crude oil supplies most similar in quality to crude shale oil would be the first to be replaced since that replacement would require little to no change in refining capability.
- Pipelines do not drive refinery market investments; pipeline operators react to committed emerging markets and provide transportation linkage between the source and the refiner.¹

The U.S. refining market is not geographically equally distributed, and it has evolved into concentrations of refining capacity. The volume and types of crude that each of these refining concentrations consume have also evolved given their economic and logistical access to various sources of crude. In addition, the economics of processing crude oil that has particular characteristics (e.g., heavy crude oil) has driven the type of processing capability and subsequently investments. For example, the Gulf Coast, with easy waterborne access to traditionally cheaper foreign crude imports, has emerged with a large share of the U.S. refining capacity. The increased availability of heavy foreign crude at a price discount has spurred increased heavy crude processing capacity in this region. Subsequently, extensive logistical capacity to transport refined products to larger consumer markets, such as the Northeast, has evolved. In contrast, inland refining centers, such as the Rocky Mountains, have expanded only to serve their regional markets. The inland centers originally were configured to process primarily lighter domestic crude. Only relatively recently, with the growth of heavy Canadian crude oil imports, have they invested in increased refining capacity to process heavy crude.

The growth of total refining capacity has tended to result from the expansion of existing facilities rather than from the construction of totally new facilities. The lower risk to capital investment afforded by incremental expansion and economies of scale has supported this approach. While incremental expansion is the norm, it does occur in significant overall quantities and does have associated incremental environmental impacts.

¹ However, operators of existing pipelines may be reluctant to accept crude shale oil with high nitrogen content for fear of contamination of subsequent batches of conventional crude oils. Consequently, either crude shale oil upgrading must occur at the mine site, or a dedicated crude shale oil pipeline infrastructure must be created.

Refinery capacity growth and the location of this growth is determined by a complex mix of economics, acceptance of all environmental impacts, and in some situations, availability of basic resources, such as water and electricity, and logistical access. The same synergies of local markets for workers and equipment, logistical access, and markets for feedstock and product trading that created the existing concentrations of refining capacities have directed continued growth to these same areas.

This paper reviews some of these issues to identify the inherent drivers in the marketplace that could show the likely market placement of increased production of U.S. crude shale oil. The relatively recent entry of Canadian syncrude and bitumen into the U.S. refinery market provides a good example of how U.S. oil shale production might enter the refining market.² Volumetrically, the amount of Canadian syncrude and bitumen currently entering the U.S. market is of the same general order of magnitude as an estimate of anticipated commercial production levels for U.S. oil shale facilities (i.e., about 2 million bbl/day).³ The Canadian crude experience can help define logistical infrastructure changes, the economic factors that control inflow into existing refining centers, the probability of refinery expansions, and the possible crude sources that may be displaced. It is important to note, however, that recent trends in refining demand for Canadian crude are economically favoring the nonupgraded raw bitumen, which is sold at a substantial discount, thus providing the refiners with more margin potential. This ultraheavy bitumen is analogous to other foreign heavy crudes, which are in abundant supply in the marketplace and are also sold at a steep discount. The increased utilization of these ultraheavy crudes has required extensive investments in the “bottom-of-the-barrel processing” coker capacities. The shale oil and upgraded synthetic portions of Canadian crude have very little “bottoms” or residual; therefore, not only can they be processed in refineries without significant capital investment, they can serve as a complementary blending component with the ultraheavy crudes to balance the overall feedstock pool to the refinery. They must be produced, however, at an economically attractive price to compete with these steeply discounted heavy crudes

2 OVERVIEW OF THE CRITICAL PARAMETERS IN THE CRUDE OIL REFINERY PROCESS

Crude oil is a mixture of hydrocarbons formed from organic matter. It varies in chemical and physical composition, including differences in sulfur content, typically small amounts of nitrogen, acidity, density, etc. At the most fundamental level, the refining process involves actions in any of the following categories:

- Separation—Distillation,

² The organic fraction of Canadian tar sands is what is referred to here as bitumen. Syncrude is that which results from the mine site upgrading of bitumen. Both raw bitumen and syncrude are currently being delivered to U.S. markets.

³ To facilitate discussion of the potential effects of oil shale development, the BLM assumed a commercial production level of approximately 2 million bbl/day.

- Conversion—Changing the size and/or shape of molecules, and
- Treatment/blending—Making products to desired specifications.

The first step in the refining process is crude distillation. Crude distillation breaks a full barrel of crude into intermediate feedstocks through the application of heat and pressure. A small portion of the yield of a distillation tower can be recovered and marketed as a finished product. Most distillate fractions, however, must be further processed in downstream conversion units into blend components, petrochemical feedstocks, and finished petroleum products. The distillation process is merely a separation process, while other downstream conversion processes actually involve chemical reactions that modify the molecular structures of the hydrocarbon distillate fractions to produce products with desirable physical and chemical qualities. Figure 1 shows a generic refinery flow. The initial crude oil composition dictates the relative proportions of initial distillate fractions.

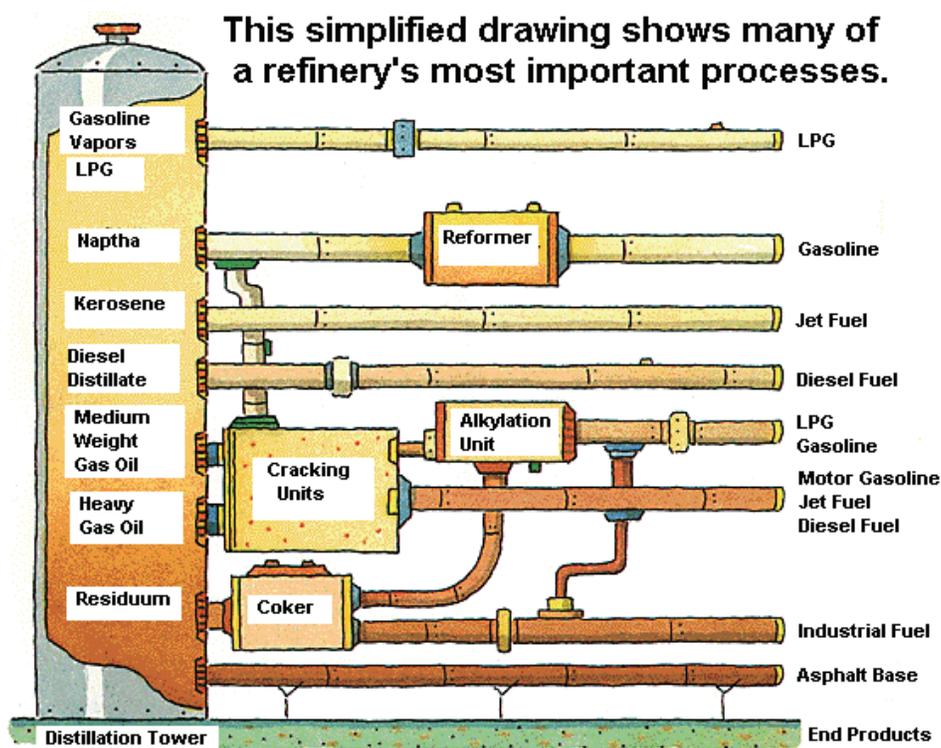


FIGURE 1 Generic Refinery Configuration (Source: EIA 2006a) (LPG stands for liquefied petroleum gas.)^a

^a Not all conventional crude oils are appropriate starting material for production of asphalt; however, they can instead efficiently produce heavy-weight fuel oils, such as bunker fuels used in ocean-going vessels or #6 fuel oil used in industrial boilers.

Crude oil sources are typically classified by density. By industry convention, density is expressed as American Petroleum Institute (API) gravity: light (API >34), medium (API 26–24), or heavy (API < 24).⁴ Density, in turn, is reflective of fundamental differences in underlying chemical compositions. The lighter the crude source, the greater the relative percentage of small- to moderate-sized organic molecules with high degrees of saturation, making it more amenable to conversion into high-value products such as gasoline and other low-boiling fuels and products. Heavier crude will have greater relative concentrations of heavier components with higher degrees of unsaturation. Such compositions lend themselves more readily to conversion into heavier distillate products such as various grades of fuel oils, lubricating oils, asphalts, and similar products, as shown in Figure 2.

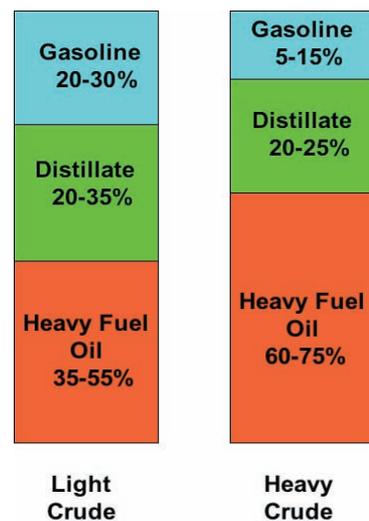


FIGURE 2 Comparison of Conversion Products Based on Crude Composition (Adapted from Day 2005)

While it is chemically possible to convert any quality crude to a wide range of final products, to convert heavier crude feedstock into high-value products requires substantial amounts of energy and results in reduced yields. Consequently, crude oil density (and, more specifically, chemical composition) dictates the refining pathway and the relative proportion of distillate products in most instances. This is the case for any crude source, including crude shale oil. The maximization of a refinery's total production value is derived by optimizing each component of the refinery, such as impurity removal, and each type of processing capacity. Consequently, for existing refineries considering replacement of an existing feedstock, the desirability of a crude shale oil source as a replacement will be as dependent on the shale oil's quality and how well it aligns with the preferred refining pathway and intended final products for that refinery as it is on outright market price. On the other hand, when the pending decision is to create a new refinery or to expand an existing refinery to produce different products, long-term availability, supply logistics, and cost become more influential but still do not displace the long-term refining margin returns as the primary basis for the decision.

As the above discussion suggests, many factors ultimately determine the extent of crude shale oil's penetration into the existing petroleum refinery market; however, the crude shale oil's overall quality (chemical composition as well as critical physical properties) would be the primary factor on which refineries base their decisions to pursue shale oil feedstocks. Unfortunately, the quality of crude shale oil produced at commercial scale is currently one of the areas of greatest uncertainty. Empirical evidence suggests that, together with the intrinsic variability in the composition of the parent oil shale, the quality of recovered shale oil ultimately offered to the refinery market will be highly dependent on the extraction and retorting technologies selected and the nature and extent of mine site upgrading. That being said, there is

⁴ API gravity is an arbitrary scale for expressing the specific gravity or density of liquid petroleum products. Devised by the API and the National Bureau of Standards, API gravity is expressed as degrees API. API gravities are the inverse of specific gravity. Thus, heavier viscous petroleum liquids have the lower API values.

very little experience related to commercial-scale shale oil development.⁵ The newest in situ retorting technologies undergoing research and development (R&D) hold the promise of recovered shale oil of exceptional quality. (For example, Shell Oil anticipates that its in situ heating/retorting technology may yield crude shale oil of roughly 30% fractions each of raw naphtha, jet fuel, and diesel fuel and 10% residual. Shell further believes that relatively minor adjustments to field conditions could allow a change in composition of recovered product in response to extant refinery market conditions.) At this point in time, however, neither legacy technologies nor cutting edge technologies have amassed sufficient evidence on which to safely predict the quality factors that would result from their implementation at commercial scales. Long-term reliability of quality factors is absolutely critical to refinery acceptance, more so than the absolute values of those quality factors.

3 MARKET RESPONSES TO FEEDSTOCK VALUE PARAMETERS

Because heavier crude sources produce fewer high-value products, or produce higher-value products only with additional processing costs, markets compensate by trading heavier crude at a price discount relative to lighter crude. Heavier crude stocks are further discounted to offset the higher processing costs of using cokers to convert this low-value residual into higher-value gasoline and distillate components rather than less valuable heating fuels and asphalts, lubricating oils, and road oils. Transportation fuels (e.g., gasoline and distillates) are the highest demanded products. Without upgrading capacity, there would be an excess of fuel oils and asphalts, and refiners would process lighter crudes rather than the economically desirable heavier crude. Figure 3 shows the refining margins associated with processing light and heavy crudes. The green line highlighted at the top represents the difference between processing the benchmark light (e.g., West Texas Intermediate) and heavy (Mexican Maya) crudes. As can be seen on the left axis, this reached a peak of an approximately \$40 per barrel advantage of heavy crude over light crude this year. The Canadian crudes referenced in this paper are in the heavy category. While the expected composition of U.S. crude shale oil is not known precisely, it will probably be more comparable to the light crude in value than to the heavier crude stocks now available on the market. Mine site upgrading could further improve this equivalency.

The second element critical to the desirability of crude oil supplies is sulfur content. New specifications on gasoline and diesel are increasingly requiring lower and lower sulfur content. Sellers of high-sulfur crudes have to discount them enough to account for the required sulfur extraction process in the refinery. From a sulfur content perspective, some U.S. shale oil products could be more attractive than conventional domestic crudes and Canadian imports. Green River oil shale sulfur content ranges from 0.46 to 1.1% (by weight), approximately 30% organic sulfur compounds, with sulfur content increasing as the richness of oil shale deposits increase.

⁵ However, crude shale oil upgrading efforts associated with the Unocal operation at Parachute, Colorado, successfully demonstrated that crude shale oil could be converted to a syncrude whose properties, including substantially reduced concentrations of nitrogen and sulfur-bearing contaminants, made it acceptable for receipt at refineries.

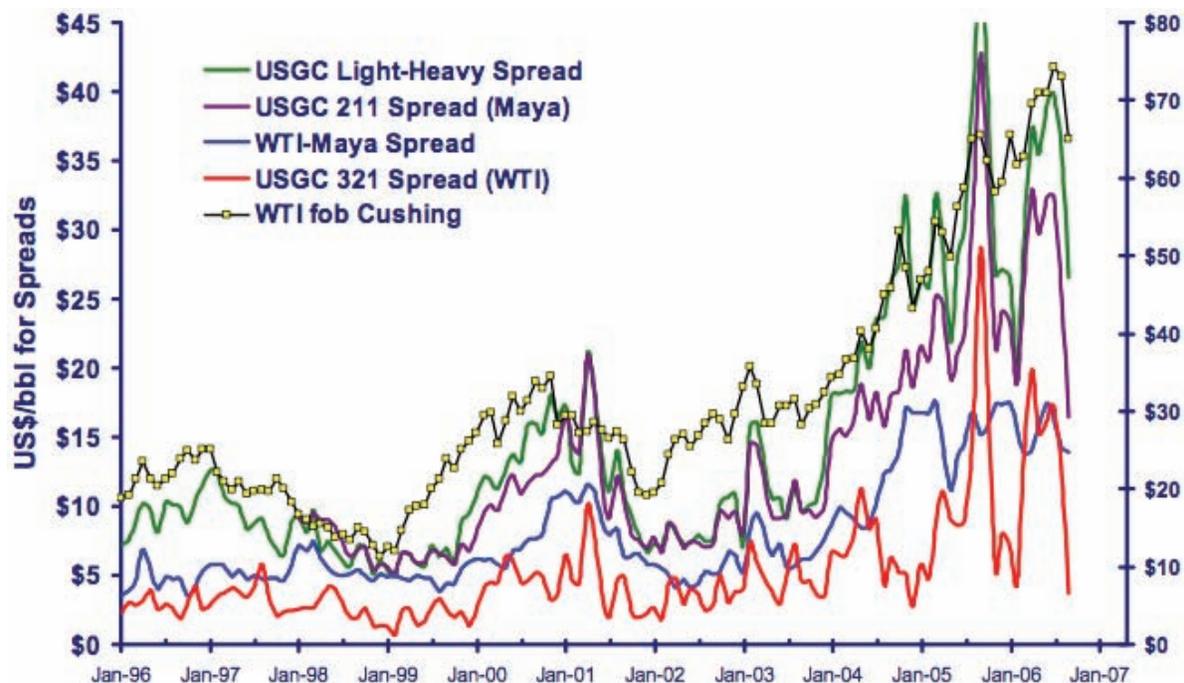


FIGURE 3 Heavy vs. Light Crude Refining Margins (Source: Arnold 2006)

Because of the high investment capital required to modify a refinery to process heavy crudes, refiners electing to do this have typically signed 7- to 10-year crude supply agreements. These long-term crude supply agreements shrink the near-term market available for heavy crude displacement by new crude shale oil supplies.

Given the uncertainty of quality factors that can be expected for commercially developed shale oil, it is difficult for refinery operators to determine the relative attractiveness of future crude shale oil sources against currently available sources. Frequently, operational adjustments and sometimes equipment investments have to be made to adapt to a significant change in a crude oil source. This could be related to process upgrading, impurity removal, or accommodation of other metallurgy, heating, cooling, or pumping capacities. Even without major structural changes, the normal unit variations created with introductions of new sources typically result in a refinery repeatedly testing small volumes of a new feedstock over a period of time to better understand the impacts on operations. Until long-term quality factors are established for crude shale oil, it is reasonable to expect a lag between initial commercialization of oil shale facilities and the development of refineries to accept it. Such an initial lag may be shortened to some extent by interim decisions on the part of refineries to accept crude shale oils of lesser quality with the intent of blending them with existing stocks to produce averaged quality factors in the blend that can still be managed economically in existing refining units with little to no modifications.

Shale oil facility operators also have opportunities to influence their potential place in the refinery market and to reduce the hesitancy of refineries to accept their product by the degree of upgrading they perform on their products. Since demand for low-sulfur distillate fuels is

currently high and expected to increase (especially given the additional influence of recent lowering of sulfur limits in diesel fuel by the U.S. Environmental Protection Agency [EPA]), upgrading to align shale oil more directly with the high-quality conventional crude sources that now support that refinery market segment is the most likely objective. Thus, if shale oil developers pursue this option, upgrading actions at the mine site would be designed to remove sulfur and nitrogen and increase hydrogen-to-carbon ratios with reactions such as hydrocracking to improve the quality of initially recovered crude shale oil and make it more competitive with higher-quality conventional crude oil feedstocks.

However, given that shale oil production sites will be located in generally arid or semiarid regions with limited sources of power, fuel, and water for processing, extensive treatment and upgrading of crude shale oil could be limited in the early years of industry development by the availability and costs of required resources and may, therefore, occur only to the extent necessary for safe and economical pipeline transport to an off-site refinery. Should this be the case, early market penetration of shale oil would more likely be the result of the pursuit of blending options rather than displacement of high-value conventional crude feedstocks.

4 REFINERY UTILIZATION FACTORS

The refining process is a continuous liquid process. During normal operation, a refinery operates 24 hours per day, 7 days per week; however, maintenance on various units is periodically required. Individual (or groups of) units are typically shut down every 1 to 5 years, depending upon the unit type, and for 1 to 3 weeks for a unit “turnaround.” A turnaround involves a major maintenance overhaul of the unit, including replacing catalysts, performing upgrades, and replacing worn-out components. In addition, feedstock variation or unit upsets can cause feed preheating, pumping, overhead cooling capacity, sulfur recovery, etc., to become constraints, further lowering the overall utilization of the plant. Therefore, the overall utilization of the refinery is reduced by the amount of time the units are down. Thus, most data sources account for the realities of refinery operation by representing refinery capacity in two ways: barrels per stream day (BSD) and barrels per calendar day (BCD):

BSD represents the absolute maximum rate at which a unit can operate during any single day. This rate is a function of unit design and the capacity of supporting systems but cannot be sustained for extended periods of time.

BCD represents the maximum rate of production a unit can sustain over the course of a year given maintenance downtime and operating limits due to varying feed qualities. As such, the BCD value is the only reliable representation of a refinery’s long-term production capacity.

The differences between BSD and BCD are unique for each refinery and reflect the types and ages of individual refining units and their respective repair and maintenance demands. The quality of the incoming feedstock also affects the difference between BSD and BCD capacities, since the amounts and types of impurities that must be removed during processing can greatly affect maintenance and overhaul schedules of individual units. Such factors explain the reported

utilization rates for refineries being typically less than 100%. U.S. refineries run as much as is operationally feasible over the long term. However, because of these maintenance turnarounds, operational upsets, and unforeseen breakdowns, their overall utilization average nationwide is about 90 to 93%. Utilization rates for refineries in the closest vicinity to Green River oil shale deposits currently range from 91 to 95%. This, however, is still the maximum operating rate that can be reliably anticipated.

The difference between BCD and BSD, or between either rate and 100%, does not reflect spare capacity that can be utilized when desired to accommodate a new feedstock source, however. Unless otherwise specified, refinery capacities referenced in the remainder of this analysis mean BCD.

5 CURRENT STATE OF PETROLEUM REFINING IN THE UNITED STATES

The 149 operable refineries in the United States range in size from very small and specialized individual processing units with a capacity of 1,500 BCD, to large integrated refineries with capacities exceeding 550,000 BCD.

For the purpose of data collection, refineries are arranged in geographic regions known as Petroleum Administration for Defense Districts (PADDs). This system of categorization dates back to World War II and was devised to administer the distribution of petroleum products. PADDs also reflect the natural boundaries and flows of petroleum feedstocks and refined products. Figure 4 shows the geographic boundaries of the PADDs.⁶

Figure 5 shows the histograms of refinery sizes by PADD. PADD 4—Rockies has a disproportionate number of small refineries in comparison with the other PADDs, and these small refineries only serve regionally local markets and are configured to produce a limited array of products. The PADD 4 refineries originally were almost exclusively supplied with domestically produced crude from fields within the PADD. Now, additional pipeline investments have been made, bringing Canadian crude into the region. In most cases, additional upgrading capacity was added at the refineries to process the heavier Canadian crude. A relatively high sulfur concentration characterizes the remaining domestic crude production in the region. Key producing states in PADD 4, such as Wyoming and Montana, currently have an excess capacity of domestic crude production. In addition to pipeline logistical constraints, the consistent expanding price differential between light crude over heavy crude has kept this domestic production of light crude noncompetitive outside of this region. This was the first market with logistical connections with Canada and was the first market penetrated by Canada, although in relatively small volumes compared with Canada's current production.

⁶ The U.S. Department of Energy (DOE) Energy Administration Agency (EIA) collects and provides reporting on energy data. Considerable information can easily be obtained at the EIA Web site: <http://www.eia.doe.gov/>. Much of this data reporting is aggregated on a regional basis, and the data are organized by PADDs.

Petroleum Administration for Defense Districts

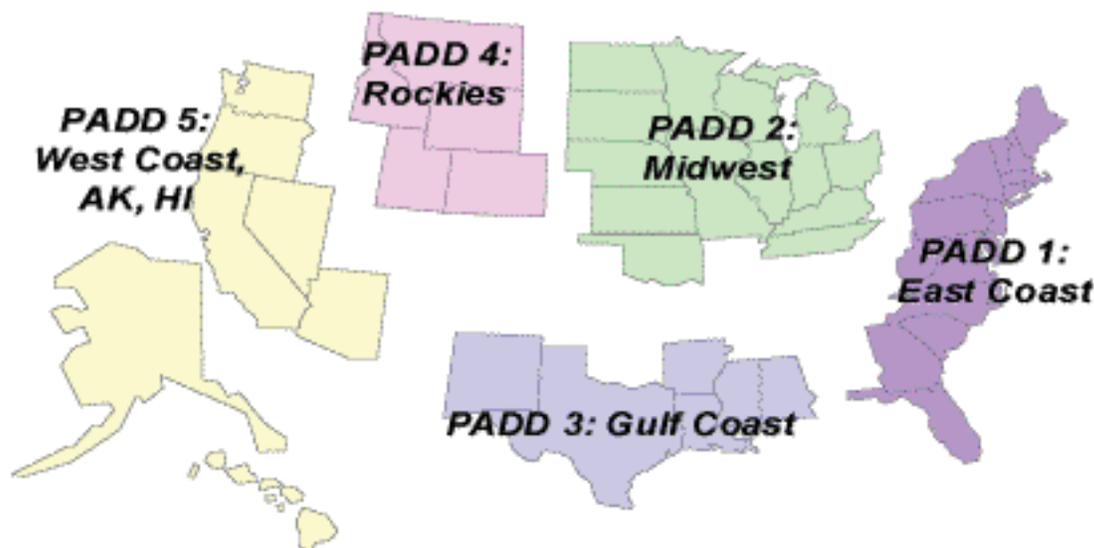


FIGURE 4 Petroleum Administration for Defense Districts Map (Source: EIA 2006b)

Figure 5 shows the refinery production capacity and its variation arranged by PADD or regional basis. This is an important view for broader and longer range analysis. Figure 6 shows individual refining capacities by state for the production region of interest. This view defines the current maximum potential volume penetration for crude shale oil in PADD 4. Such market penetration could occur without the significant transportation infrastructure expansion that would be required before shale oil market penetration into any other PADD could take place. Thus, penetration into these “local” refinery markets is the most likely scenario in the early years of commercial oil shale production.

As shown in Figure 7, U.S. refining capacity increased a total of 3.6 million bbl/day between 1985 and 2004, and refinery utilization rates have been stable at near maximum achievable levels. The last refinery built in the United States was in Garyville, Louisiana, in 1976. Current conservative estimates for construction of a new refinery are about \$2.4 billion for a 150,000-bbl/day capacity (\$16,000/bbl/day of processing capacity). The most expensive sale of an existing refinery asset was Valero’s recent purchase of Premcor, which sold for approximately \$10,000/bbl/day of processing capacity. With existing assets selling for well under construction costs, there is little incentive to develop a new grass roots facility. Nevertheless, between 1985 and 2004, U.S. refineries increased their total capacity to refine crude oil by 7.8%, from 15.7 million BCD in 1986 to 16.9 million BCD day in 2004, but only maintained a consumption rate of 15.7 million BCD, reflecting a utilization rate of operating capacity equivalent to 93%. This increase in operating capacity is equivalent to adding several mid-size refineries, but it occurred, instead, as a result of expansions of production capacities at existing refining facilities to take advantage of economies of scale (Slaughter 2005). Much of the current capital investment is going to environmentally related processing capability. Over the last 10 years, U.S. refiners

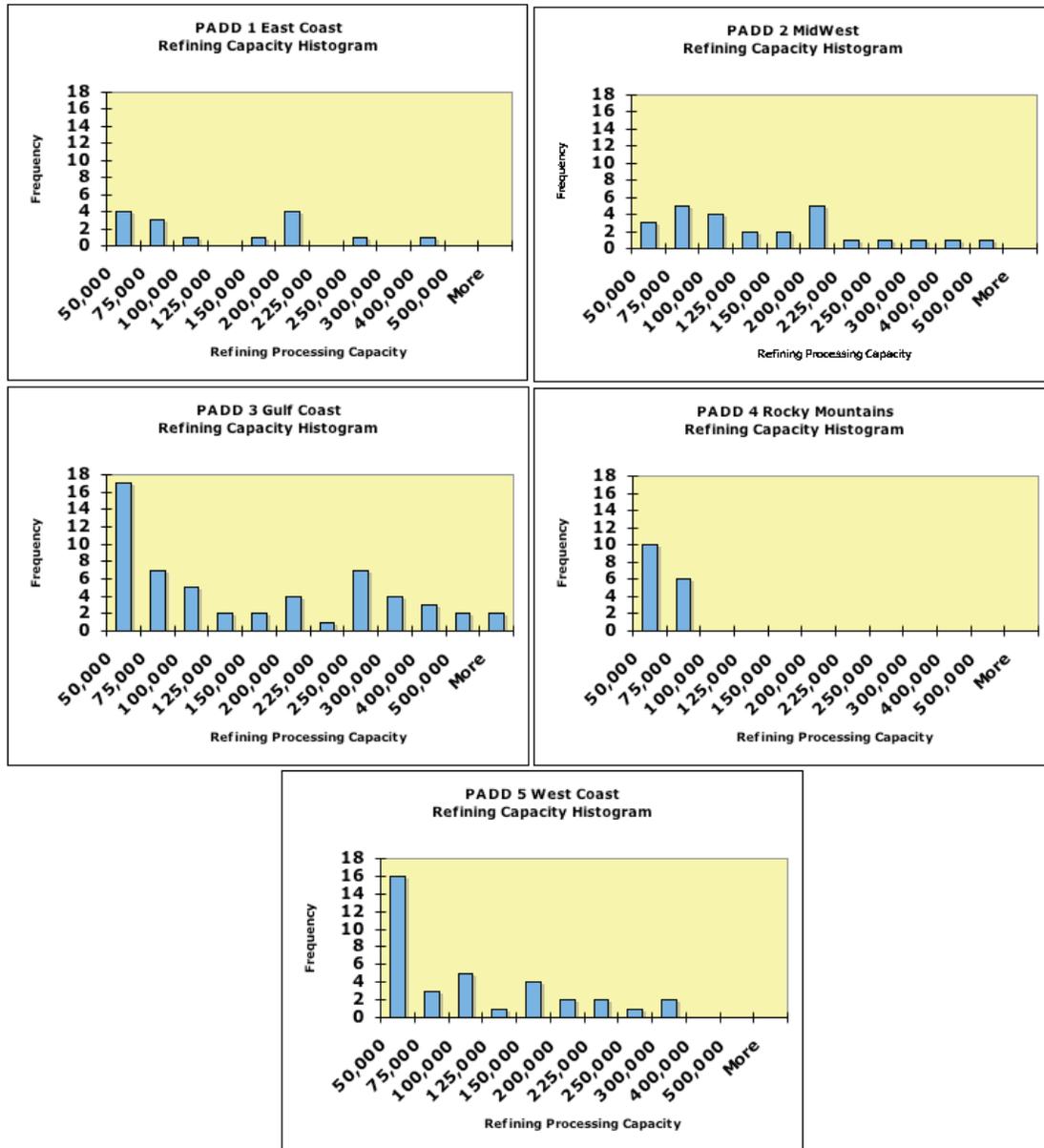


FIGURE 5 Distribution of Refining Capacities (Source: EIA 2006c)

have spent approximately \$47 billion (Slaughter 2005) to reduce sulfur levels in transportation fuels and to comply with 14 new environmental regulations that come into place this decade (Wall Street Journal 2004). Of the 60 refinery expansion projects identified by the *Oil and Gas Journal*, 38 are environmentally related, 14 are for conversion units, and only 8 are related to expanding or retrofitting crude distillation capacity. Approximately 300,000 bbl of crude distillation capacity are committed to refinery expansion through 2010. However, despite the overall increase in production capacity that would result, utilization rates for refineries overall

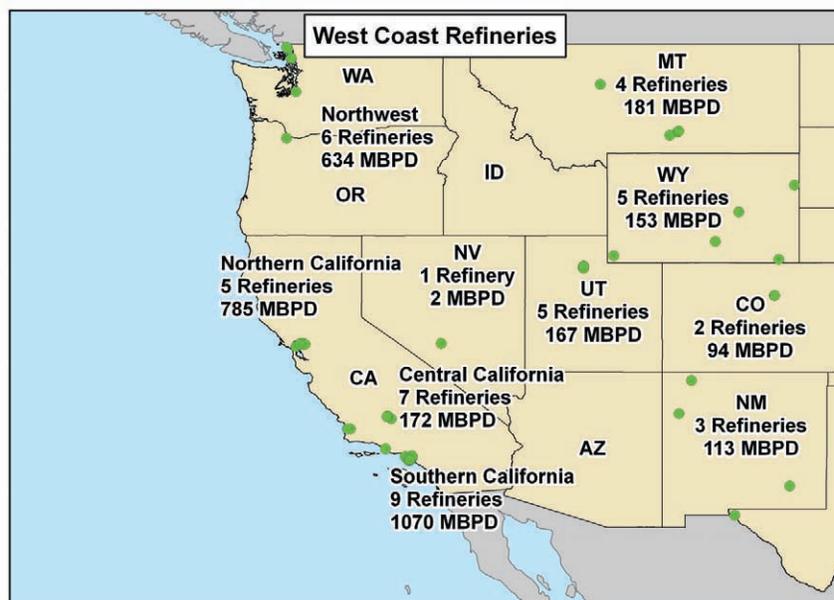


FIGURE 6 Western States Refining Capacity (Source: EIA 2006c)

are not expected to change substantially.⁷ However, refinery expansion is a continuous process of capital project evaluation, so it does not represent a true forecast for refinery capacity. Because of the industry's tendency to expand existing assets, initial new market growth for shale crude oil is most likely to be at existing areas of refining concentration.

U.S. demand for refined products has grown steadily, and growth is expected to continue into the foreseeable future. Similarly, increased refining capacity has followed a parallel growth path to meet the rising demand. Current margins and announced refinery projects suggest that refinery growth will continue into the foreseeable future. The distinction of whether or not such growth occurs at a new location or whether it comes through expansion of existing facilities is not critical in evaluating the foreseeable potential of crude shale oil. If the market drives the crude shale oil to be delivered to the Gulf Coast, expansion of existing large refinery facilities to take advantage of associated economies of scale would be the probable response. If a new facility was constructed to take specific advantage of crude shale oil economics and logistical availability, it would not necessarily be located within the immediate vicinity of the crude shale oil sources. Ultimately, increase in refining capacity, whether through expansions or new facilities, will occur to the extent necessary to serve the ultimate markets for the end products. Whether the crude shale oil is transported to existing refining centers for processing or whether a new facility is constructed to refine the crude closer to the point of production is a function of economics and market balance and is not an inherent constraint on the viability of crude shale oil production. In either scenario, there is a positive realization of the crude shale oil market and an associated environmental impact wherever refinery expansion occurs.

⁷ Since these expansions would involve new processing units utilizing state-of-the-art technologies, some minor improvements of utilization rates may result, but such increases are likely to be insignificant when averaged over the entire U.S. refining capacity.

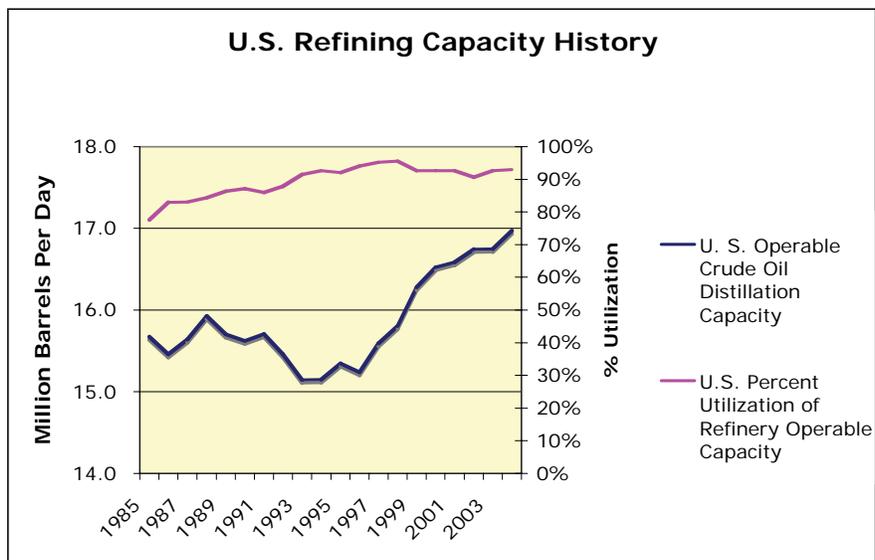


FIGURE 7 U.S. Refining Capacity (Source: EIA 2006d)

Refinery expansion occurs to profitably meet growing demand. Feedstock selection is a secondary process of optimizing refinery economics. Given the complexity of the dynamics of meeting increasing refinery demand and/or displacing existing crude supplies, attribution of refinery expansion to the introduction of crude shale oil is difficult. A further complication arises with the realization that over a period of as long as 20 years, production rates of some current feedstock sources may fall dramatically, therefore “freeing up” refining capacity without the need for refinery expansions.

6 CURRENT CRUDE SOURCES

Any new crude source has to find a market in either expanded refinery production or by competitively displacing other crude supplies in the market (including through the adoption of feedstock blending strategies by refineries). This section describes the existing sources of crude feedstock that are supplying U.S. refineries.

In 2005, the United States processed 15.8 million bbl of crude per day. Of this, 2.4 million bbl/day comes from domestic production, 2.1 million bbl/day is imported from Canada, and 11.3 million bbl/day comes from other international sources. Crude is produced domestically in 28 states and in state and federal offshore waters on the West Coast and the Gulf of Mexico. Figure 8 shows domestic production by state.

The most likely market for new domestic crude sources is the displacement of comparable foreign crude. Figure 9 shows the percent of crude processed in each state that is imported as well as the volume that percentage represents. States in the extreme North and some in the Midwest are processing Canadian imports, which are less likely to be displaced because of

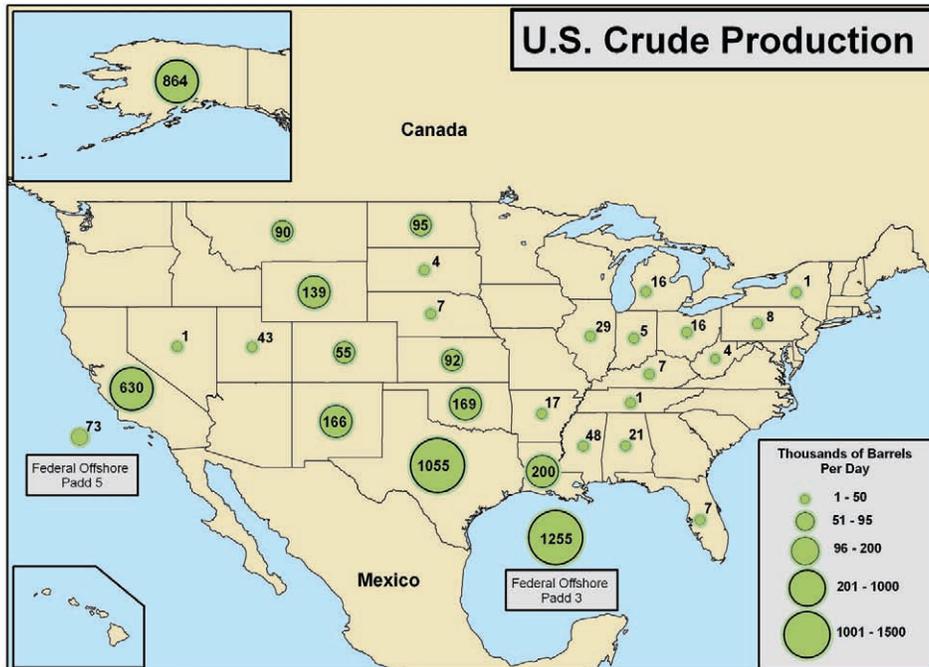


FIGURE 8 Domestic Crude Production (Source: EIA 2006e)

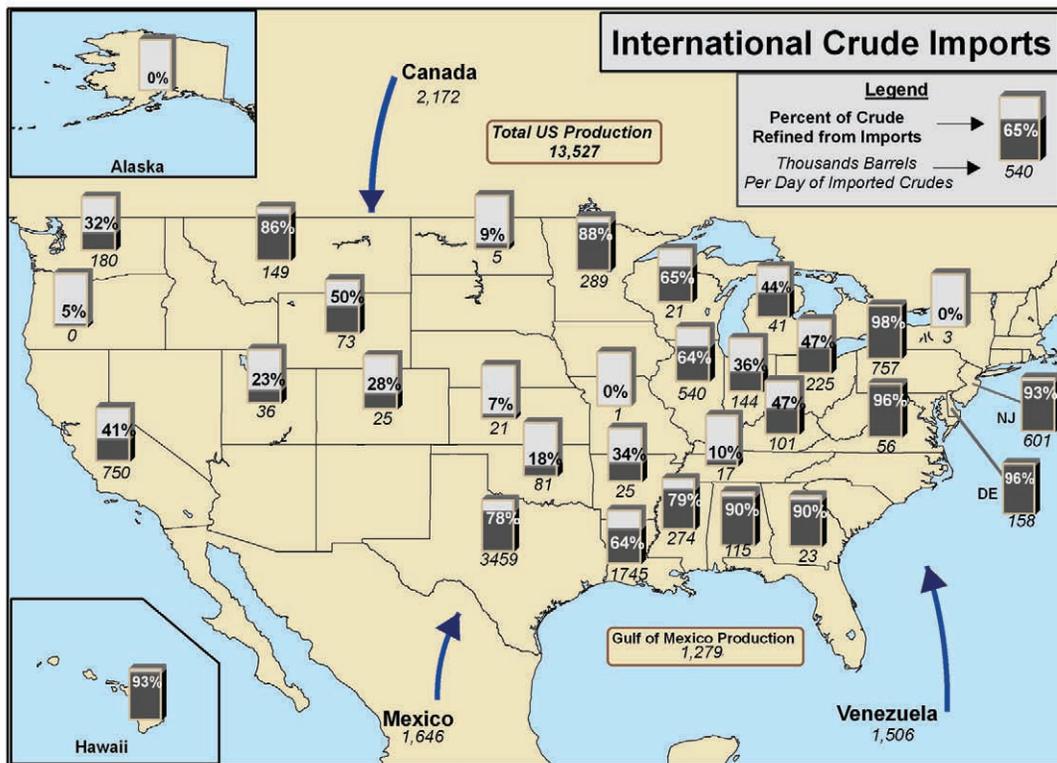


FIGURE 9 International Crude Imports (Source: EIA 2007)

the capital investment in upgrading already made or committed to by refineries to process these heavy crude supplies. The Canadian producers are developing crude pipelines to the Gulf Coast and are looking to the Gulf Coast PADD as their next incremental market. Any substantial shale oil production would likely follow this same market pattern. Summary information describing each of the PADDs is provided below:

- PADD 1—East Coast has primarily waterborne crude receipts. It is net short of refining capacity and is a large importer of refined products from within the United States and internationally. It is the least likely market for crude shale oil. It receives refined products through the Colonial and Plantation pipelines and refined imports from the Caribbean and Europe.
- PADD 2—Midwest is geographically constrained from the primarily waterborne receipts in the Gulf Coast and offshore domestic Gulf Coast production. Its access via crude pipelines from the Gulf adds additional expense. Therefore, it was a natural secondary market for Canadian penetration. It is a very diverse PADD with a wide range of refinery sizes and configurations and serves a wide range of product specifications, including heavy integration of ethanol (for use in gasoline blending). PADD 2 has been the largest regional recipient of Canadian crudes entering the market. This is because of its large total refining capacity and its relatively closer proximity to the Canadian sources than other refining center markets. Its proximity to Canada and associated crude pipelines and the relatively higher cost to ship foreign crudes from the Gulf Coast to Midwest refineries makes PADD 2 a naturally attractive and economic recipient of Canadian crudes. Without some unexpected extensive logistical expansion of crude shale oil to other markets, such as the West Coast, these same factors will make PADD 2 the most likely recipient of any substantial volumes of shale oil.
- PADD 3—Gulf Coast is the heart of the U.S. refining concentration. It not only contains the most diverse refinery sizes and configurations, it is also the most integrated, with exchanges of secondary feedstocks with refineries and petrochemical plants. The first step in refining is distillation, which breaks crude into components such as naphtha, distillates, etc. These are considered secondary feedstocks in that they feed conversion process units downstream of the initial crude distillation. Secondary feedstocks are routinely sold to other refineries or to petrochemical plants. If a secondary market for this is readily available, such as in the Gulf Coast, then a refiner has to be less concerned with balancing the composition of the crude with the individual unit capacities. The refiner can sell or purchase additional intermediates to make up for crude mismatch. The extensive number of petrochemical plants within the immediate vicinity of PADD 3 refineries further expands market flexibility for secondary feedstocks. This makes a much more competitive crude environment and lowers the premium on crude qualities, since there is more freedom to correct poor-quality feeds. The Gulf Coast also was the original recipient of foreign heavy crude and, therefore, has extensive

- upgrading and sulfur extraction processing capacity for these supplies. Having access to a wide variety of world crude supplies, these refiners present a more competitive landscape for producers of crude oil and also establish a lower barrier to market entry for any feedstock that has differentiating economics. Pipeline reversals and new pipeline construction are underway to transport Canadian crudes to PADD 3. The large market is certainly an alternative for larger volumes of shale oil but, again, is the most competitive on price.
- PADD 4—Rockies is the region in which crude shale oil would be produced. Its refineries are relatively smaller than those in other PADDs. Its crude market is primarily domestic light sour production and imported Canadian crude. Canadian crude imports have increased substantially. It was one of the first markets to be exploited by Canada until further logistical capacity could be built to the Midwest and then later connections could be made with other pipelines to the Gulf Coast. The markets for the refined products are also very localized, with the exception of the product pipeline from Salt Lake City, Utah, to eastern Washington and Oregon. Environmental considerations, such as water availability, could be a larger issue to refinery expansion in PADD 4 than in other PADDs. PADD 4 refiners are implementing improved wastewater recovery and water conservation projects in existing refineries in this region. PADD 4 would be the most likely early adopter, and refineries would be available with little pipeline capacity increase, but, collectively, refineries in this PADD are very limited in the total volume of new feedstock that they can accept. Full realization of the shale oil potential will require significant displacement of current crude sources to PADD 4 refineries or crude shale oil sales in other PADDs.
 - PADD 5—West Coast is a complex but isolated market. The product requirements of the California Air Resources Board (CARB) are very challenging for refiners. Access to European and Gulf Coast products is constrained logistically by the transit time and ship availability to transit the Panama Canal (including the size limitation imposed on ships by the Canal). Even within the PADD, interchanges of supply and distribution are complex. Many of the San Francisco area refiners cannot produce CARB-approved gasoline and, therefore, export the entirety of their gasoline production to Washington and Oregon. Washington refiners can make CARB-approved gasolines and, therefore, produce for this higher-profit market segment and supply gasoline to southern California, which is net short of all products. Washington refiners produce some high-sulfur distillates, which exceed U.S. specifications, and these distillates are exported to both Latin America and South America. PADD 5 processes approximately two-thirds of domestic crude, including Alaska North Slope crude. Both California and Alaskan domestic crude sources are expected to decline within the 20-year time frame for this shale oil forecast horizon. The Southern California refiners, representing more than 1 million bbl/day of processing capacity, are particularly short of crude, and any domestic declines will only increase their

disadvantage. While there are currently no crude pipelines to carry shale oil crude from the Rocky Mountain area to the West Coast, PADD 5 represents a sufficiently attractive market for consideration in that pipeline infrastructure investments are likely over the long term.

7 CANADIAN CRUDE PRODUCTION

Canada is one of the largest crude exporters into the United States and is becoming of greater strategic importance given the increasing uncertainties associated with other foreign crude sources. It is enlightening to review the history of Canadian syncrude oil's entry into the U.S. refining market since this has been a relatively recent injection of a significant volume of crude feedstock into the U.S. market and may be representative of the pathway that U.S.-produced crude shale oil may follow. The source for the information presented in this section is *Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006–2015*, published in 2006 by the Alberta Energy and Utilities Board (EUB 2006).

The majority of Canadian syncrude is produced in Alberta Province, which is geographically closest to and competes with Western U.S. crude production. Most syncrude is now produced either by mining tar sands or by various in situ techniques using wells to extract crude bitumen. The product is generally classified as "heavy crude." Raw bitumen production has been increasing in recent years and accounts for more than 60% of Alberta's 1995 total crude feedstock production. A large portion of Alberta's bitumen production is upgraded to syncrude. Upgraders chemically add hydrogen to bitumen, subtract carbon from it, or both. In upgrading processes, the sulfur contained in bitumen may be removed. Bitumen crude must be diluted with some lighter viscosity product (called a diluent) in order to be transported in pipelines. Use of heated and insulated pipelines can decrease the amount of diluent required; however, such techniques are not feasible for transport over long distances.

Canada has accomplished a dramatic increase in overall crude production, and it is forecasted to continue increasing at a large rate. Figure 10 shows the historical growth and forecast of Canadian crude oil by source. At the rate of anticipated production growth displayed in Figure 10, Canadian syncrude could represent a substantial percentage of total crude volume consumed by U.S. refineries within the near future. For example, by 2015, a forecasted Canadian syncrude production volume of approximately 4.5 million bbl/day could represent as much as 28% of the U.S. refinery industry's crude consumption.⁸

Canadian exports to the United States have grown approximately 15% since 2000. By 2015, 3.5 million bbl/day are expected to be exported to the United States, which would be an

⁸ The EIA forecasts that, by 2015, the total volume of crude actually consumed by all U.S. refineries will be 16.3 million bbl/day. For clarification against refinery capacities discussed earlier, assuming continuing refinery utilization rates of 93%, this volume infers 17.5 million BSD refinery distillation capacity, which can be reasonably expected to come from incremental expansions of existing facilities. For EIA crude volume consumption forecasts, see EIA (2006f).

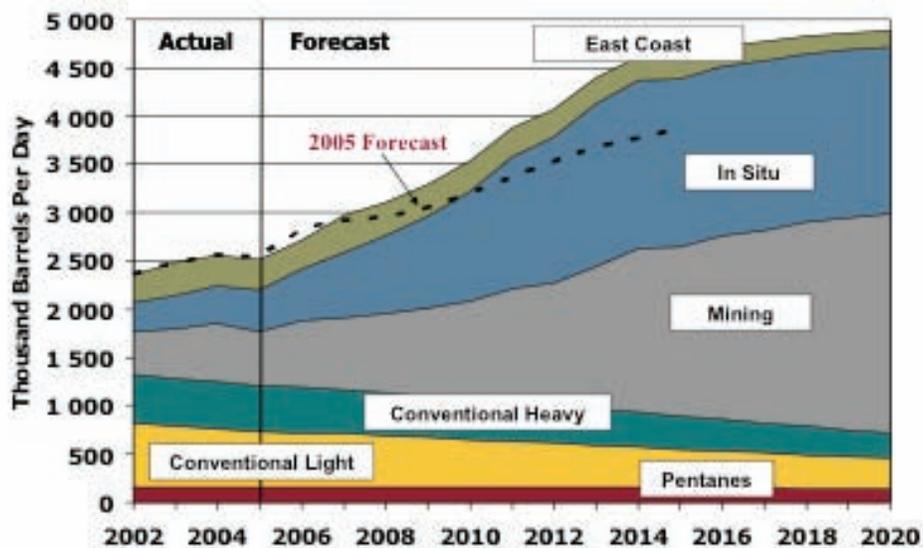


FIGURE 10 Canadian Crude Supply Forecast (Source: CAPP 2005)

increase of 1.5 million bbl/day over current levels. Figure 11 shows the disposition of the Canadian exports to the United States by state.

In the United States, PADD 4—Rockies, although small in overall refining capacity, and PADD 2—Midwest have been the traditional markets for Canadian crude. However, several announced pipeline projects constructing new pipelines and reversing the direction of flows in existing pipelines are currently planned or under construction. The most significant is the planned construction of the Keystone pipeline and the reversals of the Spearhead and ExxonMobil line targeting significant new pathways to the PADD 3—Gulf Coast market. Significant increases in U.S. crude shale oil production in PADD 4 also would likely target similar markets of existing refinery capacity. As noted earlier, there are similar drivers between U.S. crude shale oil and Canadian crude because of geographical location and associated transportation capacities and costs. However, they do differ in chemical composition. Expected higher production costs as well as heavy subsidization of Canadian synthetic crude oil by the Alberta government suggest that the U.S. crude shale oil will not be offered at the lower cost that enables higher refining margins for the Canadian heavy crude. However, because commercially produced crude shale oil can be expected to be lighter than Canadian synthetic crude oil, its acceptance into refineries will not require incremental investment in heavy crude processing capacity.

Figure 12 shows the refining locations and the associated volumes of gasoline production in thousands of metric tons per year. This shows the concentration of refining assets in the Gulf Coast and West Coast markets and the lack of them in the Rocky Mountain source region.

To accomplish logistical movements of existing and planned import volumes, a series of pipeline construction projects, reversals of existing pipelines, and pipeline capacity expansions are underway. Figure 13 shows the current and projected Canadian and U.S. pipeline projects.

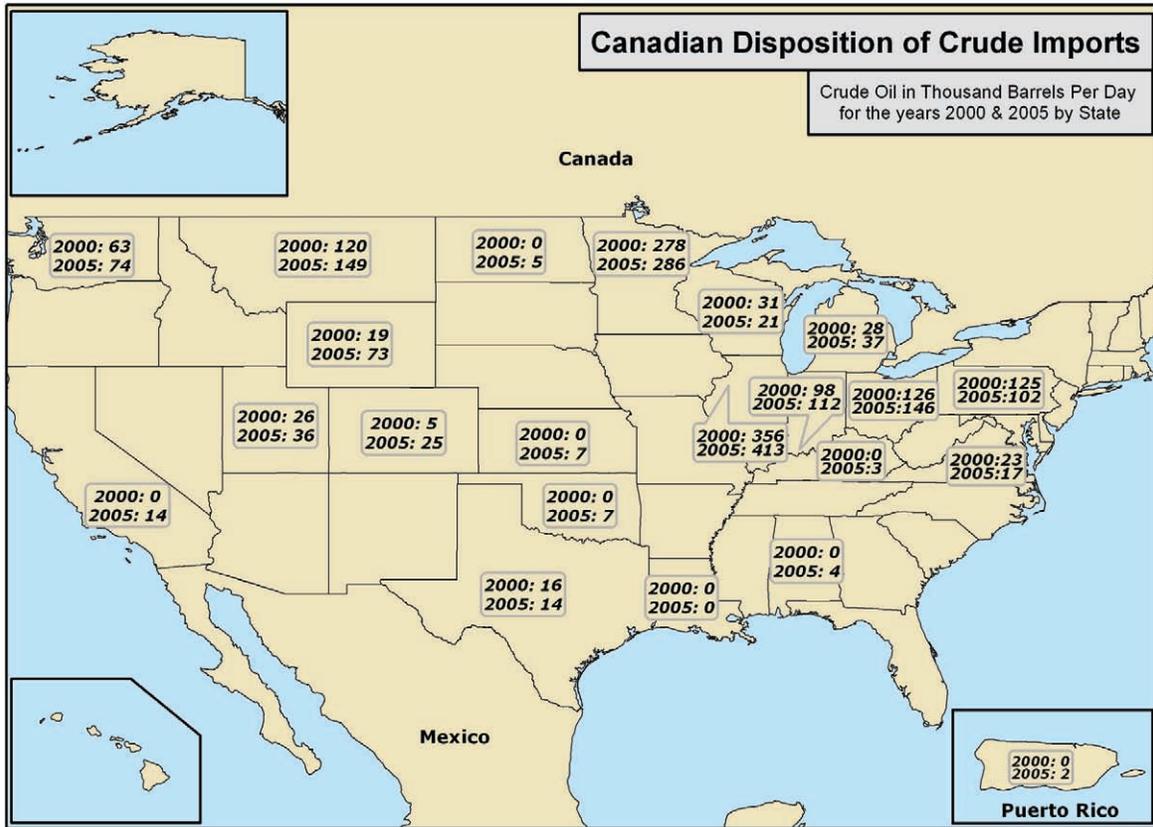


FIGURE 11 Canadian Crude Oil Disposition (Source: EIA 2007)

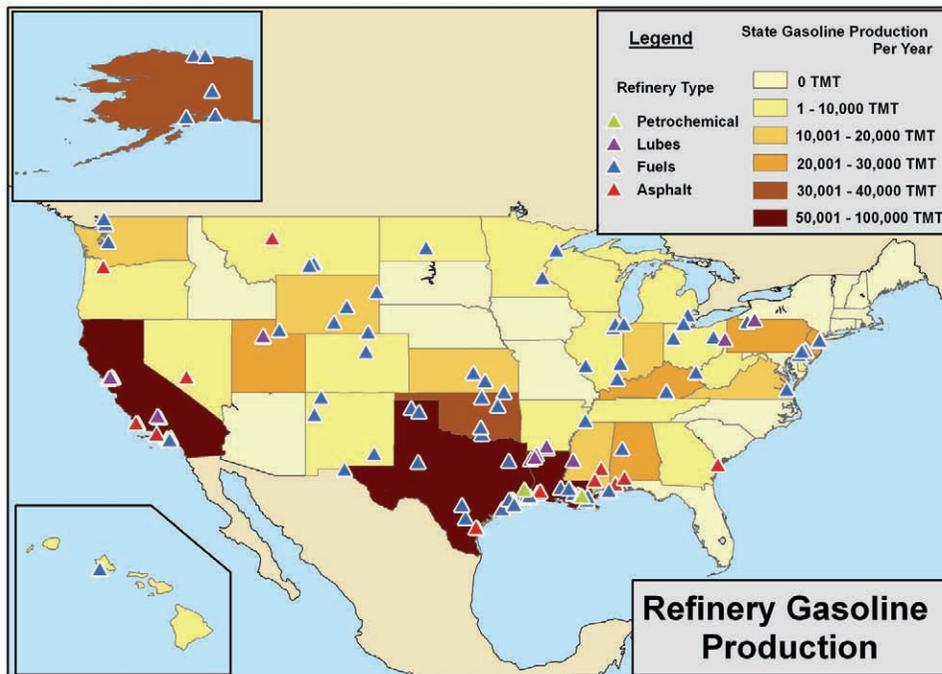


FIGURE 12 Refinery Locations and Gasoline Production (Source: EIA 2006c)

shale oil. By this point in time, the quality of commercially available shale oil should have stabilized so that the true determining factor would be a market-driven valuation of the crude composition and qualities versus its transportation and processing economics. Either PADD 2 or PADD 3 could absorb up to 2 million bbl/day additional shale oil with little refinery configuration restructuring required if the market determines it is economically advantageous to do so.

In the long term (probably 10+ years), other markets such as PADD 5—West Coast could also become viable. The potential decreases in California and Alaskan North Slope crude production and/or increased insecurity in foreign crude availability could provide the motivation to construct high-capacity pipelines to supply that market.

Uncertainty as to the exact quality of commercially produced shale oil prevents a precise determination of the feedstock market segment in which it would be most competitive. Current in situ technologies under evaluation show the promise of partial upgrading of crude oil prior to recovery from the oil shale formation as well as the conversion of sulfur and nitrogen-bearing compounds to hydrogen sulfide and ammonia compounds, respectively, either of which can be easily removed from the product stream. Although this hypothesis remains unproven at commercial scales, if it is realized, the resulting crude shale oil could be both lightweight and low in sulfur content (relative to many current conventional feedstocks), which could give it a distinct advantage over both the high-sulfur conventional domestic crude production and the Canadian synthetic crude oil. This may influence both the rate and extent of market penetration for shale oil.

Refinery expansion and operations will also be influenced by environmental factors, which contribute to the overall market picture. Issues such as air quality (attainment status for each of the primary ambient air quality criteria pollutants as well as source-specific emission limitations) and water availability could constrain or preempt significant expansions of existing refineries or the construction of new refineries in certain geographic areas. It is intuitive that refinery growth occurring in the immediate vicinity of a crude oil source would minimize transportation costs; however, other factors, such as ambient air quality and water availability, could be key constraining factors in refinery expansion that could overwhelm any concerns for transportation costs. In addition to the high water requirement of typical refineries of 1 to 3 bbl of water per barrel of processed crude, the degree of impurities present in crude shale oil could create increased wastewater and waste disposal issues. In the final economic models that are typically employed, transportation costs are nominal and have very little influence over the ultimate decision regarding the location of the refinery relative to the crude oil source. Of a more critical influence is the existing pipeline capacity that links the market areas under consideration. However, as has been suggested in the introduction, pipeline operators will expand their capacities and build pipelines linking new locations once markets are reliably established.

Environmental controls aimed not at refineries but at some distillate fuel products may also influence the overall market. New low-sulfur fuel requirements will put high-sulfur feedstocks at a disadvantage or will require expensive expanded sulfur control capabilities at refineries currently receiving such feedstocks. The intrinsically lower sulfur content of crude shale oil compared to some conventional crude feedstocks, as well as the ability of crude

producers to further reduce sulfur content through in situ retorting techniques and/or mine site upgrading, could greatly increase shale oil's attractiveness to refineries producing such distillate fuels.

9 OTHER POSSIBLE MARKET DRIVERS

Declines in supply from existing major exporters (e.g., Venezuela and Mexico), domestic sources (North Slope of Alaska), and geopolitical events could create an increasing demand for domestic crude production in the future. Venezuela and Mexico have been primary sources of crude oil, with each providing approximately 1.5 to 1.7 million bbl/day into the United States, but concern for these sources is growing. Venezuela has been unable to return to the level of production in 2001, and the government has become increasingly antagonistic to U.S. interests. Also, there is growing industry concern over the decline of Mexican production because of the lack of investment, which could dramatically impact production levels in the next few years. With two major Western Hemisphere producers facing uncertain futures and continuing concerns over the Middle East and Africa, the medium-term potential for increased demand for domestic crude production could improve the market viability for production and processing of crude shale oil.

Alaska North Slope production has been in decline and is currently supplying approximately half of its historic peak. Although there are considerable logistical challenges to moving crude to the West Coast, future declines in supply from Alaska could create increased demands on the West Coast that could improve what is currently considered a nonviable market for moving feedstock from the Rocky Mountain region to the West Coast.

While nearby crude sources are likely declining, world demand for crude oil is expected to increase by 47% by 2030. China and India are expected to account for more than 40% of this increase (EIA 2006f). These forecasts of increasing demand and diminishing resources are creating an international competition, which is being acted on now. China began the process of constructing a Strategic Petroleum Reserve in 2004 and is increasing its relations with oil producers, such as Angola, Central Asia, Indonesia, the Middle East (including Iran), Russia, Sudan, and Venezuela (Office of the Secretary of Defense 2005). Further international energy risk could provide additional incentive for utilization of domestic resources.

Legislation could also play a role in driving the advancement of shale oil. The Energy Policy Act of 2005 extends the Title VII, National Oil Heat Research Alliance Act of 2000, providing for research for use of distillates as home heating oil. Heating oil equipment is found to "operate at efficiencies among the highest of any space heating energy source." Further support of this could drive additional demand for the types of distillates that can be produced from upgraded shale oil. The same act also directs the Secretary of Energy to select sites necessary to procure the fully authorized Strategic Petroleum Reserve (SPR) storage volumes. Although additional segregation would be required from the current SPR storage, shale oil could be upgraded to meet additional SPR storage acquisition or even displace existing barrels of conventional oil. The need to extend the physical storage capacity affords an opportunity to

evaluate alternative locations, from the existing Gulf Coast-centric storage to support production in the Rocky Mountain region, or storage and consumption in Southern California or the upper Midwest. In addition, Section 369 of the Act directs the Secretary of Defense to procure fuel derived from coal, shale oil, and tar sands. This could also stimulate a demand, especially in the western United States. While the precise nature of future actions implementing these statutory directives is unknown at this time, impacts on the oil shale industry are easily anticipated.

10 CONCLUSIONS

The unknowns regarding the quality and availability of crude shale oil, the extent to which it may be upgraded at the site of production, and the time frames for expansions of pipeline capacity for movements outside the immediate production area introduce considerable uncertainty with respect to the timing and specifics of refinery market development. As a result, it is difficult to predict with certainty how the refinery market will respond to oil shale development on public lands over the next 20 years (2007 to 2027). It is likely that during the first 10 years of the study period (2007 to 2017), there will be no commercial oil shale production; activities during this period will be focused on R&D and demonstration only. Commercial-scale production may start around 2017 at some project sites and reach a level of about 1 million bbl/day from those sites within a few years. Additional production from other project sites could start in a similar time frame, and a production rate of approximately 2 million bbl/day could be reached around the end of the study period.

The information presented in this paper defines the factors that will likely impact the incorporation of shale oil into the market. In addition, information from the relatively recent introduction of Canadian synthetic crude can be used to define a possible path for crude shale oil market infusion. To make any projections about the refinery market response to oil shale production, it is necessary to make certain assumptions. It is assumed that the U.S. refinery market will respond in a fashion consistent with past behavior. It is further assumed that both the Canadian crude and other foreign crude will continue at their current levels of availability. This analysis of potential markets for shale oil does not depend upon any reduction in available global supply typically referred to as the peak oil argument. The expected build-out of shale oil production will enter at the beginning of the peak oil argument. Any international decline in crude oil production will only create greater demand for alternative crude production sources. An exception to the assumption that all existing crude supplies remain relatively stable is the Alaskan North Slope crude supply, for which, as noted, current projections forecast a significantly reduced production in the 10-year time frame. In the Alaska projection, the Alaska National Wildlife Refuge is not assumed to be in production.

Because of the many uncertainties that still exist, it is probable that market development will proceed in different directions during different growth phases of the crude shale oil market. Initially, the market is likely to respond to new crude shale oil production through displacements of similar or complementary quality crude supplies from the refinery stream rather than expansions of refinery capacity. Such displacements, however, will be tempered by conditions in

the market, including the relative price of crude oil of similar quality and existing crude oil supply contracts (as in the case of existing contracts for heavy Canadian crude oil).

On the basis of historic patterns of expansion in refining capacity, refinery expansions to incorporate new crude shale oil supplies will occur incrementally, largely within areas of existing concentrated refining capacity, and only after refiners have identified a long-term profit margin for expanded facilities. The availability of new supplies alone is not sufficient to drive new refining capacity (as seen in the current oversupply of light crude in Wyoming). Only long-term profit potential will provide that incentive.

The scenario described below reflects the suppositions and constraints discussed in this paper. There is no historic precedent for production increases of this magnitude in such a short period of time; therefore, this scenario may not be accurate. It does not represent the only pathway by which shale oil refining markets will develop but can nevertheless be justified on a number of critical levels.

Development will likely occur in three phases:

1. Early adoption and geographically local market penetration within PADD 4,
2. Market expansion outside of PADD 4 with increased logistical capability (for both oil shale production facilities and transportation infrastructure), and
3. High-volume production and multimarket penetration of a mature shale oil industry.

Successful market penetration is a balance of crude shale oil availability, logistical availability (i.e., pipeline transportation), and market demand. Each phase of market maturity for shale oil will confront constraints in one or more of these areas. The relative significance of these constraints will shift during the various phases of maturity.

Phase 1, early adoption and local market penetration, will likely occur during the first 5 years of commercial development. If approximately 1,000,000 bbl/day of oil shale is produced in Colorado during this time, the abundance of shale oil supply will be placed into a refinery market that already is experiencing excess domestic production. Transportation capacity will be the limiting factor during this phase. Until reliable product definition and consistent quality of the crude shale oil are established, refineries will have a slow adoption rate and are more likely to only replace existing sources of crude of comparable quality. While it is unlikely that new refineries will be constructed during this period in response to this new production, the crude transport connections and overall refinery capacities within the PADD 4—Rocky Mountain region will need to be improved in order for these refineries to be early adopters. This could translate into the construction of new pipelines in the PADD 4 region. Demand in PADD 4 is not expected to increase dramatically during this time, but refineries could potentially reconfigure their processes or create new blends of crude stocks to better align their feeds with desired products. The potential qualities of crude shale oil could be similar to domestic light crudes and if market conditions allow, could compete with an already oversupplied local domestic crude

market in the immediate vicinity. Alternatively, Phase 1 could be very short-lived, or skipped entirely, and Phase 2 conditions could prevail.

Phase 2, market expansion beyond PADD 4, is likely to involve expansion of the transportation network, allowing distribution of crude shale oil outside of PADD 4. At the point in time that PADD 4 reaches a saturation point, thus presenting a growth-limiting factor, Phase 2 expansions beyond PADD 4 will need to occur. This could occur starting around 2022 (or sooner) and extend until 2027 or beyond. To accomplish this, expansion of pipeline capacities to multiple markets outside of PADD 4 will be required. As addressed above, the most likely markets are the Midwest and Gulf Coast, although some potential growth could occur in the local markets. Because of the limited forecasted refinery expansion over this time period, new market penetration will require displacement of alternative sources of crude oil. The overall cost of production, the final qualities of the crude shale oil, and the availability of out-of-region transport will determine the economics and, subsequently, its economic viability. During this period, it is also unlikely that new refineries will be constructed in any of the PADDs; more likely, the transportation network will expand and there could be some expansions at existing refineries.

Phase 3 represents multimarket penetration and the maturation of the shale oil industry where the market is at equilibrium and crude shale oil availability is the limiting factor rather than transportation or refinery capacity. This phase assumes large volumes of crude shale oil would be produced (approximately 2 million bbl/day). By this time, it is realistic to expect that PADD 5—West Coast refineries that have been utilizing California and Alaskan North Slope crude will be searching for alternative sources of supply, which may bring these refineries into the shale oil market equation. The market viability of these levels of production is probably dependent upon integration with multiple regional markets and assumes ongoing economic viability versus alternative sources. Even in this long-range projection, neither demand or refining capacity in the PADD 4 local markets is expected to increase to a level that could utilize the expected shale oil production; thus, development of markets in other regions will be necessary to sustain the industry or allow it to reach its full projected production capacity.

The long-term view for the potential for the oil shale industry beyond 2027, with an expected production capacity of 2.1 million bbl/day, could be realistic. On the basis of recent experience with the development and penetration of U.S. markets by Canadian syncrude, however, the early and mid-phase development scenarios are aggressive, especially given some of the unknowns regarding the final reliable quality of crude shale oil produced at commercial scale and the extended time lines required for market acceptance and development of both transportation and refining infrastructures. Assuming that the chemical characteristics of the crude shale oil product are desirable (and assuming no revolutionary development of refining technology that would make feedstocks of marginal quality more desirable), market manipulation, including possible subsidization or facilitation of development of logistical infrastructure (e.g., designated pipeline corridors), could speed up market acceptance and make the overall scenario more likely.

11 REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed.

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