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

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APPENDIX A:**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 *Draft Programmatic Environmental Impact (PEIS) and Possible Land Use Plan Amendments for Allocation of Oil Shale and Tar Sands Resources on Lands Administered by the Bureau of Land Management in Colorado, Utah, and Wyoming* 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.

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.

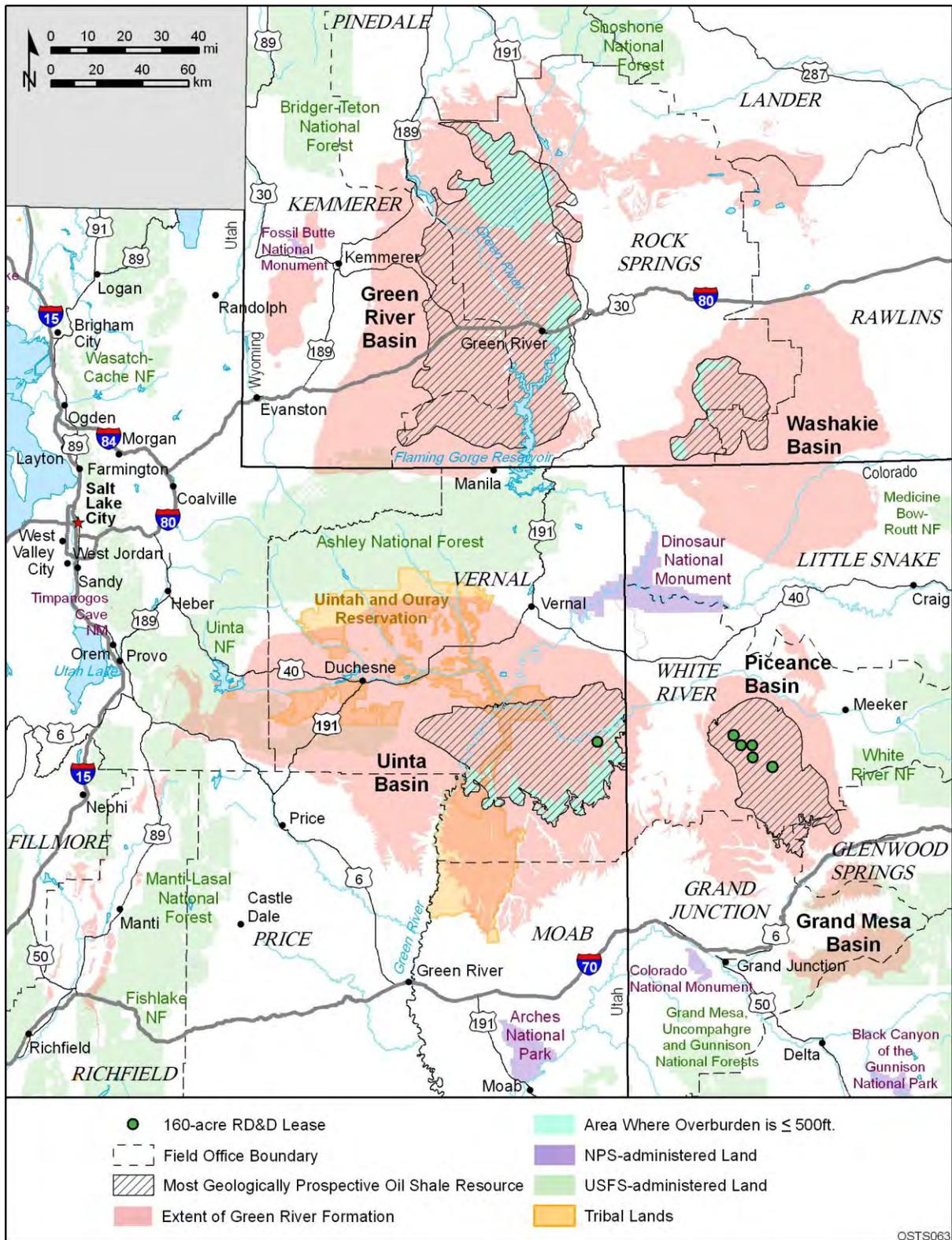
1 Numerous deposits of oil shale are found in the United States. The most prospective shale
2 deposits are contained within sedimentary deposits of the lacustrine Green River Formation of
3 Eocene age. These deposits exist in the greater Green River Basin (including Fossil Basin and
4 Washakie Basin) in southwestern Wyoming and northwestern Colorado, the Piceance Basin in
5 northwestern Colorado, and the Uinta Basin in northeastern Utah.² Because of the deposits' size
6 and grade, most investigations have focused on the oil shale deposits in these basins. As
7 discussed in Section 1.2 of the main text of the PEIS, in defining the scope of analysis for the
8 PEIS, the BLM identified the most geologically prospective areas for oil shale development on
9 the basis of the grade and thickness of the deposits. For the purposes of this PEIS, the most
10 geologically prospective oil shale resources in Colorado and Utah are defined as those deposits
11 that are expected to yield 25 gal of shale oil per ton of rock (gal/ton) and are 25 ft thick or
12 greater. In Wyoming, where the oil shale resource is not of as high a quality as it is in Colorado
13 and Utah, the most geologically prospective oil shale resources are those deposits that are
14 expected to yield 15 gal/ton or more shale oil and are 15 ft thick or greater. Figure A-1 shows the
15 Green River Formation basins, which were mapped on the basis of the extent of the Green River
16 Formation, and the most geologically prospective oil shale resources within those basins.³
17

18 In addition to limiting the scope of analyses to the most geologically prospective
19 resources, the BLM has determined that, for the purposes of establishing a commercial leasing
20 program for oil shale development on public lands, oil shale resources that are covered by more
21 than 500 ft of overburden would not be available for application for leasing using surface mining
22 technologies under the scope of this PEIS. This limitation is based on the assumption that 500 ft
23 is about the maximum amount of overburden where surface mining can occur economically,
24 using today's technologies. Figure A-1 shows the areas within the three-state region where
25 surface mining would be considered under the commercial leasing program on the basis of the
26 overburden thickness.⁴ Although some of the oil shale resources outcrop in Colorado and have
27 overburden thicknesses of less than 500 ft, the distribution of these areas presents a relatively
28

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).



1

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

1 narrow band of lands within which it would be difficult to assemble a logical mining unit;
2 therefore, surface mining projects in Colorado are not evaluated in this PEIS.
3
4

5 **A.1.1 Depositional Environment** 6

7 The Green River Formation was originally deposited in two basins that were later warped
8 into four large structural basins and then elevated several thousand feet above mean sea level
9 (MSL). The major streams and their tributaries traversing the region have eroded much of the
10 sediments from these exhumed basins. The stream erosion has exposed the oil shale on cliffs
11 and ledges in many places. Gentle folds and minor faults deform the deposits locally, but the
12 sedimentary rocks of the oil shale areas as a whole are remarkably undisturbed structurally.
13 Exceptions occur in the areas where the strata are steeply tilted on the flanks of the Uinta Mountains
14 in Utah and Wyoming and along the Grand Hogback in Colorado.
15

16 Lacustrine sediments of the Green River Formation that have become oil shale were
17 deposited in two large lakes that occupied 24,000 mi² in several sedimentary structural basins in
18 Colorado, Wyoming, and Utah during early through middle Eocene time (40 to 65 million years
19 ago). These basins are separated by the Uinta Mountain uplift and its eastward extension, the
20 Axial Basin anticline. The Green River lake system was in existence for more than
21 10 million years during a time of a warm-temperate to subtropical climate. The two large lakes
22 initially were freshwater but became quite saline with time.
23

24 Fluctuations in the amount of inflowing stream waters caused large changes in the areal
25 extent of the lakes as evidenced by widespread intertonguing of marly (clay and carbonate-rich)
26 lacustrine strata with beds of land-derived sandstone and siltstone. During arid times, the lakes
27 contracted in size and the lake waters became increasingly saline and alkaline. The lake-water
28 content of soluble sodium carbonates and chloride increased, while the less soluble calcium,
29 magnesium, and iron carbonates were precipitated with organic-rich sediments.
30

31 During the driest periods, the lake water reached salinities sufficient to precipitate the
32 sodium minerals nahcolite, halite, and trona. The water filling the pore spaces in the sediments
33 was also sufficiently saline to precipitate disseminated crystals of nahcolite, halite, and
34 dawsonite along with a host of other carbonate and silicate minerals (Milton 1977). In Wyoming
35 (Lake Gosiute), trona was precipitated. In Colorado (Lake Uinta), the minerals halite, nahcolite,
36 and dawsonite were precipitated. Why the two lakes precipitated different mineral salts is
37 unknown, but the resulting deposits of trona, nahcolite, and dawsonite constitute an immense
38 potential mineral supply.
39

40 The warm, alkaline waters of the Eocene Green River lakes provided excellent conditions
41 for the abundant growth of blue-green algae (cyanobacteria) that is thought to be the major
42 precursor of the organic matter in the oil shale. During times of freshening waters, the lakes
43 hosted a variety of fishes, rays, bivalves, gastropods, ostracods, and other aquatic fauna. Areas
44 peripheral to the lakes supported a large and varied assemblage of land plants, insects,
45 amphibians, turtles, lizards, snakes, crocodiles, birds, and numerous mammals (McKenna 1960;

1 MacGinitie 1969; Grande 1984). These areas where saline minerals are intermixed with oil shale
2 are referred to in this document as “multimineral zones.”
3
4

5 **A.1.2 Piceance Basin, Colorado** 6

7 The Piceance Basin is located mainly in the Colorado Plateau physiographic province.
8 The overall basin is more than 100 mi long and 60 mi wide, with an area more than 7,000 mi².
9 The Piceance Basin is simultaneously a structural, depositional, and drainage basin. The
10 structural basin is downwarped and surrounded by uplifts resulting from the Laramide Orogeny.
11 This tectonic activity created a depositional basin that filled with sediments from the surrounding
12 uplands, mainly during the Tertiary period. The basin has a northern province and a southern
13 province (Topper et al. 2003) separated approximately by the Colorado River and I-70. Oil shale
14 is present in both provinces.
15

16 Within the Piceance Basin, the upper bedrock stratigraphy consists of a series of basin-fill
17 sediments from the Tertiary period (Topper et al. 2003). The uppermost unit is the Uinta
18 Formation, which consists of up to 1,400 ft of Eocene-age sandstone, siltstone, and marlstone.
19 Below the Uinta Formation is the Eocene Green River Formation, which can be up to 5,000 ft
20 thick and includes four members: the Parachute Creek (keragenous dolomitic marlstone and
21 shale), the Anvil Points (shale, sandstone, and marlstone), the Garden Gulch (claystone, siltstone,
22 clay-rich oil shale, and marlstone), and the Douglas Creek (siltstone, shale, and sandstone). The
23 Eocene-Paleocene Wasatch Formation underlies the Green River Formation and is
24 approximately 6,900 ft thick near the town of Rifle, Colorado. Exposed Wasatch rocks include
25 clays and shales with some interbedded sandstone and are found in the lowest elevations between
26 the base of the cliffs and the major streams (the Colorado River, Government Creek, and
27 Parachute Creek). The Wasatch Formation is a significant oil and natural gas-producing unit in
28 the region. Below the Wasatch are the Cretaceous Mesaverde Group (sandstone and shale), the
29 Cretaceous Mancos Shale, and older sedimentary formations atop Precambrian rock. The
30 Mesaverde Group is the major oil- and gas-producing formation in the Piceance Basin.
31

32 The main oil shale members of interest in the Piceance Basin are the Parachute Creek and
33 Garden Gulch Members. The grade of oil shale varies with location and depth, but the Parachute
34 Creek Member has the richest material and includes the Mahogany Zone.
35

36 Elsewhere in the region, the Grand Hogback exposes Paleozoic and Mesozoic
37 sedimentary bedrock units that dip steeply to the west and southwest. Tertiary basalt flows cover
38 much of the higher-elevation areas south of the Colorado River (i.e., Battlement Mesa) and the
39 White River Plateau to the northeast. Quaternary alluvium occurs as a broad belt along the lower
40 reaches of Parachute, Rifle, and Government Creeks and along the Colorado River
41 (Widmann 2002). Quaternary alluvium of varying thickness is present in the significant
42 drainages of the basin.
43

44 Although the oil shale deposits in Colorado cover the smallest geographical area, they are
45 the richest, thickest, and best-known deposits. In addition, natural gas production is prolific from
46 formations located stratigraphically below the oil shale, with 4 of the top 35 natural gas fields in

1 the United States located in the southern Piceance Basin.
 2 Substantial quantities of saline minerals (halite, dawsonite, and
 3 nahcolite) are intermixed or intermingled with oil shale in certain
 4 zones in the northern half of the basin. Three layers of nahcolite
 5 are present near the base of this saline zone, and two halite-
 6 bearing strata exist in the upper part of the zone. The dawsonite
 7 and other saline minerals are finely disseminated in and
 8 associated with beds of oil shale, which are up to 700 ft thick
 9 near the center of the basin. Dyni (1974) estimated the total
 10 nahcolite resource at 29 billion tons. Beard et al. (1974)
 11 estimated nearly the same amount of nahcolite and 17 billion
 12 tons of dawsonite. Both minerals have value for soda ash and
 13 aluminum, respectively. Dawsonite has potential value for its
 14 alumina content and most likely would be recovered as a by-
 15 product of an oil shale operation. One company is presently
 16 solution mining about several hundred thousand tons/yr of
 17 nahcolite in the northern part of the Piceance Basin at depths of
 18 about 1,970 ft (Day 1998). The BLM has identified an area in the
 19 Piceance Basin, referred to as the Multiminerals Zone, where
 20 development of nahcolite, dawsonite, or oil shale cannot result in
 21 destruction of another resource.

22
 23 About 80% of the potential oil shale resources of the
 24 Green River Formation, or about 1.2 trillion bbl of oil equivalent,
 25 is found in west-central Colorado's Piceance Basin. Of the total
 26 potential resource, about 480 billion bbl are contained in deposits
 27 averaging at least 25 gal/ton. The higher-grade shale sections
 28 range from 10 ft to more than 2,000 ft in thickness and may be
 29 covered with overburden ranging up to 1,600 ft thick.

30
 31
 32 **A.1.3 Uinta Basin, Utah**

33
 34 In Utah, oil shale deposits are found in the Parachute
 35 Creek Member of the Green River Formation, which
 36 intertongues with but generally occurs above the Douglas Creek
 37 Member. As many as eight oil shale zones have been identified
 38 in the Parachute Creek Member; the richest oil shale is found in
 39 the Mahogany Zone, which contains up to 100 ft or more of rock
 40 that averages 15 gal/ton. Figure A-2 is a generalized stratigraphic
 41 section of the rich and lean oil shale zones of the Parachute
 42 Creek Member of the Green River Formation in the Uinta Basin,
 43 Utah. The thickness of the different zones shown in the
 44 stratigraphic section is not constant but varies across the basin.
 45 No single comprehensive and modern study of the oil shale
 46 resources of the entire Uinta Basin has been carried out. An early

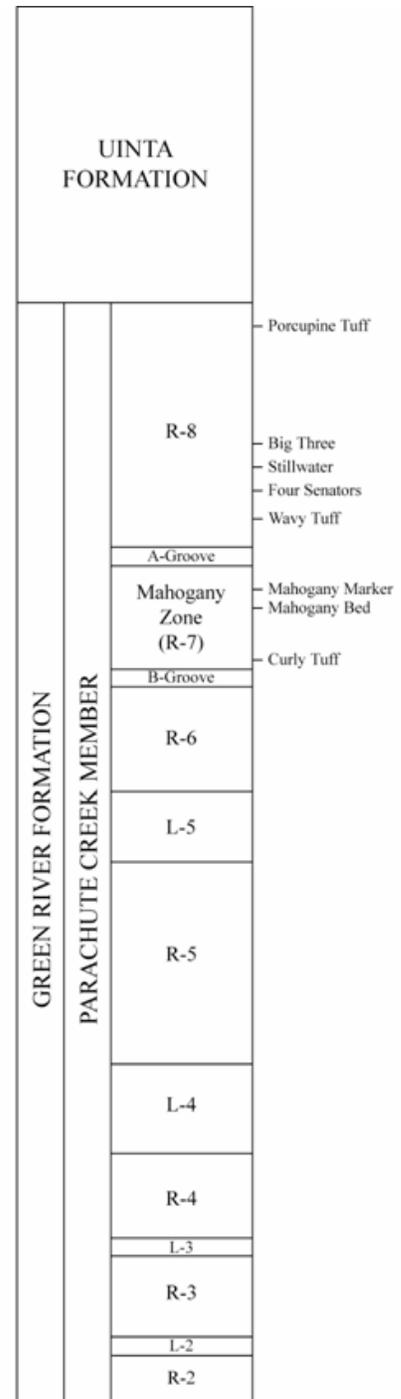


FIGURE A-2 Generalized Stratigraphic Section of the Parachute Creek Member of the Green River Formation in the Uinta Basin, Utah (“R” = rich oil shale zone; “L” = lean oil shale zone [adapted from Young 1995])

1 study of the Uinta Basin (Cashion 1967), based on less data than are available today, yielded a
 2 potential resource estimate for the Mahogany Zone that is at least 15 ft thick and contains an
 3 average yield of at least 25 gal/ton of 26.8 billion bbl (Table A-1). A more recent study
 4 (Trudell et al. 1973), based on a greater amount of drilling data but limited to the southeastern
 5 portion of the Uintah Basin, estimated that within the Mahogany Zone, which is at least 25 ft
 6 thick and contains an average of 25 gal/ton, there is a resource of at least 31 billion bbl
 7 (Table A-2). This upward resource revision indicates that the early estimate provided by Cashion
 8 (1967) is conservative, and that more work is necessary to comprehensively define the oil shale
 9 resource potential of the entire Uinta Basin.

10
 11 A major fault, the Uinta Basin boundary fault, lies in the subsurface near the northern
 12 margin of the Uinta Basin (Campbell 1975). In the Wasatch Plateau along the western margin of
 13 the Uinta-Piceance Province, several north-south fault systems that are an eastward extension of
 14 basin and range-style tectonism disrupt the geologic units. The Uinta Basin is filled by as much
 15 as 17,000 ft of Upper Cretaceous and Paleogene lacustrine and fluvial sedimentary rocks
 16 (Bradley 1925; Cashion 1967; Fouch 1985). On the Douglas Creek arch, which separates the
 17 Uinta Basin from the Piceance Basin, the Green River Formation has been eroded away.
 18 Uppermost Cretaceous and lowermost Tertiary strata dip 4° to 6° toward the axis of the Uinta
 19 Basin. The younger Uinta and Duchesne River Formations of late Eocene to earliest Oligocene
 20 age dip less steeply. The Green River Formation reaches a maximum depth of 20,000 ft along the
 21 basin axis in the north-central part of the Uinta Basin. The Green River Formation lies below the
 22 Altamont-Bluebell oil field (Fouch et al. 1994). The Green River Formation contains significant
 23 oil- and gas-producing reservoirs in the Uinta Basin, including those at Altamont-Bluebell,
 24 Cedar Rim, Brundage Canyon, Monument Butte, Eight Mile Flat North, Uteland Butte, Pariette
 25 Bench, Natural Buttes, Horseshoe Bend, and Red Wash fields. The eastern Uinta Basin also
 26 hosts significant gas-producing reservoirs in deeper Tertiary and Cretaceous reservoirs over
 27 much of the same area containing valuable oil shale deposits in the Green River Formation.
 28 Conflicts with conventional oil and gas development in the Uinta Basin may be an obstacle to the
 29 future development of Utah's oil shale deposits.

30
 31
 32 **TABLE A-1 Estimated In-Place Oil Shale Resources in the Southeastern Portion of**
 33 **the Uinta Basin Based on a Minimum Thickness of 15 ft and Various Expected Yields**
 34 **(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.

1 **TABLE A-2 Estimated In-Place Oil Shale Resources in the Southeastern Portion of the**
 2 **Uinta Basin Based on a Minimum Expected Yield of 25 gal/ton and a Minimum Thickness**
 3 **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).

4
 5
 6 The largest areal extent of the oil shale-bearing Green River Formation occurs in Utah.
 7 The richest shales in Utah occur in the east-central part of the Uinta Basin, at depths ranging
 8 from 0 ft at the outcrop to 4,800 ft below the surface. These rich deposits contain more than
 9 300 billion bbl. The existence of sodium minerals has been shown in a few Utah core holes; the
 10 extent of these minerals, however, has not been defined. The potential for conflicts between the
 11 development of sodium minerals and oil shale in the Green River Formation would need to be
 12 analyzed on a site-specific basis. The eastern Uinta Basin also contains significant deposits of the
 13 solid hydrocarbon gilsonite, which has been mined there for about 100 years and is processed
 14 and used in inks, paints, oil well drilling muds and cements, asphalt modifiers, and a wide variety
 15 of chemical products. These vertical gilsonite dikes strike between 40° and 70° west of north,
 16 have strike lengths ranging from less than 1 mi to nearly 14 mi, range in width from a fraction of
 17 1 in. up to 18 ft, and are generally found in the strata above the Green River Formation (Verbeek
 18 and Grout 1992). Conflicts may exist between the existing development of gilsonite and the
 19 future development of oil shale in the Uinta Basin.

20
 21

22 **A.1.4 Green River and Washakie Basins**

23

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

31

32 Lake Gosiute formed in a basin bounded by uplifted Precambrian, Paleozoic, and
 33 Mesozoic rocks that were uplifted to form mountains rising to about 6,500 ft above MSL
 34 (Bradley 1963). Initially, several thousand feet of fluvial sediments were deposited in the basin
 35 during the Paleocene and early Eocene. These deposits constitute the main body of the Wasatch

1 Formation, which probably accumulated on a fairly featureless alluvial plain. Continued down-
2 warping of the basin relative to surrounding mountains caused the area to become poorly
3 drained, and Lake Gosiute formed in the center of the basin, gradually expanding to an area of
4 several thousand square miles (Bradley 1964). The lacustrine Green River Formation was
5 deposited in the central part of the basin and the fluvial Wasatch Formation along the basin
6 margins. The two formations interfinger in such a way as to demonstrate three major stages in
7 the history of Lake Gosiute. The lower Tipton Member of the Green River Formation was
8 deposited during a high stand, when a large, relatively freshwater lake occupied the Basin
9 (Bradley 1964; Wolfbauer 1971). The overlying Wilkins Peak Member, however, accumulated
10 in a playa-lake complex that occupied a much smaller area (Eugster and Surdam 1973;
11 Bradley 1973; Eugster and Hardie 1975). The lake expanded following Wilkins Peak time, and
12 the Laney Member of the Green River Formation was deposited during this high-water stand
13 (Surdam and Stanley 1979). Lake Gosiute occupied the basin for several million years during the
14 early and middle Eocene, and the Laney stage of the lake may have lasted about 1 million years
15 on the basis of potassium/argon dating of tuff beds in the Wilkins Peak and Laney reported by
16 Mauger (1977). Subsequently, this basin was deformed into the Bridger, Washakie, Great
17 Divide, and Sand Wash Basins by post-middle and pre-late Eocene uplifts (Pipiringos 1961).

18
19 Additional oil shale resources are also found in the Washakie Basin east of the Green
20 River Basin. Trudell et al. (1973) report that several members of the Green River Formation on
21 Kinney Rim on the west side of the Washakie Basin contain sequences of low- to moderate-
22 grade oil shale. Two sequences of oil shale in the Laney Member, 36 and 138 ft thick, average
23 17 gal/ton and represent as much as 67,908 bbl/acre of in-place shale oil. A total estimate of the
24 resource in the Washakie Basin was not reported for lack of subsurface data.

25
26 In general, Wyoming oil shales tend to be thin and of only moderate quality. The oil shale
27 beds tend to be almost flat, and each bed shows the same basic characteristics throughout most of
28 the deposit. Most of the known Wyoming deposits of higher-grade oil shale occur in the Green
29 River Basin and are estimated to contain 30 billion bbl of shale oil. Leaner shales exist over a
30 wider area, including the entire Washakie Basin. Overburden depth ranges from 400 to 3,500 ft.
31 Trona and halite are associated with or adjacent to the shallow oil shale deposits in the Green
32 River Basin of Wyoming; however, the amount and extent of dawsonite and other saline
33 minerals have not been established. Tables A-3 and A-4 show estimated oil shale resources of
34 the Green River and Washakie Basins, respectively.

35
36 The Wilkins Peak Member of the Green River Formation in the Green River Basin in
37 southwestern Wyoming contains not only oil shale but also the world's largest known resource
38 of natural sodium carbonate, known as trona. The trona resource is estimated at more than
39 115 billion tons in 22 beds ranging from 4 to 32 ft in thickness (Wiig et al. 1995). In 1997, trona
40 production from five mines was 16.5 million tons (Harris 1997). Trona is refined into soda ash,
41 which is used in the manufacture of bottle and flat glass, baking soda, soap and detergents, waste
42 treatment chemicals, and many other industrial chemicals. One ton of soda ash is obtained from
43 about 2 tons of trona ore. Wyoming trona supplies about 90% of U.S. soda ash needs. About
44 one-third of the Wyoming soda ash is exported. Natural gas is also present in the Green River oil
45 shale deposits in southwestern Wyoming, but in unknown quantities.

1 **TABLE A-3 Estimated In-Place Oil Shale Resources in the Green River Basin Based on a**
 2 **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).

3 4 5 **A.2 HISTORY OF OIL SHALE DEVELOPMENT** 6

7 The worldwide history of oil shale applications reaches far back in time. For example,
 8 Speight (1990) reports that oil shales were sources of fuel as early as 800 A.D., oil shale deposits
 9 in what is now the British Isles were worked during Phoenician times, and applications of oil
 10 shale as fuel in Austria have been recorded as early as 1350 A.D. Commercial production of
 11 shale oil as a fuel is said to have begun in France in 1838 (Kilburn 1976; Speight 1990).
 12

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

1 **TABLE A-4 Estimated In-Place Oil Shale Resources in the Washakie Basin Based on a Minimum**
 2 **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).

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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 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

1 commercial oil shale ventures. Complementary investigations were conducted in laboratories on
2 the chemistries of kerogen, the organic fraction of oil shale, and the products of its modification
3 to produce conventional fuels through pyrolysis and upgrading activities. Thermodynamics,
4 reaction mechanisms, and kinetics of kerogen pyrolysis were defined, and relationships between
5 conditions during pyrolysis and the chemical composition of the resulting “crude shale oil” were
6 established.

7
8 With the introduction of mass production of automobiles and trucks in the United States
9 in the early 1900s, a temporary shortage of gasoline encouraged the exploitation of oil shale
10 deposits for transportation fuels. Many companies were formed to develop the oil shale deposits
11 of the Green River Formation in the western United States, especially in Colorado. Thousands of
12 oil placer claims were filed on public lands in the western United States. However, the discovery
13 and development of large deposits of conventional oil in West Texas led to the demise of these
14 early oil shale enterprises by the late 1920s (Dyner 2003).

15
16 In 1967, the DOI began an aggressive program to investigate the commercialization of
17 the Green River Formation oil shale deposits. The dramatic increase in petroleum prices resulting
18 from the Organization of Petroleum Exporting Countries (OPEC) oil embargo of 1973 triggered
19 another resurgence of oil shale activities during the 1970s and into the early 1980s. In 1974,
20 several parcels of public lands overlying oil shale resources in Colorado, Utah, and Wyoming
21 were put up for competitive bid under the Federal Prototype Oil Shale Leasing Program. Under
22 this program, oil companies leased four tracts on public lands (two in Colorado referred to as C-a
23 and C-b and two in Utah referred to as U-a and U-b). In addition to these four federal projects,
24 several projects were initiated on private lands. These projects are summarized below by state.

25 26 27 **A.2.1 Colorado Activities**

- 28
29 • ***Atlantic Richfield Company (ARCO), Ashland Oil, Shell Oil, and The Oil***
30 ***Shale Corporation (TOSCO)*** leased Tract C-b, in 1976, following the
31 withdrawal of ARCO and TOSCO from the venture, Ashland and Shell
32 submitted the first detailed development plan to the Oil Shale Project Office.
33 It outlined a conventional underground room-and-pillar method of mining
34 with surface retorting of the mined shale. In 1977, after a 1-year suspension to
35 resolve technical issues, Shell had dropped out and Occidental Oil Shale, Inc.
36 (OOSI) joined Ashland to develop the resource using OOSI’s modified in situ
37 (MIS) process. The MIS method of oil shale mining deviated from the plan
38 first described and offered enhanced recovery and a possible solution to some
39 of the technical problems that formed the basis for suspension. Ashland
40 withdrew from the project in April 1979 and Tenneco joined OOSI in
41 September 1979 to form the Cathedral Bluffs Oil Shale Company (CBOSC).
42 Tract operations began that year. Production, service, and ventilation/escape
43 shafts were sunk to a depth of 1,969 ft, holding ponds were completed, and
44 office facilities were constructed, along with a mine power substation, natural
45 gas supply building, sewage treatment plant, and a manway and utility
46 tunnels. In 1981, CBOSC announced a project reassessment, and major plan

1 construction was put on hold. In 1983, CBOSC applied for and received
2 financial assistance from the U.S. Synthetic Fuels Corporation (SFC), a
3 government-funded entity established to foster development of an oil shale
4 industry. A revised plan of development was submitted to produce 14,100 bbl
5 of shale oil per day. The detailed development plan proposed an underground
6 room-and-pillar mine, an aboveground oil shale retort, mine and surface
7 processing facilities, and an oil upgrading facility. None of this occurred,
8 however. In 1984, SFC board members stepped down, and, as a result, no
9 contract with SFC was secured. In 1985, CBOSC continued negotiations with
10 SFC. At the same time, a bill was passed in the House to abolish SFC. A
11 similar amendment in the Senate failed, 43 to 40. President Reagan signed
12 Public Law 99-190, which provided, as part of overall appropriations, for the
13 termination of SFC within 120 days, and the rescindment of all funds not yet
14 committed. In 1986, negotiations for the suspension of the Tract C-b lease and
15 shaft pumping cessation were initiated. The suspension was granted in 1987.
16 Pumping on the production and maintenance shafts stopped in 1991, and the
17 headframe was removed in 2002. No shale oil was ever produced from this
18 federal lease.

- 19
- 20 • ***Occidental Oil Shale, Inc.***, used the Logan Wash facility as a testing site for
21 the MIS process planned at Colorado lease Tract C-b and considered for
22 Tract C-a. The 10-mi² site was purchased from private sources in 1972.
23 Mining began in 1972, and by 1981, six retorts were developed and burned to
24 produce a total of 94,500 bbl of shale oil. Initial in-situ retorts on the site
25 consisted of three experimental-size operations, each producing 1,200 to
26 1,600 bbl of shale oil in total. Three considerably larger retorts, Retorts 7, 8,
27 and 8x, were constructed at Logan Wash. Retorts 7 and 8 were fired and
28 successfully produced nearly 58,300 bbl of shale oil from the 3-year,
29 \$29 million program. About 450 people were employed at the Logan Wash
30 site.
 - 31
 - 32 • ***Union Oil Company of California*** began acquiring oil shale properties in
33 Colorado around 1921 in the Parachute Creek area of the Piceance Basin north
34 of the town of Parachute in Garfield County, Colorado. Union owned the
35 mineral rights under nearly 50 mi² of oil shale lands. From 1955 through
36 1958, Union built and operated a surface retort on its Colorado properties. The
37 facility produced about 800 bbl of shale oil per day using a unique upflow
38 retort process. More than 13,000 bbl of this shale oil were successfully
39 processed into gasoline and other products at a Colorado refinery. However,
40 low crude oil prices in the 1960s prevented further process development. With
41 the rapid rise in price and uncertain availability of foreign crude oil in the
42 early 1970s, Union reactivated research and development (R&D) in its upflow
43 retorting process. Continuing improvements were made in efficiency and
44 product quality. In the fall of 1980, construction began on the first phase of
45 Union's 50,000-bbl/day oil shale facility. The first phase of the project called
46 for surface retorting of raw shale retrieved from a room-and-pillar mine.

1 Union spent more than \$1.2 billion, with substantial financial assistance from
2 the federal government. Union began production in 1984 but did not ship its
3 first barrel of oil until December 1986. Union was able to produce shale oil
4 and upgraded this shale oil to syncrude at its commercial oil shale production
5 facility at the Parachute Creek plant. Union began shipping synthetic crude
6 from its Parachute Creek plant to a Chicago refinery and was producing about
7 6,000 to 7,000 bbl/day in 1989 at its peak production, sustained by a federal
8 subsidy. The Parachute Creek plant had approximately 480 workers and 200
9 contract employees. The oil shale project was shut down in June 1991.

- 10
- 11 • ***The Exxon-TOSCO Colony Project*** was established in 1963 as a joint venture
12 among Sohio, the Cleveland Cliff Iron Company, and TOSCO. Beginning in
13 1965, various companies acquired and sold an interest in the Colony Project,
14 resulting by 1980 in ownership by Exxon Corporation (60%) and TOSCO
15 (40%). The Colony Project controlled a 22-mi² resource block. Starting in
16 1964 and ending in the early 1970s, approximately 200,000 bbl of shale oil
17 were produced experimentally at the TOSCO II Semi-Works Plant. In the
18 1960s, a prototype mine and plant operation proved the viability of the
19 underground mining plan with aboveground processing using the “TOSCO II”
20 retort method. Plans called for the mining of oil shale processed through
21 pyrolysis and the upgrading of facilities. Design and engineering work for a
22 commercial plant progressed through various stages. The underground mine
23 was to be worked with room-and-pillar methods, proceeding with the
24 conventional cycle of drilling, charging, blasting, wetting of rock piles,
25 loading, hauling, scaling, and roof bolting. Run-of-mine shale was to be
26 crushed to the desired retort feed size in two stages. Retorting and upgrading
27 facilities would recover upgraded shale oil, ammonia (NH₃), sulfur, and coke
28 from the crushed shale. Fuels produced for internal combustion would include
29 treated fuel gas, a liquid carbon stream, fuel oil, and diesel fuel. The kerogen
30 content of raw shale was to be converted into the above hydrocarbon vapors
31 and liquids using six individual “TOSCO II” retorting trains. Upgrading
32 included coking, gas recovery and treating, and hydrotreating. Exxon planned
33 to invest up to \$5 billion in a planned 47,000-bbl/day plant using a TOSCO
34 retort design. After spending more than \$1 billion, Exxon announced on
35 May 2, 1982, that it was closing the project and laying off 2,200 workers. No
36 shale oil was ever produced commercially.

- 37
- 38 • ***Gulf Oil Company and Standard Oil Company of Indiana*** leased Federal
39 Prototype Oil Shale Tract C-a from the DOI for \$210.3 million. Tract C-a was
40 the first federal tract to be leased as part of the DOI’s program to test the
41 environmental and economic feasibility of oil shale development. Tract C-a
42 was located in Rio Blanco County at the head of Yellow Creek on the western
43 edge of the Piceance Creek Basin. Gulf and Standard later formed the
44 Rio Blanco Oil Shale Company (RBOSC), a 50:50 general partnership, to
45 develop the 5,100-acre tract. Originally, Tract C-a was to be developed as an
46 open pit mine. However, the DOI did not make additional federal land

1 available for off-tract disposal of processed shale and overburden. There were
2 also air quality issues and other constraints with the pit mining concept. After
3 a 1-year suspension of operations, RBOSC decided to develop the tract by
4 underground MIS methods. In February 1979, the company purchased OOSI's
5 MIS technology. In the commercial phase, plans called for shale oil to be
6 transported to existing Gulf or Standard corporate refineries. Tract C-a was a
7 one-level operating mine, with driftwork essentially completed for three
8 underground demonstration retorts. A conventionally sunk production shaft,
9 vent shaft, service shaft, and production shaft were built. Approximately
10 500 people were employed during the construction phase of this project. In
11 October 1980, RBOSC ignited the first of three demonstration MIS retorts.
12 The burn was scheduled to last 9 weeks. The demonstration retort was ignited
13 at the top, some 670 ft below the earth's surface. This was the first burn in the
14 company's \$140-million program to demonstrate commercial feasibility of the
15 MIS technology; 1,750 bbl of oil were recovered from the first retort. Two
16 additional burns were conducted in 1981, which recovered approximately
17 23,000 bbl of shale oil. The retorts were prematurely flooded in 1984 because
18 of pump failure, and the company was unable to resume operations.
19 Approximately 150 people were employed during the operational phase of this
20 project.

- 21
- 22 • **TRW, Inc.'s** Naval Oil Shale Reserves (NOSR) Project was conducted under
23 the direction of the Secretary of Energy and included three sections of land
24 known as NOSR 1, 2, and 3. NOSR 1 and 3 were located in Colorado and
25 NOSR 2 was located in Utah. In 1977, TRW was chosen to be the prime
26 engineering and management contractor for the project, which involved
27 performing a 5-year, \$62 million resource, technology, environmental, and
28 socioeconomic assessment to advise DOE on what should be done with the
29 NOSR. The TRW, Inc., team included Gulf Research and Development
30 Company, TOSCO, C.F. Braun and Company, and Kaiser Engineers. The
31 assessment was to be completed in 1984. In September of 1980, DOE released
32 a draft EIS that discussed other fuel alternatives to oil shale and explored five
33 NOSR development approaches ranging from leasing to industry to a
34 government-owned facility. The report recommended that the biggest return to
35 the federal government would be through production of the natural gas
36 reserves.
 - 37
 - 38 • **Multi Minerals Corporation (MMC)**, a subsidiary of the Charter Company,
39 signed an agreement in April 1979 to operate a U.S. Bureau of Mines research
40 tract known as Horse Draw. MMC hoped to offset much of the expense of
41 mining oil shale by recovering nahcolite and dawsonite, two potentially
42 valuable minerals found within the shale. The company also hoped to prove
43 that its Integrated In Situ recovery method was environmentally acceptable;
44 this process reportedly did not produce spent shale residue on the surface, nor
45 did it use or contaminate surface water. In 1977 and 1978, the U.S. Bureau of
46 Mines opened an experimental mine that included a 2,370 ft-deep shaft with

1 several room-and-pillar entries in the northern part of the Piceance Basin to
2 conduct research on the deeper deposits of oil shale, which are commingled
3 with nahcolite and dawsonite. Large-scale process testing began in mid-1981,
4 when construction of the company's adiabatic retort in Grand Junction was
5 completed. The company's experimental mining involved room-and-pillar
6 mining in a bedded nahcolite and shale zone about 8 ft thick, averaging about
7 60% nahcolite. The shafts were used to obtain geologic and hydrologic data in
8 the deeper end of the Piceance Basin. The site was closed in the late 1980s.
9

- 10 • **Equity Oil Company and DOE** launched a project known as the BX In Situ
11 Oil Shale Project in 1977 to test a method of in situ retorting that frees the
12 kerogen from the shale by injecting superheated steam into the permeable
13 leached zone underlying a site owned by Equity, Exxon, and Atlantic
14 Richfield southwest of Meeker in Rio Blanco County, Colorado. Project field
15 tests began in June 1979 and continued for 2 years on a 1-acre site within the
16 1,000-acre tract owned by Equity and its partners. Steam injections for a
17 sustained period began in June 1980. By August, the formation showed signs
18 of continued and steady heating. By August 1981, 625,000 bbl of water-
19 turned-steam had been injected into 8 project wells, and approximately
20 100 bbl of shale oil had been recovered. Equity's principle oil shale interest
21 focused on the leached zone; the only zone in the Piceance Basin that has
22 native permeability sufficient to initiate in situ recovery without fracturing or
23 premining of bedrock. The injected steam process evolved from both
24 laboratory and fieldwork begun in the 1960s. These tests used natural gas
25 rather than steam. Laboratory results showed that the oil recovered was
26 superior in quality to that produced in conventional surface retorts, possibly
27 because of lower temperatures and the absence of any oxidizing gases. While
28 evaluating the project in 1970, Equity determined that superheated steam
29 could be used to lower costs. Beginning in April 1971, the BX project was
30 converted to steam, and injections were performed almost continuously until
31 the research project was suspended for financial reasons 4 months later. From
32 this latest research, Equity determined that water from the leached zone may
33 be used, thus eliminating the need to import water. Equity also found that a
34 minimum amount of surface disruption results from the construction and
35 operation of the process. With only minor alterations, the existing BX oil
36 shale site was utilized for the reactivated program in 1977. Achieving the
37 needed temperatures and pressures required a reasonably sophisticated steam-
38 generating plant, water storage facilities, and an instrumentation system to
39 monitor both equipment and project performance.
40
- 41 • **Chevron Shale Oil Company's (Chevron)** historic involvement with oil shale
42 in Colorado involves the work of three corporations: Chevron Corp, Texaco
43 Inc., and Getty Oil Company. Texaco merged with Getty in 1984, and
44 Chevron and Texaco merged in 2001. Properties were acquired by the
45 companies beginning in the 1930s, and today the combined oil shale acreage
46 totals about 100,000 acres in Mesa and Garfield Counties. The lands are

1 managed by Chevron Shale Oil Company, a division of Chevron USA, Inc.
2 Early work by Chevron was mainly resource evaluation and mapping. In the
3 1970s, Chevron and Texaco participated in a consortium of companies that
4 supported the Paraho Oil Shale Project at the Anvil Points facility, west of
5 Rifle, Colorado. The surface retort produced more than 100,000 bbl of shale
6 oil for the U.S. Navy. In 1981, Chevron Shale Oil Company and Conoco
7 Shale Oil, Inc., began the Clear Creek project on a 25,000-acre tract of private
8 land north of DeBeque. Chevron Shale Oil Company was the operator. The
9 goal of the project was to produce 100,000 bbl of shale oil by the mid-1990s.
10 The oil shale was to come from an underground mine, which started
11 construction in 1981. The company developed a second-generation surface
12 retorting process called the Staged Turbulent Bed at its Richmond, California,
13 laboratory. Tests were made using a 1-ton/day and a 4-ton/day plant. The next
14 phase was the Semi-Works Development Project. A 350-ton/day retort was
15 constructed and successfully tested at the Chevron refinery near Salt Lake
16 City, Utah. Crushed rock was moved to the retort by rail. A small amount of
17 shale oil was produced, but because of the drop in oil prices, mine
18 construction was halted in 1984. The commercial phase of the project was not
19 reached, and the mine has remained closed.
20
21

22 **A.2.2 Utah Activities**

23

24 In Utah, six oil shale projects were planned that progressed to various stages of
25 development. The six projects are described below (DOE 1981). From 1954 through 1990,
26 several companies and governmental agencies drilled at least 200 oil shale exploration wells in
27 the Uinta Basin and conducted Fischer assays on the oil shale core samples. In addition to the
28 core samples, the USGS had an oil shale program from the late 1950s through the 1970s that
29 collected cutting samples from more than 400 oil and gas wells penetrating the oil shale-bearing
30 portion of the Green River Formation. Fischer assays also were conducted on those samples.
31 Data on the thickness, depth, and Fischer assay information exist for the oil shale interval in the
32 Parachute Creek Member of the Green River Formation from more than 600 wells spread across
33 the Uinta Basin, but mainly from the southeastern quarter of the basin.
34

- 35 • **Geokinetics, Inc.**, was originally organized in 1969 as a minerals
36 development company; it was reorganized in 1972 as a joint venture with a
37 group of independent oil companies to develop an in situ technique to extract
38 shale oil. The company began design and cost studies of a horizontal modified
39 in situ process in preparation for the anticipated Federal Prototype Oil Shale
40 Lease Program sale. Small-scale pilot tests in steel retorts were carried out to
41 simulate the horizontal process in 1974 and early 1975. Starting in April 1975,
42 field tests of the in situ method were carried out, and by late 1976 the basic
43 parameters for an in situ process were established. From 1977 through 1979,
44 the process was scaled up substantially from early tests, and rock-breaking
45 designs for the underground retorts were improved and tested. From 1980
46 through 1982, Geokinetics, funded in part by DOE, blasted 24 experimental

1 underground retorts and tested them. These tests cumulatively produced
2 15,000 bbl of oil. By 1982, the company had settled on a 2,000-bbl/day design
3 for its commercial retort and had acquired 30,000 acres of nonfederal leases,
4 with an estimated resource of 1.7 million bbl of oil (averaging 20 gal/ton).
5 Between 1972 and 1982, the company drilled at least 32 core holes on its
6 leases in the Uinta Basin and conducted Fischer assays on oil shale samples
7 from those wells.
8

- 9 • ***Magic Circle Energy Corporation*** acquired the 76,000 acres of State of Utah
10 leases composing the Cottonwood Wash properties from the Western Oil
11 Shale Corporation in July 1980 through an exchange of stock. The
12 Cottonwood Wash properties contained an estimated 2.1 billion bbl of oil with
13 a grade in excess of 15 gal/ton, and at a depth between 1,500 and 2,000 ft.
14 Magic Circle spent more than \$1 million to perform feasibility studies, initiate
15 permit applications, and perform initial coring for resource definition, mine
16 design, and environmental evaluation, but no mine or plant construction or oil
17 shale production took place on this project.
18
- 19 • ***Paraho Development Corporation*** was organized in Grand Junction,
20 Colorado, in 1971, to develop oil shale technology. The company acquired
21 leases along the White River in Utah near the border with Colorado, but no
22 work was performed on the property. The company conducted several retort
23 research projects in Colorado with several other industry partners to achieve
24 an oil recovery averaging 90% of the in-place oil. On the basis of this
25 research, the company was contracted by DOE to produce 100,000 bbl of
26 shale oil. Paraho used the Anvil Points facility to conduct a 105-day
27 continuous-stream operation in the late 1970s that produced the contracted
28 amount of shale oil with 96% oil yields. The oil market deteriorated before a
29 commercial plant could be permitted and built on the Utah leases.
30
- 31 • ***Syntana-Utah*** was a joint venture of the Synthetic Oil Corporation and
32 Quintana Minerals Corporation that was formed in late 1980. This venture
33 acquired a State of Utah lease on Section 16, T9S, R25E, on which it planned
34 to construct an underground mine and surface retort operation that could
35 produce 24,500 tons/day of 25 gal/ton oil shale. Limited effort was spent
36 identifying the depth, thickness, and grade of the oil shale to quantify the oil
37 shale resource on the lease. Two, and perhaps more, drill holes were
38 completed on the property to facilitate mine and retort engineering design.
39
- 40 • ***TOSCO Development Corporation*** acquired 29 separate State of Utah oil
41 shale leases totaling 14,688 acres of land about 35 mi south of Vernal, Utah.
42 These leases were generally located in T9S and T10S, and R21E and R22E.
43 Between 1977 and 1981, TOSCO drilled eight or more core holes to help
44 define the oil shale resource and to initiate basic actions leading to a site-
45 specific EIS for a 66,000-ton/day mine with a production capacity of
46 47,000 bbl/day employing multiple TOSCO II retort facilities. Subsequent

1 deterioration of oil prices led to the cancellation of the project before final
2 permitting and construction began.

- 3
- 4 • **White River Shale Oil Corporation (WRSOC)** was a joint venture of three
5 major oil companies: Phillips, Sohio, and Sunoco. Sunoco and Phillips were
6 the successful bidders for the 5,120 acres composing the U-a federal lease
7 tract that sold for \$75.6 million at the 1974 Federal Prototype Oil Shale Lease
8 Program sale. Shortly after the first sale, Sohio joined the venture and the
9 WRSOC was formed. In 1975, the group paid an additional \$45.1 million and
10 acquired the 5,120-acre U-b tract that was adjacent to the U-a tract. Between
11 1974 and 1976, the WRSOC drilled 18 wells on its leases and created a
12 detailed development plan that was submitted to the federal government in
13 mid-1976. The development plan called for a 179,000-ton/day mine that
14 would be supported by a 100,000-bbl/day surface retort at full commercial
15 operation. Later that year, the leases were suspended because of
16 environmental and land title issues and remained suspended until the early
17 1980s. Once these issues were resolved, the venture ultimately constructed
18 mine service buildings, water and sewage treatment plants, and a
19 1,000-ft-deep vertical shaft and inclined haulage way to the high-grade
20 Mahogany Zone of oil shale. Several tens of thousands of tons of oil shale
21 were extracted to test mining conditions and retort technology and economics.
22 The project was abandoned before commercial operations were achieved
23 when market conditions deteriorated in the mid-1980s.
- 24

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

31

32

33 **A.3 TECHNOLOGY OVERVIEW**

34

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

46

1 Development of oil shale resources fundamentally occurs in three major steps:
2 (1) recovery or extraction from the natural setting, (2) processing to separate organic and
3 inorganic constituents, and (3) upgrading the organic components in anticipation of further
4 refining into conventional fuels. The physical and chemical features of oil shale deposits and
5 other circumstantial factors associated with their deposition compose the economic and
6 engineering parameters that dictate the most appropriate development schemes. Typical
7 development schemes always involve each of the above major steps, although many
8 permutations of these steps are possible and many interim steps may also be necessary. This
9 appendix provides descriptions of each of these major actions, the technologies that have been
10 developed for each, their advantages and disadvantages, and their potentials for environmental
11 impact.

14 **A.3.1 Recovery of Oil Shale**

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

31 **A.3.1.1 Direct Recovery Mining Technologies**

33 Surface mining techniques (e.g., strip mining and/or pit mining) as well as subsurface
34 mining techniques (e.g., room-and-pillar mining, longwall mining, and other derivatives) have
35 been successfully employed in the recovery of oil shale. For oil shale deposits relatively close to
36 the surface, conventional strip mining technologies could be employed to retrieve the oil shale.
37 As discussed in Section A.1, the BLM has limited its evaluation of the impacts of surface mining
38 for oil shale to areas within the most geologically prospective oil shale areas where the
39 overburden ranges in thickness from 0 to 500 ft. The areas where the overburden is 0 to 500 ft
40 that potentially will be made available for application for leasing using surface mining
41 technologies are limited to part of the Uinta Basin in Utah and parts of the Green River and
42 Washakie Basins in Wyoming (Figure A-1). Surface mining will not be considered in Colorado
43 because the distribution of areas where the overburden thickness is less than 500 ft is dispersed
44 enough as to make it difficult to assemble a logical mining unit. In Utah, about 133,194 acres of
45 land within the most geologically prospective oil shale area have an overburden thickness of 0 to
46 500 ft. In Wyoming, the corresponding area includes about 380,220 acres.

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

11
12 Both strip mining and pit mining can be successfully applied to near-surface deposits
13 with generally flat formation orientations. Both methods use similar types of equipment: shovels,
14 bucket-wheel excavators, draglines, conveyors, trucks, scrapers, etc. The most probable
15 combination of mining equipment would involve diesel-powered shovels loading materials into
16 haul trucks ranging in size from 240- to 400-ton capacity.

17
18 Pit mining does not typically require any ventilation or special considerations for the
19 presence of methane (CH₄); it does, however, typically utilize explosives to rubblize the
20 formation before removal. Both surface mining methods impact significant land areas. Both
21 require separate areas for temporary storage of overburden. Strip mines are often developed in
22 such a manner that previously evacuated areas can be used to receive processing waste (retort
23 ash); however, operations involving pit mines must utilize a separate area for retort ash disposal.

24
25 According to Nowacki (1981), technological benefits of surface mining can include:

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

34
35 However, environmental impacts can be significant, including:

- 36 • Substantial land areas disturbed, loss of habitat (both at the working face and
37 at stockpile areas);

38
39
40
41
42
43
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.

- 1 • Substantial amounts of overburden and spent shale requiring management;
- 2
- 3 • Potential for ground and surface water impacts (pollution as well as altered
- 4 drainage patterns);
- 5
- 6 • Potential for air quality impacts from fugitive dust as well as from operation
- 7 of equipment, much of which utilizes internal combustion engines;
- 8
- 9 • Noise impacts from equipment vehicle operations, especially crushing and
- 10 grinding operations and the use of explosives to loosen materials before
- 11 removal (when necessary);
- 12
- 13 • Initial capital investment that may be high (necessarily very large
- 14 mining/haulage equipment) to ensure high productivity; and
- 15
- 16 • Land reclamation programs that may extend well beyond cessation of mining
- 17 operations (adapted from Nowacki 1981).
- 18

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

30
31 For deeper deposits where surface mining is infeasible or prohibitively expensive, or for
32 deep deposits that are accessible through outcrops along erosion faces, room-and-pillar mining
33 techniques such as those used in coal mining have been successfully applied. The typical cycle
34 of activities in room-and-pillar mining involves drilling, charging, blasting, wetting, crushing,
35 loading, hauling, scaling, and roof bolting (DOE 1982).

36
37 Ventilation is necessarily continuous in virtually all room-and-pillar mining operations
38 to provide for worker safety and is essential in "gassy" mines where explosive methane gas is
39 present at concentrations greater than 1%. The excavated rooms are typically 60 ft wide by 90 ft
40 high. Pillars (undisturbed formations) are 30 to 45 ft thick, depending on the engineering
41 parameters of the particular formation and structural support demands dictated by the amount
42 and type of overburden. In general, as much as 75% of the shale can be recovered by using this
43 technique, especially in shallower formations (DOE 1982). Access to the mine is either by shaft,
44 decline, adit, or a combination thereof.

45

1 Infrastructure necessary to support underground mining includes systems for both process
2 and potable water, conveyor systems, crushing systems, and haulage systems. Mixtures of
3 ammonium nitrate and fuel oil are typically used to rubble the formation prior to crushing.
4 Typically, primary and even secondary crushing are conducted within the mine before oil shale
5 is brought to the surface. Pumping systems to manage formation water are also typically present.
6 Electric power and vehicle/equipment fuels (typically diesel) are also required. A variation on
7 this technique, chamber-and-pillar mining, has also been advanced. In chamber-and-pillar
8 mining, chambers are cut perpendicular to the main entry shaft. This technique offers particular
9 advantages to oil shale mining in that the chamber heights can be variable, in accordance with
10 formation geometries, and, once excavated, the chamber may serve as a convenient disposal area
11 for spent oil shale. Essentially the same types of support equipment are required for chamber-
12 and-pillar mining as for room-and-pillar mining.

15 **A.3.1.2 Indirect or In Situ Recovery Techniques**

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

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

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.

1 Intrusion into and alteration of the formation are somewhat greater for MIS techniques.
2 Typically, explosives are introduced to enhance the degree of natural fracturing, thus facilitating
3 the flow of kerogen decomposition products to points of extraction. Subsequently, anywhere
4 from 10 to 30% (by volume) of the formation is mined by conventional techniques (and later
5 processed above ground) to create voids in the formation that serve as retorting chambers from
6 which the formation is heated and at or near which the mobilized kerogen is accumulated and
7 extracted. First-generation in situ heating technologies were designed to mobilize the kerogen in
8 the formation by reducing its viscosity while not changing its chemical composition. However,
9 the majority of investigations into in situ heating technologies focused not only on the
10 mobilization of kerogen, but also its pyrolysis. Such in situ pyrolysis techniques are discussed in
11 Section C.3.2.

12
13 Enhanced oil recovery (EOR) technologies developed for the conventional crude oil and
14 tar sands industries also have potential application to oil shale recovery. Both secondary and
15 tertiary techniques have been developed. Secondary techniques essentially involve mechanical
16 displacement of oil by the use of high-pressure immiscible gases or water. Waterflooding and
17 high-pressure gas flooding are examples. Tertiary EOR techniques can be grouped into two
18 categories: miscible techniques and thermal techniques. Miscible techniques involve the
19 introduction of materials that dissolve the oil, increasing its ability to move through the
20 formation to a recovery well. Thermal techniques introduce heat, lowering the oil's viscosity,
21 thus facilitating its movement through the formation. Solvent flooding may involve the use of
22 such materials as raw naphtha, a collection of light molecular weight aliphatic hydrocarbons, that
23 is a principal feedstock for gasoline or other products of partial crude oil refining. Tertiary
24 techniques often follow or are superimposed upon secondary techniques. For example, the
25 injection of high-pressure steam combines a secondary displacement technique with a tertiary
26 thermal technique. Many of these techniques have also been successful in enhancing the
27 recovery of bitumen⁷ from tar sands. While most of these techniques are typically applied near
28 the end of the useful life of a conventional crude oil deposit, they can be used for dislodging or
29 mobilizing kerogen in the early phases of formation development, either alone or in conjunction
30 with the conventional heating technologies discussed above. Overviews of some of the most
31 promising EOR technologies are provided below. More detailed discussions of EORs can be
32 found in *Enhanced Oil Recovery; Secondary and Tertiary Methods* (Schumacher 1978) or any of
33 the numerous other technical publications on these technologies.

- 34
35 • **Steam Injection Technologies.** Steam injection has been used for decades to
36 enhance recovery of crude oil or to mobilize heavy oils for retrieval. One such
37 technology adapted to recovery of bitumen from tar sand, cyclic steam
38 stimulation (CSS), may be applicable to oil shale recovery. CSS involves the
39 injection of steam at high pressure and temperature into the deposit, causing
40 the oil sand to fracture, simultaneously lowering the viscosity of the bitumen
41 as it absorbs heat from the steam. The fluidized bitumen is then recovered by
42 strategically placed conventional liquid recovery wells, together with steam

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.

1 condensates. Steam injections are repeated over time until all of the bitumen is
2 recovered.

3
4 A second widely used steam injection technology, steam-assisted gravity
5 drainage (SAGD), is being used for retrieval of bitumen from tar sands in the
6 vast deposits occurring in Alberta and Saskatchewan Provinces in Canada.
7 SAGD is closely related to CSS in its technological approach; however, its
8 mechanisms for recovery of mobilized/liquefied resources are unique. SAGD
9 consists of two horizontal wells, a production well near the bottom of the
10 formation and a steam injection well approximately 6 m above and aligned
11 with the production well. Steam is circulated between the two wells, causing
12 heating of the intervening formation by conduction. Once communication is
13 achieved, the steam rises in the formation because of its relatively light
14 density, heating the formation above the injection well. The heated oil, steam
15 condensate, and formation water are then collected in the production well.

- 16
- 17 • **Waterflooding.** As the name implies, waterflooding involves the injection of
18 water at high pressure to mechanically displace oil from rock pores and
19 fissures. The process can also enhance formation permeability by
20 hydrofracturing (or hydraulic fracturing), causing additional fractures in the
21 formation through increases in hydrostatic pressure. Waterflooding and
22 hydrofracturing are relatively inexpensive but require extensive amounts of
23 water.
24
 - 25 • **High-Pressure CO₂ Flooding.** This technology applies carbon dioxide (CO₂)
26 at high pressures as a follow-on to in situ retorting and has two distinct
27 advantages: displacement and removal of additional kerogen decomposition
28 products not recoverable through conventional mining techniques or in situ
29 heating techniques, and the possible sequestration of CO₂ released from the
30 operation of various combustion sources to produce process steam or power.
31 One of the potential large environmental impacts from oil shale development
32 is the release of copious amounts of CO₂ during retorting and/or formation
33 heating. Carbon dioxide has been used successfully in crude oil production as
34 an effective enhanced recovery technique. After displacing crude oil from
35 rock pores, the CO₂ is bound indefinitely within those pores. Such
36 sequestration may therefore be a valuable pollution control mechanism for oil
37 shale development, while at the same time improving kerogen recovery
38 efficiencies.
39
 - 40 • **Solvent Flooding.** Solvent flooding technologies are similar to steam injection
41 technologies, substituting solvents for steam and relying on chemical
42 dissolution of the kerogen rather than liquefaction through use of steam.
43 Various organic solvents can be used. Solvent flooding is often performed
44 with two horizontally oriented wells: an upper well into which the solvent is
45 injected, and a lower well from which kerogen, diluted with solvent, and, in
46 some cases, partially upgraded, can be recovered. Other well combinations for

1 solvent injection and product recovery have also proven successful. Solvent
2 injection offers a number of important benefits over steam injection: (1) little
3 to no processing water is required; (2) the technique involves lower capital
4 costs since steam does not need to be produced, recovered, and recycled;
5 (3) the solvent and potentially higher organic recovery rates are possible; and
6 (4) partial upgrading of the kerogen may result from its interactions with the
7 solvents selected. However, solvent injection also has some drawbacks. The
8 solvent must be recoverable for the process to be economically viable, and
9 any solvent not recovered represents a potential for groundwater
10 contamination.

11

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

35

36 Raytheon has successfully developed a RF heating technology for application
37 to oil shale recovery (Cogliandro 2006; see also Raytheon 2006). Field
38 experience indicates that this technology results in rapid heating and
39 volatilization of water, which, in turn, results in microfracturing of the
40 formation, enhancing formation permeability and product recovery.
41 Consequently, no preliminary steps designed to remove the majority of free
42 formation water are necessary. Experience to date indicates that the Raytheon
43 RF heating technique could be successfully applied to exploit formations with
44 as little as 150 ft of overburden (the minimum thickness needed to prevent
45 “bleeding” of induced RF energy at the surface). Applying the RF heating
46 technique, Raytheon has obtained recovery rates of 75% of the oil shale’s

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>.

1
2
3 Fisher assay value. Some upgrading of initial kerogen pyrolysis products has
4 also been observed. However, in its latest form, the Raytheon RF heating
5 technique is intended to be used in conjunction with the injection of
6 supercritical CO₂ to enhance product recovery. Coupling those technologies
7 has resulted in recovery rates as high as 90 to 95%.⁸

- 8
9 • **Chemically Assisted Recovery Techniques.** Various chemicals have been
10 used successfully to enhance the recovery of crude oils. The chemicals
11 selected perform various functions, acting as surfactants, electrolytes, mobility
12 buffers, diluents, or blocking agents that effectively block exchange sites in
13 the formation for which oil molecules have an affinity. The selection of
14 chemicals is based on a number of factors, including cost and availability of

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

1 the chemicals, compatibility of the chemical with the formation, and various
2 other logistical factors. Chemicals such as hydrazine and hydrogen peroxide
3 have been used to initiate thermal recovery, while quinoline, sodium
4 hydroxide, and toluene have been used to enhance thermal recovery initiated
5 by other means (Schumacher 1978).
6

7 Experience using chemicals to enhance kerogen recovery is much more
8 limited than it is for crude oils, but some of the concepts on which these
9 chemically enhanced recovery technologies are based may be relevant to oil
10 shale recovery. DOE-sponsored research carried out at Argonne National
11 Laboratory investigated the specific manner in which kerogen molecules were
12 bound to minerals in oil shale. Understanding the nature of this bonding
13 would allow development of chemically enhanced recovery methods, since
14 chemical attack of such bonds would, in theory, release the kerogen
15 (Vandegrift et al. 1980). Follow-up investigations at the University of
16 Colorado, Boulder, conducted laboratory-scale recovery of kerogen using
17 solutions of 10% hydrogen chloride, 80% steam, and 10% CO₂ injected into
18 shale samples at moderate pressures (Ramirez 1989). Some of the results were
19 promising, producing yields of 80% and, in one instance, better than 90% of
20 the Fisher assay value for the kerogen. The researchers concluded that
21 chemically assisted recovery had promise, but that a key to its success was a
22 dynamic flushing of the formation rather than a simple saturation of the
23 formation with the chemical solution selected. No further research using
24 similar solutions has been undertaken, however.
25
26

27 **A.3.2 Processing Oil Shale**

29 Processing oil shale involves two steps: (1) retorting to separate the organic and inorganic
30 fractions and cause initial chemical transformations in the organic fraction (Section A.3.2), and
31 (2) upgrading the resulting organic retorting products through additional chemical reactions until
32 materials generally equivalent to conventional fuels are produced (Section A.3.2). Myriad
33 physical, chemical, logistical, and environmental issues must be understood and managed for any
34 given process to be technologically successful. Numerous technologies have been advanced for
35 retorting and subsequently upgrading oil shale. However, the heterogeneous nature of oil shale
36 virtually guarantees that no one retorting technology will be best in all circumstances, and further
37 guarantees that a technology's performance at one location depends on a variety of site-specific
38 factors. In addition to their impact on the yield and quality of final products, many technological
39 issues also greatly influence economics. Availability of support resources such as electric power,
40 heat, processing water, and reactants for use in upgrading reactions, as well as the nature of
41 resulting environmental impacts and requirements for their control or mitigation, greatly impact
42 the overall success, practicability, and cost of any given technology. Energy and environmental
43 efficiencies of oil shale processing technologies play as important a role as the richness and
44 accessibility of the oil shale resource.
45

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

10
11 When the oil shale resource is extracted from its formation for ex situ processing, a
12 certain number of preliminary preparatory steps may be required before retorting or upgrading
13 can occur. These might involve separating the oil shale from other extraneous materials and free
14 water and crushing it to the uniform particle size specified by the retorting process being used.
15 Primary and secondary crushing can take place within a subsurface mine before the materials are
16 brought to the surface. Uniform particle size of oil shale results in better retorting efficiencies
17 and better overall efficiencies in materials management. When the raw resource has been
18 retrieved from its formation as a liquid through in situ formation heating or other in situ recovery
19 technologies, crushing and sizing are obviously not required; however, other actions such as
20 separation of water (e.g., the small amount of formation water that entered the retort zone after
21 heating commenced, as well as the water produced in kerogen pyrolysis and condensate that
22 results when steam is used to heat the formation) and removal of entrained fine particulates are
23 necessary prior to any retorting. All such crushing, sizing, and separating technologies are
24 considered to be generic to resource mining and are not otherwise mentioned in the following
25 discussions of particular retorting or upgrading technologies unless they have been shown to play
26 especially critical roles in that technology's overall performance.

27
28 Organic fractions of oil shale are separated from the mineral fraction through a process
29 known as retorting. During retorting, kerogen is released from the mineral surface to which it is
30 adsorbed and subsequently undergoes chemical transformations in a process known as pyrolysis.
31 When direct recovery methods are used (e.g., surface or subsurface mining), retorting the
32 recovered oil shale causes thermal desorption of the organic fractions from the mineral fractions
33 and the subsequent destructive distillation or pyrolysis of kerogen, which produces three product
34 streams: crude shale oil (a collection of condensable organic liquids); flammable hydrocarbon
35 gases; and char, a solid fraction of organic material that typically remains adsorbed to the
36 mineral fraction of the shale. The char has limited value as an energy source for production of
37 distillate fuels and is typically not further processed, although some retort designs call for it to be
38 burned as a heat source for processing subsequent batches of mined oil shale. The liquid and
39 gaseous products from retorting undergo additional processing to make them suitable for further
40 refining off the mine site or for use on-site as fuel to sustain the mining and retorting operations.
41 When recovery techniques are employed, only the kerogen or its pyrolysis products are
42 recovered, and any subsequent aboveground retorting is conducted simply to complete kerogen
43 pyrolysis. As will be discussed later, some MIS techniques have been specifically designed to
44 accomplish in situ pyrolysis of kerogen. The extent to which that pyrolysis occurs in situ will
45 determine the need for further ex situ processing of recovered organic materials.

46
47

1 **A.3.2.1 Aboveground Retorting Technologies**

2
3 Initial attempts at oil shale pyrolysis were conducted in aboveground retorts (AGRs) by
4 using designs and technical approaches that had been adapted from technologies developed for
5 other types of mineral resource recoveries. There are numerous configurations for AGRs; these
6 are differentiated by the manner in which they produce the heat energy needed for pyrolysis, how
7 they deliver that heat energy to the oil shale, the manner and extent to which excess heat energy
8 is captured and recycled, and the manner and extent to which initial products of kerogen
9 pyrolysis are used to augment subsequent pyrolysis. Technologies include both direct and
10 indirect heating of the oil shale. In direct heat retorting, some of the oil shale, char-bearing spent
11 shale from previous retorting cycles, or some other fuel is combusted to provide heat for
12 pyrolysis of the remaining oil shale, with the flame impinging directly on the oil shale
13 undergoing retorting. Indirect heating, the more widely practiced alternative, involves the use of
14 gases or solids that have been heated externally using a separate imported fuel or energy source
15 and then introduced into the retort to exchange heat with the oil shale. Indirect heat sources
16 include hot combustion gases or ashes from combustion of an external fuel, ceramic balls that
17 have been heated by an indirect source, or even the latent heat contained in retort ash from
18 previous retort cycles. The flammable hydrocarbon gases and hydrogen produced during
19 retorting are also sometimes burned to support the heating process. While all retorts will produce
20 crude shale oil liquids, hydrocarbon gases, and char, some have been designed to further treat
21 these hydrocarbon fractions to produce syncrude. Other retorting processes contain auxiliary
22 features to treat problematic by-products such as nitrogen- and sulfur-containing compounds; in
23 some cases, they even convert these compounds to saleable by-products.
24

25 Comprehensive technical reviews of AGRs are contained in numerous reports published
26 by or on behalf of various federal agencies, including DOE, the U.S. Environmental Protection
27 Agency (EPA), and the U.S. Congress OTA (DOE 1982, 1983, 1988, 2004a,b; EPA 1977, 1979;
28 NTIS 1979; OTA 1980a). Other technical reviews of AGRs also exist in the open literature
29 (Heistand and Piper 1995).
30

31 Government-sponsored work in the development of AGRs specifically designed for oil
32 shale was conducted in the 1960s under the direction of the U.S. Bureau of Mines. The gas
33 combustion retort (GCR) was the design originally selected by U.S. Bureau of Mines for initial
34 development of the Green River Formation oil shale at its demonstration mine at Anvil Points,
35 Colorado. The GCR was a counterflow direct combustion retort. In addition to a relatively
36 simple design and generally high production efficiencies, the most important advantage of GCRs
37 is that they do not require cooling water, which makes them an excellent fit for the arid regions
38 in which the majority of the Green River Formation oil shale exists. The U.S. Bureau of Mines-
39 led project to develop the GCR involved a consortium of six commercial oil corporations: Mobil
40 Oil, Humble Oil, Pan American, Sinclair, Phillips, and Continental Oil. The U.S. Bureau of
41 Mines GCR designs were the models for many commercial direct combustion counterflow
42 retorts, including the Paraho Direct Mode Retort. Development of the GCR was completed in
43 1967, before the promulgation of the National Environmental Policy Act (NEPA). Consequently,
44 while some environmental impacts of the GCR were identified and measured, a comprehensive
45 appreciation of its environmental impact was not established. However, environmental impacts

1 from direct descendants of the GCR, such as the Paraho Direct Mode Retort, have been
2 extensively defined and quantified.

3
4 AGRs have typically assumed the names of the RD&D projects in which they were
5 developed, the corporation that conducted the RD&D, or their original inventors. At least eight
6 separate retort designs have been developed to pilot stages, while only a few have reached
7 commercial-scale applications. The following text, taken largely from the most recent DOE
8 review (DOE 2004) and from an EPA review (EPA 1979), provides information on a
9 representative cross section of AGR technologies previously developed for application in the oil
10 shale industry. The AGRs that collectively compose a representative sample of AGR technology
11 include Union B, TOSCO II, Paraho (both direct and indirect modes), the Lurgi-Ruhrgas
12 process, and Superior Oil's circular grate retort. Also included is a description of the Alberta
13 Taciuk Process (ATP) technology, which was originally developed for processing tar sands but is
14 currently being proposed for use in oil shale development.

15
16
17 **A.3.2.1.1 Union B Retort.** This retort was developed by the Union Oil Company of
18 California (Unocal). It is an example of hot inert gas retorting. Crushed shale (0.32 to 5.08 cm
19 [0.13 in. to 2.00 in.]) is fed through two chutes to a solids pump that moves shale upwards
20 through the retort. The shale is heated to retorting temperatures by interaction with a counterflow
21 of hot recycle gas [510 to 538°C (950 to 1,000°F)], resulting in the evolution of oil shale vapor
22 and gas. Heat is supplied by combustion of the organic matter remaining on the retorted oil shale
23 and is transferred to the (raw) oil shale by direct gas-to-solids exchange. The process does not
24 require cooling water. This mixture is forced downward by the flow of recycle gas and cooled by
25 contact with cold shale entering the retort in the lower section of the retort. Gas and condensed
26 liquids are captured and separated at the bottom of the retort. Liquids are removed. Gases are
27 sent to a preheater and returned to the retort for recovery of heat energy by burning. The captured
28 liquids are further treated for removal of water, solids, and arsenic salts. Once the system reaches
29 equilibrium, no external fuel is required; heat is supplied by the combustion of hydrocarbon
30 gases produced during retorting. Pollution control devices are integrated into the design for
31 removal of hydrogen sulfide (H₂S) gas and NH₃ gas produced during retorting and for treatment
32 of process waters recovered from oil/water separations. Treated waters are recycled, used for
33 cooling the spent shale, or delivered to mining and handling operations and used to moisten the
34 shale for fugitive dust controls.

35
36 The Union B Retort design offers particular advantages. The reducing atmosphere
37 maintained in the retort results in the removal of sulfur and nitrogen compounds through the
38 formation of H₂S and NH₃ gas, respectively, both of which are subsequently captured. Forcing
39 the hot, newly formed oil vapors to immediately contact the cooler shale entering the retort
40 results in their rapid quenching. This is thought to minimize polymer formation among the
41 hydrocarbon fractions, improving not only the overall yield of crude shale oil but also its quality.
42 Additional treatment of the initially formed shale oil and the removal of heavy metals, such as
43 arsenic, results in a final product recovered from the retort that can be used directly as a
44 low-sulfur fuel or delivered to conventional refineries for additional refining.

45
46

1 **A.3.2.1.2 TOSCO II Retort.** The TOSCO II Retort, developed by The Oil Shale
2 Corporation, is more correctly described as a retorting/upgrading process. Its design is unique in
3 two respects: it is one of only a few retorts that have operated in the United States that employ a
4 solid-to-solid heat exchange process, and it is the only process that fully integrates oil shale
5 retorting and shale oil upgrading steps to produce an upgraded syncrude, as well as liquefied
6 petroleum gas (LPG) and saleable sulfur, NH₃, and coke by-products. Although they are
7 independent of each other, the retort and the various upgrading units are designed to work
8 together.
9

10 Crushed and sized (nominally to 1/2 in.) raw oil shale is preheated to 500°F by
11 interaction with flue gases from a ceramic ball heater. The preheated shale is introduced into a
12 horizontal rotary kiln together with 1.5 times its weight in previously heated ceramic balls. The
13 temperature of the shale is raised to its minimal retort temperature of 900°F. The kerogen is
14 converted to shale oil vapors that are withdrawn and fed to a fractionator for hydrocarbon
15 recovery and water separation. Spent shale and the ceramic balls are discharged and separated;
16 the ceramic balls are returned to their heater; and the spent shale is cooled, moistened for dust
17 control, and removed for land disposal. The fractionator separates the shale oil hydrocarbon
18 vapors into gas, naphtha,⁹ gas oil, and bottom oil. The gas, naphtha, and gas oil are sent to
19 various upgrading units, while the bottom oil is sent to a delayed coking unit, where it is
20 converted to lighter fractions and by-product coke. Gas oil and raw naphtha are both upgraded in
21 separate hydrogenation units through reaction with hydrogen at high pressure. The hydrogen is
22 actually produced on-site from steam reforming of the fuel gas originally recovered from the
23 retort. In addition to improving the H/C ratio of the hydrocarbons, the hydrogenation units also
24 convert any sulfur present to H₂S and any nitrogen present to NH₃. The NH₃ is captured for sale,
25 while the H₂S is sent for further treatment, where it is converted to saleable sulfur. Other
26 saleable products from the hydrogenation units include LPG and butane.
27
28

29 **A.3.2.1.3 Paraho Retorts.** The Paraho retorts, developed by Development Engineering,
30 Inc., have been in service in oil shale fields in both Colorado and Brazil. Two versions exist,
31 direct mode and indirect mode, both utilizing vertical retorting chambers. In the direct mode
32 retort, some of the raw shale is ignited in the combustion zone of the retort to produce the heat
33 that pyrolyzes the remaining oil shale present in higher zones. The Paraho direct mode retort is
34 an example of the U.S. Bureau of Mines GCR. In the indirect mode retort, heat is generated in a
35 separate combustion chamber and delivered to lowermost portion of the retorting chamber.
36

37 In the direct mode Paraho retort, crushed and sized oil shale is fed into the top of the
38 vertical retorting vessel. At the same time, spent shale (previously retorted oil shale that contains
39 solid carbonaceous char) is ignited in a lower level of the retort. Hot combustion gases rise
40 through the descending raw shale to pyrolyze the kerogen. Oil vapors and mists formed in the
41 uppermost portion of the retort are removed. The liquid fraction is captured for further upgrading

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).

1 in independent facilities. The gaseous fraction is cleaned for sale, while a small portion is
2 returned to the retort and combusted together with the spent shale.
3

4 In the indirect mode Paraho retort, the portion of the vertical retorting chamber that was
5 used for oil shale combustion in the direct mode is now the region of the retort chamber into
6 which externally heated fuel gas is introduced. No combustion occurs within the retorting
7 chamber. That separate combustion process is typically fueled by commercial fuels (natural gas,
8 diesel, propane, etc.) that are often augmented with a portion of the fuel gas recovered from the
9 retorting operation. While they are very similar in operation, the direct and indirect mode Paraho
10 retorts offer sufficiently different operating conditions so as to change the composition of the
11 recovered crude shale oils and gases. Oil vapors and mists leave the direct mode retort at
12 approximately 140°F, while the vapors and gases in the indirect mode leave the retorting vessel
13 at 280°F and have as much as nine times higher heating values than gases and vapors recovered
14 from the direct mode retort (102 Btu/scf vs. 885 Btu/scf, or 908 kcal/m³ vs. 7,560 kcal/m³)
15 (EPA 1979). This is thought to be due principally to the fact that oil vapors and mists recovered
16 from the direct mode are “diluted” with combustion gases from the combustion of the spent shale
17 at the bottom portion of the retort. Characteristics of the recovered raw shale oil are somewhat
18 different for the direct and indirect mode retorts, but each has characteristics similar to shale oils
19 recovered from other retorts using similar shale heating mechanisms (direct vs. indirect). Retort
20 gases also differ from the two modes. Gases from indirect mode retorts have much lower levels
21 of CO₂ (due to the lack of dilution by gases from direct combustion) but generally higher levels
22 of H₂S, NH₃, and hydrogen, which are thought to be the result of the indirect mode retort having
23 much less of an oxidizing environment than the direct mode retort (EPA 1979). Finally, the
24 Paraho retort can also be operated in a direct/indirect hybrid mode.
25
26

27 **A.3.2.1.4 Lurgi-Ruhrgas Process.** The Lurgi-Ruhrgas technology was developed in
28 Germany for the production of pipeline-quality gas through the devolatilization of coal fines. The
29 technology has operated at commercial scales for the devolatilization of lignite fines, the
30 production of char fines for briquettes from sub-bituminous coal, and the cracking of naphtha
31 and crude oil to produce olefins. As with the Paraho process, the Lurgi-Ruhrgas process was
32 designed from its inception not only to retort kerogen but also to refine the resulting
33 hydrocarbons into saleable liquid and gaseous petroleum fractions.
34

35 In this process, crushed and sized (-0.25 in.) oil shale is fed through a feed hopper and
36 mixed with as much as six to eight times its volume of a mixture of hot spent shale and sand with
37 a nominal temperature of 1,166°F and conveyed up a lift pipe. This mixing raises the average
38 temperature of the raw shale to 986°F, a temperature sufficient to cause the evolution of gas,
39 shale oil vapor, and water vapor. The solids mixture is then delivered to a surge hopper to await
40 additional processing in which more residual oil components will be distilled off. The sand,
41 introduced as a heat carrier, is recovered and recycled. The mixture is then returned to the bottom
42 of the lift pipe and allowed to interact with hot combustion air at 752°F. The carbonaceous
43 fraction is burned as the mixture is raised pneumatically up the lift pipe and transferred to a
44 collection bin where the spent shale fines are separated from gases. The hydrocarbon gases and
45 oil vapors are processed through a series of scrubbers and coolers to eventually be recovered as
46 condensable liquids and gases. Because the shale particle size is initially so small, management

1 of fines is critical throughout the process and involves the use of sedimentation and centrifuging
2 as well as numerous cyclones and electrostatic precipitators.
3
4

5 **A.3.2.1.5 Superior Oil's Circular Grate Retorting Process.** One retort design
6 advanced by Superior Oil theoretically offers substantial environmental advantages over other
7 retorting processes. The design is a counterflow, gas-to-solid heat exchange process conducted in
8 an enclosed circular grate. Shale in a relatively wide range of sizes (0.25 to 4.0 in.) is added,
9 rotated to the first segment of the retort, and heated by a continuously circulating gas medium.
10 Volatilized oil (mists) mixes with the circulating gas and, together with water, is periodically
11 removed from the gas stream. The partially pyrolyzed shale rotates to the next segment of the
12 retort where it is partially oxidized to complete the kerogen pyrolysis and oil evolution. The
13 spent shale cools in the next segment of the grate as it yields heat to the circulating gas.
14 Additional heat is added to the first segment of the grate where initial pyrolysis of raw shale
15 takes place either through direct or indirect combustion of gases recovered from previous shale
16 retorting. This design has been used for many years in the processing of various ores, including
17 iron ores, and consequently has a relatively high reliability factor.
18

19 Only pilot-scale experiences exist for this retort when applied to oil shale. However,
20 numerous tests have identified critical control parameters and optimized operations resulting in
21 oil recovery yields greater than 98% Fisher assay results. From an environmental perspective, the
22 circular grate holds great promise, since it is essentially a sealed operation with hooded
23 enclosures above the grate, to capture hydrocarbon gases and oil mists, and water seals
24 (water troughs) below the grate, where spent shale is discharged. The water seals prevent gas and
25 mist leakage and also provide for the moistening of the spent shale that is necessary for its safe
26 handling and disposal.
27

28 Another unique aspect to the Superior circular grate retort is that it was designed to be
29 operated in conjunction with subsystems for the recovery of alumina and soda ash. Thus, this
30 design appears well suited for applications where saline deposits coexist with oil shale or are
31 present above or below the shale. In the Superior Oil circular grate process, spent shale is
32 delivered to subsystems that convert the saline minerals to saleable products. For example,
33 commonly encountered dawsonite [$\text{NaAl}(\text{OH})_2\text{CO}_3$] can be converted to alumina (aluminum
34 oxide [Al_2O_3] and soda ash [NaCO_3]). Further, conditions during kerogen retorting are favorable
35 for the simultaneous conversion of nahcolite (NaHCO_3) to soda ash, CO_2 , and water.
36

37 Technical advantages to this retort include the circumstance that the circulating shale is
38 independent of the circulated gas above it and that considerable experience with this type of
39 retort has identified and resolved the major operational problems. Although designed to operate
40 continuously, the unit can be quickly shut down and restarted. Temperature control is excellent,
41 resulting in high hydrocarbon recovery rates and relatively minor amounts of sintering of the
42 inorganic phase of the shale (Nowacki 1981).
43
44

45 **A.3.2.1.6 Alberta Taciuk Process.** The ATP is an AGR technology originally
46 researched and designed for the extraction of bitumen from tar sands in Canadian tar sands

1 deposits, some of the largest and richest deposits of their kind in the world. The ATP was
2 developed by UMATAC Industrial Processes, a division of UMA Engineering, Ltd., which
3 supplies the technology under license agreements.
4

5 The ATP Processor is the primary processing component of the technology and it works
6 in conjunction with a number of ancillary subsystems that, together, make up the ATP System.
7 As with many of the retorting technologies discussed above, the ATP System provides more than
8 simple retorting; the Processor, together with its subsystems, can provide primary upgrading of
9 the initial retort products, as well as capture and control of problematic by-products.¹⁰ The ATP
10 is a dry thermal process involving indirect heating of oil shale using countercurrent gas-solid
11 heat exchange as well as the generation of process heat by combustion of coke (carbon present
12 on retorted oil shale solids) in the combustion zone of the kiln. The ATP has been successfully
13 applied to retorting oil shale and has achieved improved yields of raw shale oil and combustible
14 gases over other retorting technologies developed and used specifically for the oil shale industry.
15 The ATP provides high heat-transfer efficiencies and integral combustion of coke for process
16 heat demands, which minimizes the amount of residual coke remaining on spent shale. This
17 combination minimizes CO₂ release per ton of shale processed and reduces the potential for
18 environmental contamination from improper spent shale disposal (DOE 2004).
19

20 A schematic flow diagram of the ATP System is shown in Figure A-3. A pictorial
21 representation of the functioning of the ATP Processor is shown in Figure A-4.
22

23 The ATP System also represents the likely direction of future AGR equipment in that it is
24 fitted with environmental control equipment to lessen the impact of air emissions and water
25 effluents typically resulting from retorting. The ATP technology has successfully operated at
26 semicommercial demonstration scale in Australia and is to be used commercially in China. There
27 is evidence to suggest that the ATP System will also continue to be applied to future oil shale
28 development.¹¹
29
30

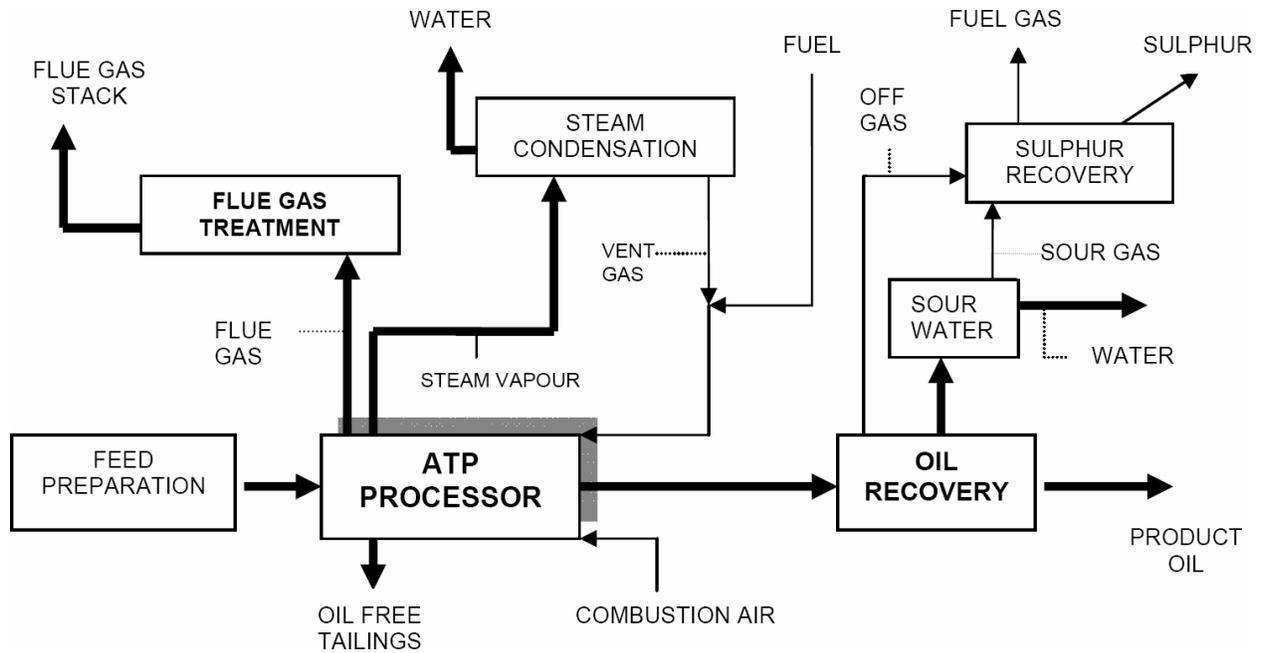
31 **A.3.2.2 In Situ Retorting** 32

33 First attempts at in situ formation heating were pursued with the intention of mobilizing
34 the kerogen to facilitate its movement through the formation for extraction by conventional
35 pumping/extraction devices. However, the objectives of in situ formation heating investigations
36 quickly expanded to include in situ pyrolysis of the kerogen.¹² Both TIS and MIS recovery
37 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.

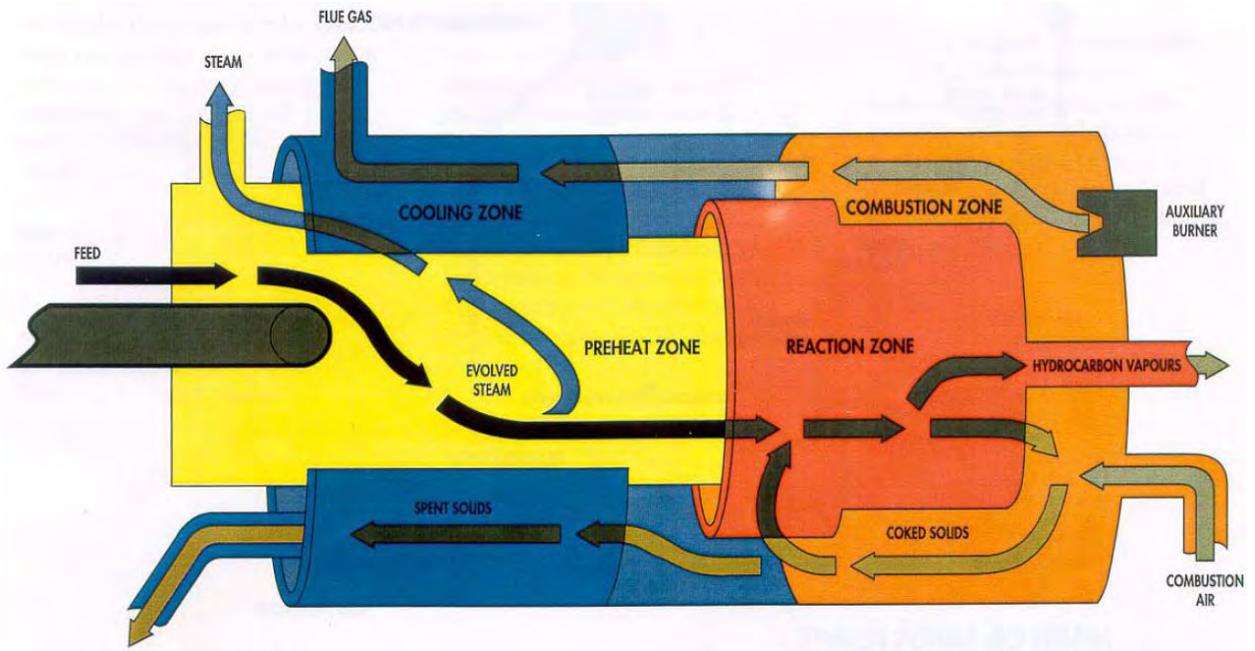
¹¹ The Oil Shale Exploration Company (OSEC) was one of the original applicants whose project was approved as part of the BLM's oil shale RD&D program. In 2011, the OSEC RD&D project was acquired by Enefit American Oil. OSEC had proposed to use a modified version of the ATP system for oil shale development in the Uinta Basin in Utah; Enefit may use a different version of the technology. Additional details of the Enefit/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).



1
2
3
4
5

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



6
7
8
9
10

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

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

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

23
24 Hydrocarbon products of successful in situ heating are similar in character to the products
25 recovered from AGRs: petroleum gases, hydrocarbon liquids, and char. Field experiences with
26 the first generation in situ retorts indicate that the petroleum gases tend to be of lesser quality
27 than gases recovered by AGRs.¹³ The condensable liquid fraction, however, generally tends to
28 be of better quality than the liquid hydrocarbon fractions recovered from AGRs with higher
29 degrees of cracking of the kerogen macromolecules and elimination of substantial portions of the
30 higher boiling fractions typically produced in AGRs. Overall yields with any in situ retorting
31 tend to be lower than yields from equal amounts of oil shale of equivalent richness processed
32 through AGR (EPRI 1981). Various explanations have been advanced for these observed
33 differences. Some of the loss of quality for recovered gases may be the dilution that results when
34 heat is introduced to the formation by injection of combustion gases and/or steam, by
35 advancement of a flame front as a result of combustion of some portion of the shale, or when
36 high-pressure gases are used to sweep retorting products from the formation to recovery wells.
37 The quality improvements for the liquid fraction may be due to the relatively slow and more
38 even heating that can be attained in a properly designed and executed in situ retorting process.
39 Such quality improvements also may be indicative of further refining of initial retorting products
40 when sweep gases such as natural gas or hydrogen are used. Finally, and importantly from an
41 environmental perspective, the char and the mineral fraction to which it is adsorbed are not
42 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.

1 collateral environmental impacts from solid by-product wastes. Limited evidence collected by
2 the EPA suggests that groundwater quality impacts may still result from in situ spent shale.
3

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

- 12
- 13 • Simplified material handling requirements (only the retorted organic fraction,
14 roughly less than 15% by weight of the parent oil shale, would need to be
15 recovered from the formation);
- 16
- 17 • Greater portions of the deposit would be accessible for economical kerogen
18 recovery (albeit perhaps at a lower overall recovery efficiency);
- 19
- 20 • Spent shale from conventional retorting, a significant solid waste issue, would
21 be virtually eliminated;
- 22
- 23 • Overall energy efficiencies may increase over conventional retrieval and AGR
24 methods;
- 25
- 26 • Air pollution potential would be significantly reduced;
- 27
- 28 • Noise pollution would be severely reduced;
- 29
- 30 • Impacts on ecosystems and fugitive dust potential would be reduced because
31 of the smaller aerial extent of surface industrial activities and the reduced land
32 area required for material stockpiles and solid waste disposal; and
- 33
- 34 • Surface water quality impacts would be reduced because of the reduced size
35 of land disposal areas and the reduced potential for stormwater pollution from
36 interim material and waste pile runoff.
- 37

38 In situ retorting also has some potential disadvantages. Intuitively, the overall success of
39 any in situ retorting technology results from its ability to distribute heat evenly throughout the
40 formation. Indiscriminate formation heating that allows portions of the formation to reach
41 1,100°F can result in technological problems, as well as the thermal decomposition of mineral
42 carbonates and the formation and release of CO₂. From an operational standpoint, such
43 decompositions are endothermic and will result in the energy demands of such uncontrolled in
44 situ retorting quickly becoming insurmountable. As noted above, environmental consequences of
45 carbonate decomposition during in situ retorting can be expected to be mitigated to a large extent
46 by the natural CO₂ sequestrations that can also be anticipated. Nevertheless, the lack of precise

1 heat control will devastate both the yields and the quality of recovered hydrocarbons and must be
2 avoided. However, in situ retorting with good thermodynamic controls can produce pyrolysis
3 products of equal or even greater quality than AGR.
4

5 Another potential disadvantage to in situ retorting involves the time that it takes to heat
6 substantial masses of formation materials to retorting temperature (on the order of months or
7 years) and the energy costs over that period. Field experiences are limited, and, because every
8 formation accepts heat differently, it is difficult to define a universal time line or perform
9 precise, reliable energy balances except on a site-specific basis.
10

11 Other largely unanswered questions involve long-term impacts from retorted segments of
12 oil shale formations. Questions regarding long-term impacts include:
13

- 14 • Will vacated pore spaces need to be filled to prevent surface subsidence?
- 15
- 16 • Will groundwater flow patterns change significantly?
- 17
- 18 • Will groundwater interactions with retorted shale minerals facilitate the
19 leaching of heavy metals or other contaminants?
- 20
- 21 • Will water produced from in situ combustion become a conduit for delivery of
22 contaminants to existing groundwater aquifers?
- 23
- 24 • Will CO₂ produced in situ be safely sequestered indefinitely within the
25 formation?
26

27 While conceptual designs for in situ retorting are numerous, only limited field activities
28 have been pursued, mostly undertaken as proof-of-concept exercises, but, in a few instances,
29 with the intent of advancing the practical development and application of specific in situ retort
30 designs. Field data on both the short- and long-term impacts of in situ retorting are therefore
31 limited. Independent investigations were conducted as early as 1953. Government-sponsored
32 research began in the 1960s. The following sections provide brief descriptions of the early
33 research and a more extensive description of only the most prominent in situ retorting
34 technology. Also included are brief descriptions of RD&D projects that have been recently
35 proposed and approved by the BLM for further research and that also involve some form of
36 in situ retorting.
37
38

39 **A.3.2.2.1 Early In Situ Retorting Experiments.** Lee (1991) has provided the following
40 brief summaries of some of the earliest research into in situ technologies:
41

- 42 • ***Sinclair Oil and Gas.*** Sinclair's experiments investigated one of the earliest
43 uses of high-pressure air injected into the formation to sweep retort products
44 to recovery wells.
45

- 1 • **Equity Oil Company.** Equity’s process used hot natural gas to both retort the
2 shale and sweep the retort products to recovery wells.
3
- 4 • **Laramie Energy Technology Center (LETC).** LETC sponsored some early
5 research into in situ retorting in the early 1960s at Rock Springs, Wyoming.
6 The purposes of this research were twofold: (1) establish the best mechanisms
7 for enhancing the fracturing of the formation to increase its permeability, and
8 (2) investigate the process by which in situ combustion of shale and the
9 subsequent movement of a heat front through the formation could be made
10 self-sustaining.
11
- 12 • **Dow Chemical.** Dow Chemical’s research was conducted on eastern
13 United States shale in Michigan, but much of the experience is transferable to
14 western shales. Dow’s experiment was one of the earliest examples of TIS. It
15 used explosives to enhance fracturing and electrical resistance heaters
16 combined with propane-fired burners to effect in situ retorting.
17
- 18 • **Geokinetics, Inc.** The Geokinetics process was one of the earliest uses of
19 horizontally oriented retort voids in an MIS process. This DOE-sponsored
20 research occurred near Grand Junction, Colorado, in the Parachute Member of
21 the Green River Formation and also in the Mahogany Zone. Importantly, this
22 research proved the value of horizontal retort chambers in relatively thin shale
23 deposits.
24
25

26 **A.3.2.2.2 The Occidental Oil Shale MIS Retort Technology.** OOSI conducted much
27 of the pioneering investigations into in situ retorting under the auspices of a DOE contract,
28 issuing its final report in January 1984. Although the operation was under the control of OOSI,
29 personnel from DOE’s Sandia National Laboratories provided consultation services throughout
30 the project and were instrumental in development of the final report (Stevens et al. 1984). The
31 project was conducted in two phases near Logan’s Wash near Debeque, Colorado, and represents
32 one of the most extensive research ventures into MIS vertical in situ retorting technology.
33

34 The OOSI experiment was conducted in two phases and was intended to provide
35 demonstrations of mining, rubblizing, ignition, and simultaneous processing of commercial-sized
36 MIS retorts. Although the primary thrust of the research involved the development of design and
37 operating parameters for the MIS in situ retort, support systems, including surface processing of
38 retort products, were also investigated.
39

40 The retorting technology involved creating a void in the oil shale formation using
41 conventional underground mining techniques.¹⁴ Explosives (ammonium nitrate and fuel oil
42 [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.

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

15
16 Ultimately, oil recovery was equivalent to 70% of the yield predicted through Fisher
17 assay. Design of the experiment was directed toward potential future commercial applications so
18 numerous that such in situ retorts were operated simultaneously to demonstrate the practicability
19 of an approach that would likely have been desirable in commercial development ventures.
20 Conceptual views of the OOSI in situ retort and the expected movement of the heat front through
21 the formation are displayed in Figures A-5 and A-6, respectively.

22
23 From a technological perspective, the OOSI in situ retorting experiment was a success.
24 Recovered crude shale oil has a specific gravity of 0.904 (American Petroleum Institute [API]
25 gravity of 25°¹⁸), a pour point of 70°F, a sulfur content of 0.71% (by weight), and a nitrogen
26 content of 1.50% (by weight). OOSI believes that crude shale oil meeting those specifications
27 would be available for use as a boiler fuel without further processing or would certainly
28 constitute acceptable refinery feedstock for additional refining to other conventional fuels.

29
30 From an environmental perspective, many questions were raised regarding the type and
31 scale of environmental impacts that would result from either the initial in situ retorting or from
32 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 rubbleized 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.

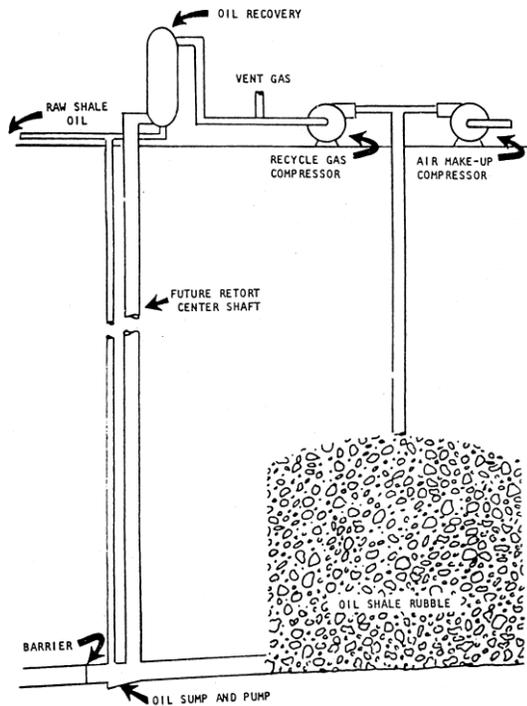


FIGURE A-5 Conceptual Design of the Occidental Oil Shale, Inc., MIS Retorting Process (Source: EPA 1979)

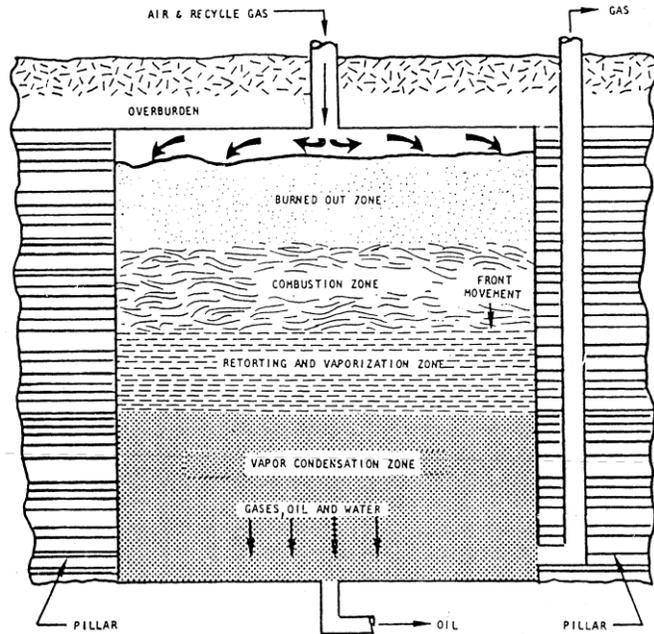


FIGURE A-6 Conceptual View of the Downward Movement of the Heat Front through the Formation in the Occidental Oil Shale, Inc., Vertical In Situ Retort (Source: EPA 1979)

1
2
3 questions remain unanswered. As part of its development plan, OOSI identified as many as
4 48 separate activities associated with this technology for which there could be an environmental
5 impact. Environmental monitoring throughout the project and beyond was scheduled to verify
6 and quantify those impacts. However, the magnitudes of many of OOSI's anticipated impacts are
7 disputed by the EPA.
8

9 First, the EPA disputes the OOSI claim of the magnitude of nitrogen oxides (NO_x)
10 emissions that would result from combustion of the recovered crude shale oil in an industrial
11 boiler, believing that the amount would be much greater than that claimed. Second, it has not
12 been reliably demonstrated that all of the CO_2 generated during the retorting (from combustion
13 sources as well as carbonate decomposition) would be successfully sequestered in the formation
14 indefinitely. Thirdly, major water management problems exist. It was estimated that the volume
15 of retort water created during retorting plus the amount of water used for surface processing
16 (upgrading) of retort products and for fugitive dust control throughout the operational area is
17 essentially equivalent to the volume of crude shale oil produced. Thus, a substantial volume of
18 water may require treatment before discharge or recycling. Further, groundwater monitoring data
19 appear to indicate that groundwater contamination had occurred, both during and after
20 completion of retorting. The extent to which the retort water contains contaminants that would
21 require proper treatment could not be reliably predicted, and it is not clear whether any or all of
22 this water could be recycled for use in future processing.
23

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

- 3
- 4 • Total alkalinity, NH₃, phenols, dissolved organic carbon, thiosulfate, and
5 thiocyanide concentrations are significantly higher in retort water (i.e., waters
6 recovered from retorts during operation) than in natural water;
- 7
- 8 • Aluminum, magnesium, and calcium concentrations are lower in retort water
9 than in natural water;
- 10
- 11 • Monitoring data from wells near the retort operations showed no discernable
12 trends that could be interpreted as contamination from the retorts; however,
- 13
- 14 • Trends over time indicate that concentrations of constituents thought to be
15 leaching from the retired retorted areas initially increase significantly from
16 natural waters but also quickly equilibrated (in a matter of 2 years or less) to
17 levels approximating the concentrations in natural waters without any
18 intervention or remediation, suggesting that most leaching occurs from the
19 initial flushing of retorted zones by infiltrating groundwater, but also that the
20 amounts of leachable materials remaining in retorted zones appear to be
21 limited.
- 22
- 23

24 **A.3.3 Upgrading Oil Shale**

25

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

33

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

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

4
5 Upgrading crude shale oil at the mine site might consist of all of the above steps,
6 although hydrogen-addition reactions generally predominate, and reactions to produce specialty
7 chemicals are not likely to occur at all. Upgrading is typically directed only at the gaseous and
8 liquid fractions of the retorting products and is rarely applied to the solid char that remains with
9 the inorganic fraction of the oil shale, although coking of that solid fraction is possible. The most
10 likely end products will be refinery feedstocks suitable for the production of middle distillates
11 (kerosene, diesel fuel, jet fuel, No. 2 fuel oil), although lighter weight fuel components such as
12 gasolines can also be produced. In general, hydrotreating followed by hydrocracking will
13 produce jet fuel feedstocks, hydrotreating followed by fluid catalytic cracking is performed for
14 production of gasoline feedstocks, and coking followed by hydrotreating is performed with the
15 intention of producing diesel fuel feedstocks (Speight 1997).

16
17 Similar to the preliminary steps taken at refineries, prior to or coincident with crude shale
18 oil upgrading reactions, there are also activities to separate water from both the gas and liquid
19 fractions, to separate oily mists from the gaseous fraction, and to separate and further treat gases
20 evolved during retorting to remove impurities and entrained solids and improve their combustion
21 quality.¹⁹ Actions to remove heavy metals and inorganic impurities from crude shale oils also
22 take place.

23
24 Upgrading activities are dictated by factors such as the initial composition of the oil
25 shale, the compositions of retorting products,²⁰ the composition and quality of desired petroleum
26 feedstocks or petroleum end products of market quality, and the business decision to develop
27 other by-products such as sulfur and NH₃ into saleable products.²¹ Product variety and quality
28 issues aside, there are other logistical factors that determine the extent to which upgrading
29 activities are conducted at the mine site. Most prominent among these factors is the ready
30 availability of electric power and process water. In especially remote locations, factors such as
31 these represent the most significant parameters for mine site upgrading decisions.

32
33 The initial composition of the crude shale oil produced in the retorting step is the primary
34 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.

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

8
9 Sulfur, also a poison to refinery catalysts, is typically present in much lower proportions
10 as organic sulfides and sulfates. With respect to sulfur, crude shale oil compares favorably with
11 most low-sulfur crude oils, which are preferred feedstocks for low-sulfur fuels that are often
12 required by local air pollution regulations. Hydrotreating to the extent necessary to convert
13 nitrogen compounds to NH₃ is sufficient in most instances to simultaneously convert sulfur to
14 H₂S. Crude shale oil additionally contains much higher amounts of organometallic compounds
15 than conventional crude oils. The presence of these organometallic compounds complicates the
16 mine site upgrading, since they can readily foul the catalysts used in hydrotreating, causing
17 interruptions in production and increased volumes of solid wastes requiring disposal, sometimes
18 even requiring specialized disposal as hazardous wastes because of the presence of spoiled
19 heavy-metal catalysts.

20
21 Desired end products for mine site upgrading are typically limited to mixtures of organic
22 compounds that are acceptable for use as conventional refinery feedstock; however, it is possible
23 to produce feedstocks that are of higher quality and value to refineries than even crude oils
24 having the most desirable properties. Since crude shale oils are typically more viscous than
25 conventional crude oils, their yields of lighter distillate fractions such as gasolines, kerosene, jet
26 fuel, and diesel fuel are typically low. However, additional hydrotreating can markedly increase
27 the typical yields of these distillate fractions.

28
29 Given the high capital costs involved in constructing and operating more sophisticated
30 refining operations at remote mine sites, there is little incentive for mine operators to duplicate
31 existing refinery capabilities, and most oil shale development business models will likely include
32 only the upgrading that is minimally necessary for the end products to be acceptable to
33 conventional refineries and capable of being transported to those refineries by existing
34 conveyance technologies (i.e., sufficiently improved API gravities and pour points). Such a
35 business model was endorsed by the Committee on Production Technologies for Liquid
36 Transportation Fuels of the National Research Council in 1990 and is believed to still be
37 applicable today (National Research Council 1990).

38
39 All of the factors controlling upgrading are very site- and project-specific. At the PEIS
40 level, it is not possible to precisely describe all of the actions that may be undertaken for the
41 purposes of upgrading retorting products; however, a general overview of the nature of those
42 reactions is provided below. An example of an explicitly defined upgrading scheme is provided
43 in the BLM's *Final Environmental Impact Statement for the Proposed Development of Oil Shale*
44 *Resources by the Colony Development Operation in Colorado, Volume I* (BLM 1977).

45

1 Upgrading is designed to increase the relative proportion of saturated hydrocarbons over
2 unsaturated hydrocarbons in the crude shale oil recovered from retorting and to eliminate the
3 other compounds present that can interfere with further refining of the crude shale oil into
4 conventional middle distillate fuels (primarily, compounds containing nitrogen or sulfur atoms).
5 Hydrogen at high temperatures and pressures is used to create a reducing atmosphere in which
6 olefinic or aromatic hydrocarbons are converted to alkanes (or saturates), and organic
7 compounds containing sulfur or nitrogen are destroyed with the sulfur and nitrogen being
8 converted to H₂S and NH₃, respectively, which are then captured and removed. As upgrading
9 converts crude shale oil to syncrude, the physical properties change significantly. As a practical
10 matter, the pour point and API gravity of the liquid fraction are substantially increased, making
11 syncrude much easier to handle and transport than crude shale oil (typically another stated goal
12 of mine site upgrading). Gaseous components are converted to fuel gas, LPG, and butanes,²² all
13 becoming available for use as fuels to support further oil shale processing or as marketable
14 materials for sale at the wholesale or retail level. Most probably, gases such as propane and
15 propylene would be stored and receive an appropriate odorant gas (e.g., methyl mercaptan) for
16 eventual sale as LPG, while any hydrogen produced as well as the butane/butylene fraction are
17 more likely to be returned to the retorting process and consumed as supplemental fuel.
18
19

20 **A.4 SPENT SHALE MANAGEMENT**

21
22 An important component of surface mining and underground mining projects is spent
23 shale management. Either surface mining or underground mining projects may opt to dispose of
24 spent shale in surface impoundments or as fill in graded areas; for surface mining projects, it
25 may be disposed of in previously mined areas. Disadvantages of surface disposal include the use
26 of large land areas; labor-intensive requirements to revegetate the disposal area; dust-control
27 prior to revegetation; and potential impacts on surface water, particularly salinity, from runoff
28 water containing residual hydrocarbons, salts, and trace metals from the spent shale.
29

30 While disposal of spent shale back into the underground oil shale mine or a preexisting
31 mine appears initially attractive, various logistical issues may prevent or limit such disposals as
32 well as cause potential problems unique to that disposal technique. For example, mine
33 development design may prevent convenient access to retired portions while the mine is still
34 active. Also, while the potential for leaching of toxic constituents from the spent shale as a result
35 of precipitation or run-on surface water interactions is effectively eliminated, leaching as a result
36 of interaction of groundwater can still be anticipated.²³
37

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.

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

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

13
14 It has been reported in the literature that as much as 30% expansion in volume can occur
15 in spent shales over the parent raw shale (DOE 1988; Argonne 1990). The exact reasons for this
16 phenomenon are not fully understood. Certainly, some density changes could be expected after
17 removal of the organic fractions. It may also be that CO₂ is being released from decomposing
18 carbonate minerals, and the gas expands the mineral structure as it escapes.

19
20 Density changes can be expected to be slightly different for each specific retorting
21 technology, but in all cases, densities of spent shale have decreased over the density of the parent
22 oil shale. A plant producing 50,000 bbl/day from 30 gal/ton oil shale using surface or subsurface
23 mining and AGR may need to dispose of as much as approximately 450 million ft³ of spent shale
24 each year (DOE 1988). Regardless of the degree of compaction that can be accomplished during
25 placement of spent shale, and assuming that the spent shale disposal strategy involves placement
26

27
28 **TABLE A-5 Structural Properties of Compacted Paraho AGR**
29 **Spent Shale**

Parameter	Ranges of Values Measured
Compaction (dry density)	1,400–1,600 kg/m ³ (87–106 lb/ft ³)
Permeability	1 × 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.

1 in retired mine areas to reestablish the original grades and topographies of those areas, as much
2 as 30% of the volume of spent shale would be left once those original grades and topographies
3 were reestablished and would need to be disposed of in virgin areas.
4

5 Field data evaluating the leachate character of spent shale have been collected by the
6 EPA and others. Although the data are limited, there appears to be a clear indication that
7 subjecting oil shale to retorting conditions can result in the mobilization of various ionic
8 constituents contained in the mineral portion of the oil shale. Polar organic compounds with
9 moderate to high water solubility formed during retorting and not successfully separated from
10 the spent shale can also appear in spent shale leachates. Tables A-6 and A-7 show typical
11 expected ranges of leachate constituents for spent shale from both in situ and aboveground
12 retorting.
13

14 Independent leachate studies have also been carried out on both spent shale disposal piles
15 and piles of raw shale, with emphasis on the potential leachability of arsenic, selenium,
16 molybdenum, boron, and fluorine (as the fluoride ion), all species that are relatively toxic to
17 plants and can be expected to exist as soluble anions under the pH conditions normally
18 encountered in waters interacting with spent shale disposal piles or raw shale stockpiles
19 (i.e., $8 \leq \text{pH} \leq 12$) (Stollenwerk and Runnells 1981). The results of these studies supported the
20 predictions regarding the character of typical leachates from spent shale piles presented in
21 Table A-7.
22

23 Another study performed at the Anvil Points Oil Shale Facility in Rifle, Colorado,
24 appeared to identify species that are unique to spent shale leachates and thus possibly useful for
25 monitoring the movements of leachate from spent shale disposal areas (Riley et al. 1981). Soil
26 extracts, surface waters, and groundwaters were analyzed for the presence of water-soluble
27 organic compounds in a drainage area adjacent to a spent shale disposal pile. The C3–C6
28 alkyipyridines²⁵ were identified in alluvial groundwater samples and in surface waters below a
29 seep and in moist subsoils adjacent to the alluvial sampling well. Extracts of raw shale, crude
30 shale oil, and crude oil from Prudhoe Bay, Alaska, showed no alkyipyridines, however,
31 suggesting that alkyipyridines may be produced during oil shale retorting and become unique
32 constituents of the char on the spent shale. Thus, alkyipyridines may serve as excellent agents for
33 monitoring leachate movements from spent shale piles.
34
35

36 **A.5 ONGOING AND EXPECTED FUTURE OIL SHALE DEVELOPMENT** 37 **TECHNOLOGIES** 38

39 Limited research into future oil shale development technologies is ongoing, but more is
40 currently being planned. The clear trend established near the end of the last period of major oil
41 shale development activities involved the move to in situ technologies.
42

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 [$\text{C}_n\text{H}_{(n+1)}$].

1
2**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).

3
4

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 MoO₄⁻².

^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.

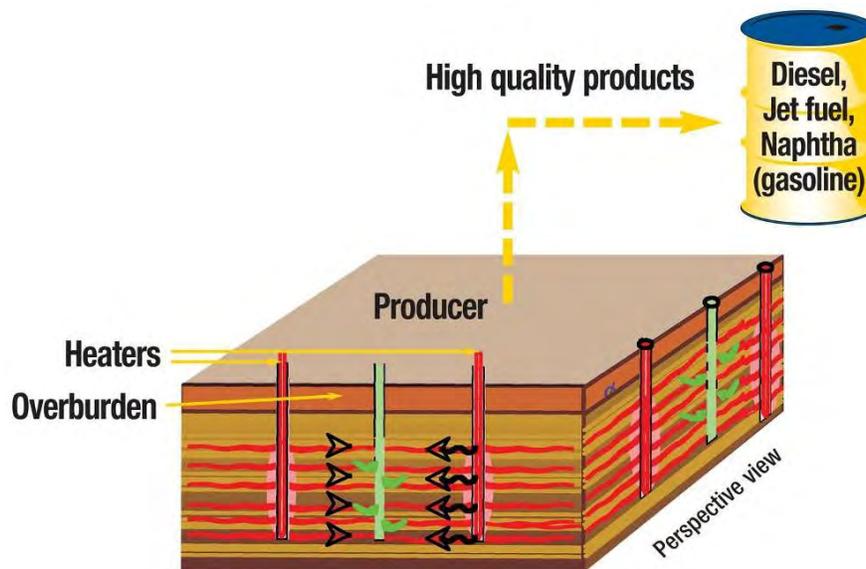
1 recovered using conventional extraction technologies and that will require very little additional
 2 processing or modification before being delivered to conventional refineries. An initial review of
 3 this project was provided by DOE (2004a).

4
 5 An artist's conceptual drawing of the ICP is shown in Figure A-7. Figure A-8 is a
 6 photograph of the Shell Mahogany Research Project site.

7
 8 Initial results are very promising. Shell's fact sheet (Shell 2006) characterizes the
 9 attributes of this technology in the following manner:

- 10 • The process is more environmentally friendly than previous oil shale efforts
- 11 that were based on mining and retorting.
- 12
- 13 • ICP has the potential to double the recovery efficiency, as it enables access to
- 14 much deeper and thicker oil shale reserves.
- 15
- 16 • ICP can potentially generate transportation fuel products that require
- 17 considerably less processing.
- 18

19
 20 Early research data appear to support these claims. Recovered products have included gases
 21 (hydrogen, natural gas, other combustible gases); (approximately one-third by weight of the total
 22 amount recovered) as well as light oils of relatively high quality (typically API 36°);
 23 approximately two-thirds by weight. Recovery rates as high as 62% (of recoverable oil) have
 24 been observed. Extrapolations from the test scale suggest potential yields (from oil shale deposits
 25 of equal richness) of as much as 1 million bbl/acre (i.e., heating of 1 acre of aerial extent of the
 26
 27



28
 29 **FIGURE A-7 Cross Section of Shell's Patented ICP Technology**
 30 **(Courtesy: Shell Exploration & Production; reprinted with**
 31 **permission)**



1
2 **FIGURE A-8 Shell's Field Research in Rio Blanco County, Colorado (Courtesy: Shell**
3 **Exploration & Production; reprinted with permission.)**
4
5

6 formation throughout the entire depth of the formation present within that 1-acre footprint)
7 (Boyd 2006).
8

9 Shell is currently preparing to integrate the research it has been conducting on the
10 individual aspects of this technology (e.g., developing and maintaining a freeze wall, optimizing
11 electric heater technology and rates of formation heating, optimizing product recovery
12 techniques) into a larger-scale demonstration project under the auspices of an RD&D lease
13 recently issued by the BLM. In 1996, Shell carried out a small field test on its Mahogany
14 property in Rio Blanco County, Colorado, by using an in-ground heating process to recover oil
15 and gas from the shale formation. Since then, Shell has carried out four additional field studies
16 on private land near the towns of Rangely, Rifle, and Meeker, Colorado. The most recent test has
17 produced 1,500 bbl of light oil plus associated gas from a relatively small plot. Shell's research is
18 continuing, and Shell has nominated three separate projects under the BLM's oil shale RD&D
19 program to further evaluate its process on public lands.
20
21

22 **A.5.2 Oil Tech, Inc., AGR Research** 23

24 Oil Tech, Inc., a small independent corporation, has been conducting research into
25 aboveground retorting using electric resistance heating. The company maintains a small research
26 site on approximately 2,600 acres of state-owned land approximately 20 mi east-northeast of
27 Bonanza, Utah. This area is also underlain with Green River Formation shale at approximately a
28 1,000-ft depth but has never been mined. Approximately 70,000 tons of Mahogany Ridge oil
29 shale that had been previously mined from the U-a research tract more than 20 years ago has
30 provided the feedstock for this AGR research and development effort to date. Truckload
31 quantities of run-of-mine shale are delivered periodically to the research site and stockpiled
32 there. The shale is crushed on-site to nominal 1/2-minus size before being introduced by a

1 conveyor system to the vertical AGR. The AGR is of modular design, composed of a series of
2 individual heating chambers, interconnected and stacked one upon the other, into which shale is
3 loaded from the top. Heating rods extend into the centers of each of these chambers, transmitting
4 heat to the shale in each chamber. Temperatures in each chamber are monitored and controlled
5 by thermocouples. The temperature profile increases from top to bottom of the retort,
6 culminating in the lowest heating chamber attaining a temperature of 1,000°F. An induced draft
7 fan exerts a slight vacuum simultaneously on all of the chambers through a common plenum,
8 providing the principal means of extracting and collecting the gases and volatilized organic
9 products of kerogen pyrolysis released from the shale by the process of fractional vaporization.
10 Pyrolysis products are collected, filtered, and condensed. Spent shale is dumped by gravity from
11 the bottom chamber, allowed to cool, and stockpiled for disposal. Shale moves from the top of
12 the retort to the lowest heating chamber by gravity displacement. The design basis for this retort
13 is 500 tons/h of shale input, resulting in a shale processing rate of approximately 24,000 yd³/day.
14

15 The particular advantages of this retort include the following:

- 16 • The modular design allows for relative portability and adaptability.
- 17
- 18 • The process requires no water yet produces approximately 200 lb of water
19 (kerogen pyrolysis as well as free water present in the feedstock) for every ton
20 of shale retorted.
- 21
- 22 • Heavily insulated enclosure and heating chambers maximize heating
23 efficiency.
- 24
- 25 • Product separation is easily accomplished.
- 26
- 27 • Product quality is such that little additional upgrading is required.
- 28
- 29

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

- 33 • Mass balances are incomplete to this point.
- 34
- 35 • Production curves and reaction kinetics have not yet been calculated.
- 36
- 37 • The fates of sulfur and nitrogen in the kerogen have not yet been investigated.
- 38
- 39 • Yields have not been precisely calculated; however, spent shale averages 10%
40 residual carbon.
- 41
- 42 • Leachability, weathering characteristics, and structural features of the spent
43 shale have not been fully investigated.
- 44
- 45

- 1 • No data have been collected regarding the extent to which carbonates are
2 decomposing in the lower (hottest) sections of the retort; however, the acidic
3 character of the pyrolysis water recovered suggests some carbonate
4 decompositions may be occurring.
5
- 6 • Relationships between operating parameters and yield have not been fully
7 explored.
8

9 The next phase of the research was scheduled to occur in the spring of 2006 and was to
10 involve a 30-day continuous operation of the retort using the Mahogany Ridge shale that is still
11 at the research site. Over this period, additional data will be collected that will be essential for
12 optimizing operating parameters for the retort, establishing reaction kinetics and
13 thermodynamics to optimize yields, and more precisely evaluating the environmental impacts of
14 the operation, including disposal of spent shale.
15

16 As an aside, company representatives have indicated their intent to investigate the
17 possible use of abandoned gilsonite mines for disposal of spent shale and have calculated as
18 much as 5 million ft³ of disposal space to be available in abandoned mines in the immediate area
19 that are located on private lands.²⁷
20
21

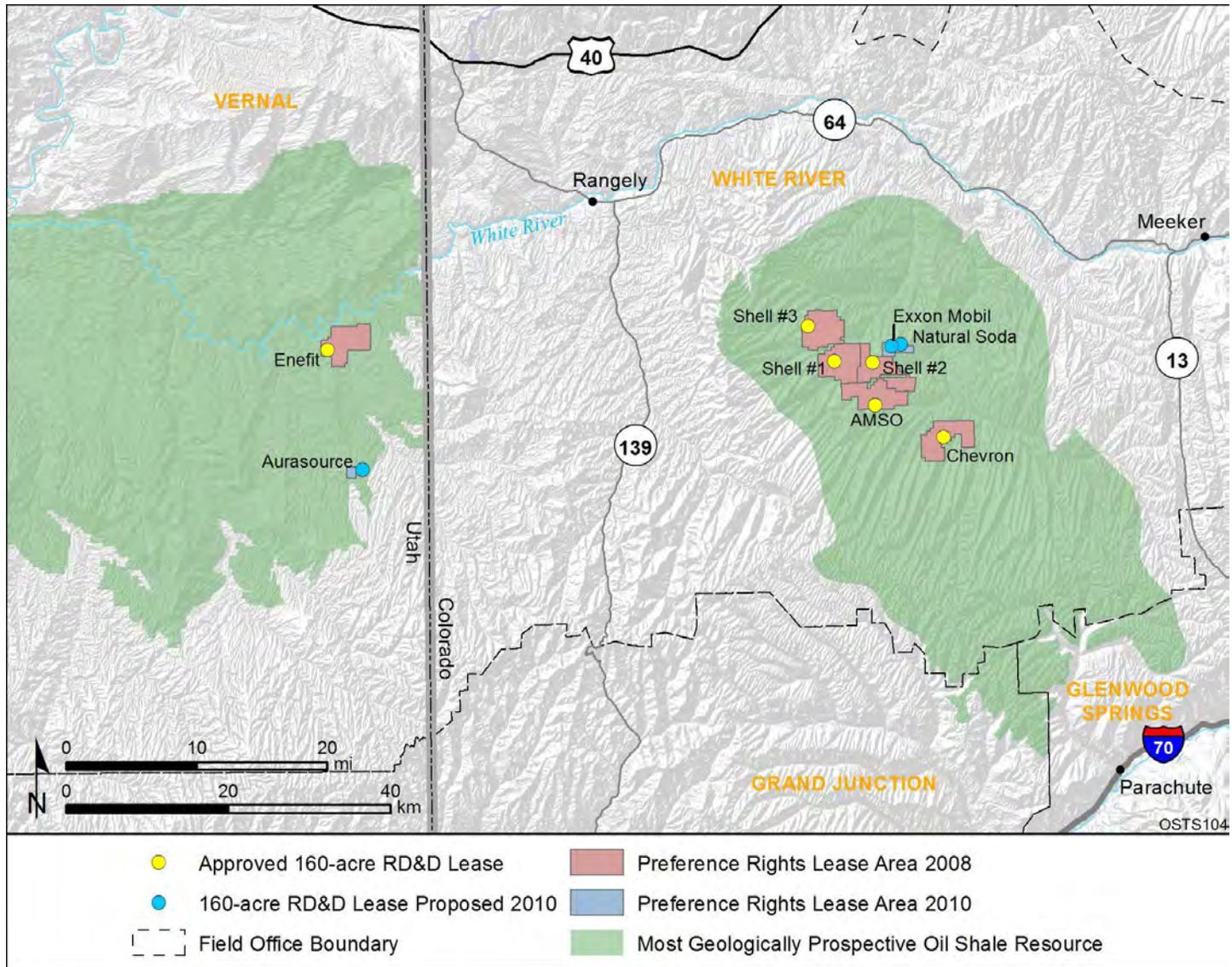
22 **A.5.3 Current and Proposed RD&D Projects on BLM-Administered Lands**

23

24 On June 9, 2005, pursuant to its authority to lease federal lands for oil shale development
25 under Section 21 of the Mineral Leasing Act (*United States Code*, Title 30, Section 241
26 [30 USC 241]), the BLM published a notice in the *Federal Register* (Volume 70, page 33753
27 [70 FR 33753]) announcing a program wherein companies or individuals could submit proposals
28 to lease 160-acre tracts of BLM-managed land for a period of up to 10 years for the purpose of
29 RD&D of oil shale development technologies. Potential lessees were required to submit a
30 detailed plan of operation development that addressed their proposed development scenario,
31 including their approaches for complying with applicable laws and regulations and
32 environmental protection.
33

34 The BLM reviewed each of the proposals that were submitted and selected six to receive
35 further consideration. Upon successful completion of required environmental assessments (EAs),
36 each of the six applicants was awarded a 160-acre lease on which to conduct RD&D of oil shale
37 development technology for a period of up to 10 years, with the potential to extend the lease for
38 another 5 years. Assuming that the RD&D efforts are successful, each RD&D leaseholder will be
39 given the opportunity to exercise a preference right lease, expanding the areal extent of its BLM
40 lease to a maximum of 5,120 acres, thus facilitating transition from research-scale to
41 commercial-scale operations. In 2010, the BLM issued a second-round solicitation for RD&D

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.



1

2

3

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

1 proposals and received three new proposals, which are currently being evaluated. The second-
2 round proposals were limited to a 160-acre lease, with potential expansion under a preference
3 right lease to a maximum area of 640 acres. Figure A-9 shows the locations of the six current and
4 three proposed RD&D tracts and the associated preference right lease areas. The following
5 sections provide overviews of the six current projects on the basis of information published in the
6 EAs (BLM 2006a–c, 2007) and of two of the three proposed projects, based on information
7 provided in plans of operation (ExxonMobil 2011; Natural Soda Holdings 2011). Table A-8 lists
8 the hazardous materials, hazardous wastes, and wastewater streams associated with these
9 projects.²⁸

10 11 12 **A.5.3.1 Chevron U.S.A., Inc. (Chevron)**

13
14 The Chevron RD&D project is located in the Piceance Basin of Colorado; information
15 presented here regarding this project is taken from the EA of the proposed activities
16 (BLM 2006a). Chevron employs an in situ process for shale oil recovery and production that is
17 facilitated by applying drilling, fracturing, and in situ heating technologies. This methodology
18 entails drilling wells into the oil shale formation and applying a series of horizontal fracturing
19 technologies. The process generates hot gases via the in situ combustion of the remaining
20 organic matter in previously heated and depleted zones. These hot gases are then introduced into
21 the fractured zone to decompose the kerogen into producible hydrocarbons.

22
23 The location of the 160-acre lease parcel granted for Chevron's R&D activities is shown
24 in Figure A-9. Access to the proposed project area is via Colorado State Highways 13 and/or 64
25 and County Roads 5 (Piceance Creek), 26, 29, and 69. The lease parcel is situated adjacent to
26 County Road 69 on Hunter Ridge at an elevation of 6,560 to 6,660 ft.

27
28 Chevron's methodology for shale oil recovery applies to an oil shale deposit that is
29 approximately 200 ft thick. This methodology entails drilling wells into the oil shale formation
30 and applying a series of controlled horizontal fractures within the target interval induced by
31 injecting CO₂ gas into discrete areas of the target interval to effectively rubblize the production
32 zone in a horizontal plane. If necessary, propellants and/or explosives might be directed into the
33 specific horizontally and vertically limited area to facilitate further rubblization of the production
34 zone in order to prepare it for heating and in-situ combustion.

35
36 The seven phases of the process, as described in the EA for the project (BLM 2006a) are
37 summarized below; some of the activities have since been completed:

- 38
39 • *Phase 1.* A core would be extracted for use in developing a more
40 comprehensive site-specific understanding of the geology, mineralogy,
41 hydrogeology, and geophysical properties of the formation.
42

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

1 **TABLE A-8 Hazardous Materials and Wastes, Other Wastes, and Wastewater Associated with the**
 2 **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 the Enefit, formerly 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 Enefit 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 (Enefit 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).

- 1 • *Phase 2.* Activity would be directed at identifying and avoiding the existing
2 natural fracture network.
3
- 4 • *Phase 3.* One or more additional test wells would be drilled to confirm and
5 verify the extent of the fracture network.
6
- 7 • *Phase 4.* Additional fracturing of the shale would be facilitated by subjecting
8 the formation to thermal cycles using hot CO₂ gas brought in by CO₂ tanker
9 trucks.
10
- 11 • *Phase 5.* The formation heating process would be initiated by circulating
12 pressurized heated gas through the fractured interval of the formation.
13
- 14 • *Phase 6.* This phase would involve the decomposition of the kerogen and
15 production of shale oil. Before the formation reached the kerogen
16 decomposition temperature, equipment would be installed to collect and
17 process the produced water, gas, and shale oil.
18
- 19 • *Phase 7.* After the recoverable kerogen was extracted from the initial wells,
20 the proposed RD&D program would include integrating the heating process
21 by drilling a new well pattern adjacent to the first and repeating the fracture
22 process. Hot gases from in situ combustion of the residual organic material
23 remaining in the oil shale would be used to heat the newly fractured zone.
24

25 Chevron believes that these fractured zones would have a predominantly horizontal
26 component that would allow for the maintenance of barriers between the production zone and the
27 upper and lower water-bearing units. The detection and avoidance of the natural vertical
28 fractures within the formation is a key component of the proposed technology.
29

30
31 **A.5.3.1.1 Groundwater and Surface Water Management.** As many as 20 groundwater
32 monitoring wells will be drilled into both the upper and lower water-bearing units as part of a
33 comprehensive groundwater monitoring program incorporated into the design of the proposed
34 process. Additional observation wells may be installed as necessary to further monitor the
35 process.
36

37
38 **A.5.3.1.2 Produced Shale Oil and Gas.** Storage tanks and facilities will separate the
39 produced gases from the shale oil and water, and liquid streams would then be trucked off-site to
40 separate processing or disposal facilities. Preliminary estimates suggested production rates of
41 5 or more barrels per day after 1 year of initiating the heating process.
42

43
44 **A.5.3.1.3 Storage and Disposal of Materials and Waste.** The products used on-site
45 will be typical of the products used in the oil and gas industry (lubricants, diesel fuel, gasoline,
46 lubricating oils, solvents, and hydraulic fluid) and would be used, stored, and disposed of in

1 accordance with all industry standards and practices, as well as in compliance with all federal,
2 state, and local regulations. Smaller quantities of other materials, such as herbicides, paints, and
3 other chemicals, will be used during facility operation and maintenance. Any produced water
4 and/or flush water will be routed to 500-bbl storage tanks for transport off-site to an appropriate
5 disposal facility. Spent caustic will be stored in 50-bbl tanks and transported off-site for disposal.
6 No process wastewater is anticipated in the preliminary phases of the proposed project, but it is
7 expected in the later phases of the program. Drilling fluid returns will be processed by a
8 modularized solids control system to minimize spent drilling fluid generation. This system will
9 produce relatively dry cuttings with minimal associated drilling fluid. The drilled cuttings and
10 fluids will be collected in plastic-lined earthen pits approximately 100 ft by 100 ft with 6 ft of
11 usable depth (8 ft deep). One pit for each of the four proposed well patterns (each of which
12 would consist of 1 producer, 4 injectors, and 12 groundwater wells) would be anticipated. These
13 pits will be kept clean and free of oil and other harmful constituents, constructed in accordance
14 with industry regulations and BLM Gold Book standards and guidelines (DOI and USDA 2006),
15 and designed to meet BLM specifications to deter and/or prevent migratory birds and other
16 wildlife from accessing the contents. Used oil will be handled in accordance with Title 40,
17 Part 279 of the *Code of Federal Regulations* (40 CFR Part 279). A used oil recycler will be
18 contracted to handle all used oil. The proposed in-situ process will not include any aboveground
19 retort activities; therefore, no spent shale will be brought to the surface as a waste product.
20

21 The management, maintenance, and disposal of sanitary wastewaters will be contracted
22 through local providers. Solid waste products will be stored in closed, animal-proof containers so
23 as not to attract wildlife and to prevent trash from being blown off-site. All solid waste will be
24 managed, collected, and disposed of in accordance with existing laws and regulations by a local
25 contract provider. Other waste products will be collected and disposed of in accordance with
26 existing laws, stipulations, and regulations.
27

28 The proposed in-situ process will not include any aboveground retort activities; therefore,
29 no spent shale will be brought to the surface as a waste product.
30

31 Gas produced as a result of the proposed process will be burned as fuel or flared.
32 Produced shale oil would be stored in 100-bbl tanks and transported off-site for processing and
33 subsequent delivery to consumer markets.
34
35

36 **A.5.3.1.4 Water Requirements.** Table A-9 gives the amount of water consumed; water
37 use will be limited to mixing additives and drilling mud, suppressing dust, and various purposes
38 by personnel. The water required for construction and operation of the proposed process will be
39 purchased from local permitted sources and trucked to the site.
40

41
42 **A.5.3.1.5 Staffing.** The construction, drilling, and fracturing (Phases 1 through 4) of the
43 proposed process would require from 10 to 100 contractors and employees.
44
45

1 **A.5.3.1.6 Utilities.** Portable diesel generators will be used
 2 to provide the needed power during the preliminary phases of
 3 Chevron’s proposed RD&D project. Rights-of-way (ROWs) for
 4 power, communications, and natural gas will be constructed only if
 5 the fracturing phase was considered successful. The power line will
 6 be installed on elevated poles along with communication lines. The
 7 natural gas pipeline will be installed underground and will enter the
 8 proposed lease site by using the same 65-ft-wide combined ROW.
 9

**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

10 **A.5.3.1.7 Noise.** The noise generated by this technology
 11 will fluctuate with the alternate construction and operation phases
 12 of the project. The construction, well drilling, and fracturing phases
 13 would generate noise for 2 to 4 months or longer, depending on the
 14 success of initial operations. The active retorting phases of the
 15 proposed project will generate less noise, but that noise will occur
 16 24 hours a day over the life of the project. The noise-generating
 17 equipment for this process will be diesel and gas generators.
 18

Source: BLM (2006a).

19 Noise generated during the testing phase of the project will
 20 be from drill rigs installing monitoring wells and the heating/
 21 production wells. Equipment used will be designed to meet applicable Colorado Oil and Gas
 22 Conservation Commission allowable noise levels, which are expected to be 50 to 55 A-weighted
 23 decibels (dbA) for the tract in a rural/agricultural setting. Noise readings would be taken at the
 24 site during operations to verify noise levels.
 25

26
 27
 28 **A.5.3.1.8 Air Emissions.** Air pollutant emissions will occur during construction (due to
 29 surface disturbance by earthmoving equipment, vehicle traffic fugitive dust, drilling activities,
 30 facility construction, and vehicle engine exhaust) and during production (including power
 31 generation, product and CO₂ processing, and engine exhausts).
 32

33 The air pollution emission estimates were based on the best available engineering data
 34 assumptions and scientific judgment. However, where specific data or procedures were not
 35 available, reasonable but conservative assumptions were incorporated. For example, the air
 36 emission estimates assumed that project activities would operate at full production levels
 37 continuously (i.e., with no downtime).
 38

39
 40 **A.5.3.1.9 Transportation.** The proposed RD&D project will not create additional access
 41 onto BLM lands; it would, however, increase traffic on existing roadways and contribute to
 42 fugitive dust along the unpaved county roads necessary for access to the site.
 43
 44

1 **A.5.3.2 AMSO, LLC (formerly EGL)²⁹**

2
3 Information presented here regarding AMSO's RD&D project was taken from the EA of
4 the proposed activities (BLM 2006b). The AMSO project will use an in situ retorting technology
5 to test a 300-ft-thick section of the Mahogany Zone of the Green River Formation in the
6 Piceance Basin of Colorado. The AMSO tract is located approximately 27 mi west-northwest of
7 Rio Blanco, Colorado, on a ridge between Ryan Gulch and Black Sulphur Creek at elevations
8 ranging from 6,795 to 6,965 ft (Figure A-9). Both streams are tributaries of Piceance Creek.
9 Vegetation is 48% rolling loam sagebrush and 52% pinyon-juniper. Construction of the RD&D
10 facilities will be accompanied by clearance of 28 acres of rolling loam vegetation and 8 acres of
11 pinyon-juniper vegetation.

12
13 In the AMSO oil shale process, heat will be introduced by using heated fluids and/or
14 electric heaters near the bottom of the oil shale zones to be retorted. This will result in a gradual,
15 relatively uniform heating of the shale to 650 to 750°F to convert kerogen to oil and gas. It is
16 anticipated that once a sufficient amount of oil is released to surround the heating elements, a
17 broad horizontal layer of boiling oil will continuously release hot hydrocarbon vapors upward
18 and transfer heat to the oil shale above the heating elements.

19
20 The oil shale that will be tested at the EGL tract is a 300-ft-thick section composed of the
21 Mahogany Zone (R-7) and the R-6 Zone of the Green River Formation, the top of which is at a
22 depth of approximately 1,000 ft. The affected geologic unit will be approximately 1,000 ft long
23 and 100 ft wide. At an estimated richness of 26 gal of oil per ton of shale, the potential amount of
24 oil in the unit to be tested is more than 560,000 bbl per acre. For this test, however, the
25 Mahogany and R-6 Zones will be retorted; the oil shale below these zones, however, could still
26 be retorted at a later date on the 160-acre tract.

27
28 A number of heating fluids could be used. It is expected that steam will be used during
29 the initial heating phase of the development. During the later stages of processing, a high-
30 temperature, hot-oil heat-transfer medium, such as Dowtherm, Syltherm, and/or Paratherm,
31 might be used.

32
33 To introduce the heating fluids into the oil shale deposit, EGL's technology will involve
34 drilling five cased wells that would vertically penetrate nearly the full length of the oil shale
35 deposit to be tested. Once near the bottom of the oil shale zone, the wells will be drilled
36 horizontally for a distance of about 1,000 ft to the opposite side of the pattern. The wells will
37 then be directed/connected vertically upward through the oil shale and overburden to the surface.

38
39 To minimize lost circulation problems in the Uinta Formation and to avoid contaminating
40 any aquifers encountered, the wells will be drilled by using a flooded reverse-circulation method
41 that uses a combination of fresh water and air drilling. Bentonite and polymer will be used to
42 control viscosity and maintain the desired mud weight. Drilling will require about 80 bbl/day of
43 fresh water that would likely be purchased from local sources.

44

²⁹ American Oil Shale, LLC was formerly called EGL in the 2008 OSTs PEIS.

1 For the RD&D phase of the project, a 25-million-Btu/h trailer or a skid-mounted, direct-
2 fired, forced-circulation, steam-generation boiler will be used to heat the fluids. The boiler will
3 initially be fired by natural gas or propane, but after retorting of the oil shale had begun, the
4 boiler could be fired by gas and oil produced by the retorting process.
5
6

7 **A.5.3.2.1 Groundwater Management.** To reduce the amount of groundwater
8 infiltrating into the oil shale zone that would be heated, AMSO will establish a dewatered zone
9 in the retorting zone. This will be accomplished with four to eight pumping wells surrounding
10 the subsurface retort area. Extracted groundwater will be reinjected downgradient into the
11 equivalent aquifer intervals in order to maintain the regional water table and avoid disturbing
12 baseflow to nearby streams.
13

14 Upgradient and downgradient multilevel monitoring wells will be installed to
15 characterize the structure and properties of local aquifers, establish predevelopment baseline
16 groundwater conditions, better define the geology of the oil shale resource, and monitor water
17 quality.
18

19 After project completion, pumping and treating of contaminated groundwater will
20 continue until groundwater quality meets applicable regulatory standards.
21
22

23 **A.5.3.2.2 Produced Shale Oil and Gas.** During sustained operation, it is expected that
24 the product would be about 30% gas and 70% light oil, on the basis of heating value. Shale oil
25 produced during test operations will be separated from the gas and water produced with it and
26 stored in tanks at the test site. The shale oil will be trucked to markets in Colorado, Utah, and
27 Wyoming.
28
29

30 **A.5.3.2.3 Storage and Disposal of Materials and Waste.** Wastewater from the site,
31 including retort water (up to 50 bbl/day), boiler blowdown, and drilling waste, will be trucked to
32 a licensed disposal facility.
33

34 A variety of materials typical of the oil and gas drilling and production operations
35 prevalent in the Piceance Basin could be on-site during construction and operations, including
36 lubricants, diesel fuel, gasoline, lubricating oils, solvents, and hydraulic fluid. Smaller quantities
37 of other materials, such as herbicides, paints, and other chemicals, could be used during facility
38 operation and maintenance. These materials could be used to control noxious weeds, facilitate
39 revegetation on disturbed areas, and operate and maintain the facility during the life of the
40 project.
41

42 Solid waste (human waste, garbage, etc.) will be generated during construction activities
43 and during operation of the oil shale RD&D facility. Trash will be collected in animal-proof
44 containers and periodically hauled to a sanitary landfill in Rio Blanco County. All other wastes
45 will be collected and disposed of in a manner consistent with existing laws and regulations.
46

1 **A.5.3.2.4 Water Requirements.** Start-up, dust suppression, personnel requirements, and
2 drilling operations will require limited amounts of water (approximately 80 bbl/day for drilling)
3 that will be purchased and trucked to the site from local sources. Makeup water will be required
4 for the boiler to compensate for minor steam losses and to maintain dissolved solids in the boiler
5 at an appropriate level. Water needed for sustained operations will likewise be so acquired or
6 taken from wells on-site if possible. The total volume of water required from outside sources for
7 sustained operation will be approximately 27 bbl/day.
8
9

10 **A.5.3.2.5 Staffing.** It is estimated that a total of 10 to 40 employees will be required
11 during test operations; most employees will work during daylight hours. During construction of
12 the test facilities and drilling of the test wells, more workers will be needed, and their numbers
13 will vary from 10 to 100, depending on the phase of construction.
14
15

16 **A.5.3.2.6 Utilities.** A new power line will interconnect an existing power line southwest
17 of the tract and project facilities. The power line will extend approximately 1,760 ft from the
18 southwestern corner of the tract to the existing power line and have a 25-ft-wide ROW.
19 Construction of the power line could disturb as much as 1.0 acre outside the 160-acre tract
20 boundary.
21
22

23 **A.5.3.2.7 Noise.** Noise generated during the testing phase of the project will be from drill
24 rigs installing monitoring wells and the heating/production wells. Equipment used will be
25 designed to meet applicable Colorado Oil and Gas Conservation Commission allowable noise
26 levels, which are expected to be 50 to 55 dbA for the tract in a rural/agricultural setting. Noise
27 readings will be taken at the site during operations to verify noise levels.
28
29

30 **A.5.3.2.8 Air Emissions.** Air pollution emissions were estimated on the basis of the best
31 available engineering data assumptions and scientific judgment. However, where specific data or
32 procedures were not available, reasonable but conservative assumptions were incorporated. For
33 example, the air emission estimates assumed that project activities would operate at full
34 production levels continuously (i.e., with no downtime).
35

36 Table A-10 gives the estimated NO_x, carbon monoxide (CO), sulfur dioxide (SO₂),
37 PM₁₀, and PM_{2.5}³⁰ emissions associated with AMSO's project for both construction and RD&D
38 operation scenarios. The emission estimates include both an anticipated maximum daily basis
39 and an annual basis. The construction sources include fugitive dust from road traffic and surface
40 preparation and trenching construction activities and combustion emissions from drill rig
41 operations. Operation sources include combustion emissions from AMSO's boiler and fugitive
42 dust from road traffic. Construction and road traffic were modeled by assuming activities would
43

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.

TABLE A-10 AMSO 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).

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 will commute to the job site during the test phase. Most traffic will 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.

AMSO estimates that 10 light and 6 heavy vehicles will 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 will travel back and forth for a duration of 12 to 18 months. During the 3 to 4 years that the facility will be operating, approximately 15 light and 9 heavy vehicles per day would travel back and forth. During shale oil production, 3 tanker trucks will transload railcars at Lacy Siding west of Rifle each day. During reclamation, 2 light vehicles and 1 heavy

1 vehicle will travel to and from the site each day, for a duration of 3 to 4 years. Heavy vehicles
2 will include drill rigs, water trucks, and tanker trucks. Light vehicles will include passenger
3 vehicles, trucks, and vans. Equipment will be obtained locally, depending on equipment/drill rig
4 availability, and local services will be used whenever possible. Tankers will be of the standard
5 weight, size, and axle arrangements normally used in the State of Colorado without special
6 permits.
7
8

9 **A.5.3.3 Shell Frontier Oil and Gas**

10
11 Shell is conducting RD&D projects on three separate 160-acre sites in the northern part
12 of the Piceance Basin in Rio Blanco County, Colorado (Figure A-9); information presented here
13 regarding these projects is taken from the EA of the proposed activities (BLM 2006c). The
14 elevation of the sites ranges between 6,580 and 7,060 ft. The sites will be used to test different
15 methods of shale oil extraction, all of which are based on Shell's proprietary ICP that converts
16 kerogen contained in oil shale into ultraclean petroleum liquids and gas that require less
17 processing to become finished transportation fuels (e.g., gasoline and jet and diesel fuels). The
18 majority of the 160 acres for each of the sites will be affected through ground disturbance and
19 the construction of buildings and associated infrastructure.
20

21 The three sites have the following variations:

- 22
- 23 • Site 1: ICP—implemented by recovering hydrocarbons from kerogen using
24 self-contained heaters that heat the shale rock.
25
- 26 • Site 2: Two-Step ICP—implemented by initially extracting nahcolite by
27 injecting hot water into the shale and then recovering hydrocarbons through
28 ICP once the nahcolite is removed.
29
- 30 • Site 3: Electric-ICP (E-ICP)—implemented by recovering hydrocarbons from
31 kerogen using bare-wire heaters to heat the rock; some of the heating is
32 created by the flow of electricity through the shale formation.
33
34

35 **Site 1 Technology: ICP.** For Shell Oil Shale Test Site 1, a freeze wall will be installed to
36 prevent groundwater from flowing into areas where ICP is being used. A series of 150 holes
37 approximately 8 ft apart will be drilled where the freeze wall would be created. The freeze holes
38 will be drilled to a depth of approximately 1,850 ft. A chilled fluid (−45°F) will be circulated
39 inside a closed-loop piping system and into the holes. The cold fluid will freeze the nearby rock
40 and groundwater, and in 6 to 12 months, it will create a wall of frozen ground. The freeze wall
41 will be maintained during both the production and reclamation phases of the ICP project.
42

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

1 Approximately 30 heater holes will be drilled in the interior of the containment zones,
2 spaced 25 ft apart, and electric heaters will be installed to uniformly heat the otherwise
3 undisturbed hydrocarbon-bearing shale to between 550° and 750°F for a period of several years.
4

5 Additional holes will be used to monitor subsurface conditions (e.g., temperatures,
6 pressures, and water levels). The monitoring holes will be placed inside and outside the freeze
7 wall.
8

9 After ICP treatment, pumping water into the heated zone will allow recovery of the
10 remaining hydrocarbons. This process, followed by a pump-and-treat process with water and
11 possibly bioremediation, will reduce the amount of hydrocarbons in the heated shale to
12 acceptable levels. Then the freeze wall will be allowed to thaw.
13
14

15 **Site 2 Technology: Two-Step ICP.** Although significant areas of the Piceance Basin are
16 amenable to ICP technology, the presence of excessive amounts of nahcolite limits the
17 applicability of ICP in portions of the Piceance Basin. Nahcolite, also known as baking soda or
18 sodium bicarbonate, occurs naturally within shale. The process to be used at this test site will be
19 nearly the same as the process to be used in Site 1, with the exception of the extraction of
20 nahcolite prior to removal of hydrocarbon material. The drilling for the freeze walls, heater
21 holes, and extraction will be the same. Removal of the nahcolite prior to implementation of ICP
22 will be required for efficient recovery of both the nahcolite and the petroleum products in the
23 kerogen. Shell has demonstrated that nahcolite can be solution-mined by circulating hot water
24 through the shale. The nahcolite, which is dissolved into the hot water and recovered from the
25 hot water after it is pumped back to the surface, is a product of this process. Removal of the
26 nahcolite increases the permeability and porosity of the remaining rock matrix and significantly
27 improves the thermal efficiency in recovering petroleum from the oil shale when the ICP process
28 is used.
29

30 This two-step ICP technology will have a number of energy-saving benefits. The hot
31 water used for nahcolite decomposition could be heated by using waste heat from previous areas
32 where ICP had been implemented. Solution mining will preheat the oil shale in the mined zone
33 to at least 250°F using otherwise wasted heat. The water used for cooling the ICP-treated oil
34 shale will pass through a surface heat exchanger to heat the water used for nahcolite solution
35 mining, providing additional energy savings.
36

37 Removing the nahcolite and then dewatering will reduce the mass within the formation
38 that must be heated to ICP temperatures, ultimately reducing the ICP energy requirements.
39 Solution mining the nahcolite will increase the speed at which a heat front would move within
40 the formation, thus reducing the time and energy requirements to produce oil and complete the
41 project.
42

43 A freeze wall will be created before initiating nahcolite solution mining and will be
44 maintained through implementation of ICP to contain groundwater. Following the solution
45 mining of the nahcolite, electric heaters will be installed to heat the shale to ICP temperatures,
46 and the solution mining holes will be converted to hydrocarbon production wells. The boundary

1 between the solution-mined nahcolite-ICP region and the remaining nahcolite-bearing strata will
2 provide an impermeable wall, in addition to the freeze wall, to prevent hydrocarbons from
3 migrating out of and water coming into the heated area.

4
5 After ICP treatment occurred, the pumping of water into the heated zone will allow
6 recovery of the remaining hydrocarbons. This process, followed by a pump-and-treat process
7 with water and possibly bioremediation, will reduce the amount of hydrocarbons in the heated
8 shale to acceptable levels. Then the freeze wall will be allowed to thaw.

9
10
11 **Site 3 Technology: Advanced Heater Test Site (E-ICP).** The process used at Site 3 will
12 be nearly the same as that used for Site 1 in terms of the amount and type of drilling and the
13 extraction process. However, the technology for heating will be different. The economics of the
14 ICP process could be improved dramatically if bare electrode heaters were installed that
15 combined both thermal conduction and some heating generated by electricity flow through the
16 shale formation. The bare electrode process is called E-ICP and is a patented in situ heating
17 technology. The project will include about 70 to 100 vertical heaters spaced 20 to 40 ft apart.
18 The bare electrode heaters are about 1,950 ft long and are designed to concentrate most of their
19 heat output in the bottom 1,000 ft. With lower heater well capital costs and greater energy
20 efficiency, E-ICP might increase the oil shale target resource by making much more of the
21 Piceance Basin commercially attractive. Other than the difference in heater technology, the
22 remainder of this process is comparable to the Oil Shale Test (Site 1).

23
24
25 **A.5.3.3.1 Groundwater and Surface Water Management.** Groundwater monitoring
26 will be conducted at each site to assure compliance with groundwater regulations during and
27 after the project.

28
29 Water requirements will vary throughout the life of each project. Water will be trucked to
30 the sites for initial construction and drilling activities. Potable water will be trucked to the sites
31 throughout the life of the facilities.

32
33 Once a freeze wall is formed, the water inside the wall will be removed by pumping prior
34 to heating. The groundwater pumped from inside the freeze wall will be injected into wells
35 located outside the freeze wall. The injection wells will be permitted per the requirements of the
36 EPA Underground Injection Control Program.

37
38 During heating, water removed from within the freeze wall, along with the hydrocarbon
39 products, will be treated in the processing facilities and recycled or discharged. Water used to
40 recover nahcolite will be recycled into the process. Water that cannot be recycled or otherwise
41 used will be treated to appropriate discharge standards in a process water treatment plant and
42 released to surface drainage in a manner consistent with the requirements of a Colorado
43 Department of Public Health and Environment discharge permit.

44
45 Groundwater will be used only after state approvals are received. Water wells will be
46 drilled to provide additional water required by the operations, especially during reclamation

1 following completion of hydrocarbon recovery. Reclamation will include flushing and cooling of
2 the shale inside the freeze wall.

3
4 During dewatering operations, water from the dewatered zone will be reinjected into the
5 same zone or potentially a different zone at another location on the property.

6
7 The pyrolysis process occurring within the approximately 130-ft by 100-ft test area will
8 likely increase the porosity of the oil shale intervals because of the removal of kerogen, resulting
9 in an increase in horizontal hydraulic conductivity. Shell's testing to date, using its heating
10 process on oil shale materials, suggests that the porosity of the rock will increase by about 30%
11 as a result of the pyrolysis of kerogen and removal of oil. There will likely be a minimal increase
12 in the vertical hydraulic conductivity associated with the heating effect on the rock mass. The
13 removal of kerogen is not anticipated to affect the aperture widths of preexisting joints or
14 fractures.

15
16 Heating of the oil shale during the pyrolysis phase could increase the vertical
17 permeability of the confining units by enlarging preexisting joints or fractures. The potential
18 consequence of the increased fracture apertures is that groundwater could flow more easily
19 between the Upper and Lower Parachute Creek Units.

20
21
22 ***Produced Shale Oil and Gas.*** For Sites 1 and 3, oil and gas production is expected to be
23 approximately 600 bbl/day of oil or 1,000 bbl/day of oil equivalent (oil and gas) at full
24 production. Oil and gas coming to the surface via the previously installed producer holes will be
25 collected for further processing by traditional processing techniques. Full oil and gas production
26 for the Nahcolite Test Site 2 will be approximately 1,500 bbl/day of oil in the form of untreated
27 synthetic condensate.

28
29 The recovered product will include a mixture of liquid hydrocarbons, gas, and water that
30 will be processed further to remove impurities and ready the products for transport off-site or
31 reuse in the recovery process. This recovery process is a typical process used in the oil and gas
32 industry.

33
34 The initial processing will separate the recovered product into three streams: liquid
35 hydrocarbons, sour gas, and sour water. The term "sour" refers to the presence of sulfur
36 compounds and CO₂. Once the three streams are separated, each stream will be further processed
37 to remove impurities. The waste streams generated during much of the processing will be
38 recycled for further treatment.

39
40
41 ***Nahcolite Recovery (Site 2).*** The nahcolite mining solution will be pumped to a
42 processing building where the mineral will be removed. The process will remove the mineral
43 from the water in a series of steps; the product will then be dried, stored, and loaded for market.
44 Hot solution will be cooled; because the mineral is less soluble, it would crystallize. Centrifuges
45 will drive off water to concentrate the crystallized material. The water will be reheated and
46 recycled as barren solution. CO₂ will be used to make a final product (sodium bicarbonate).

1 To minimize disturbance, the groundwater reclamation facilities will be built at the same
2 location as the nahcolite processing facility. Additional engineering evaluations will optimize the
3 site arrangements for these facilities.
4

5
6 **Refrigeration System.** Appropriate procedures for storage, handling, and emergency
7 response for ammonia chemicals used in the refrigeration system will be included in the Process
8 Safety Management Manual to be developed in accordance with Occupational Safety and Health
9 Administration regulations prior to operation. Emergency response procedures, including
10 procedures for cleanup of spills and notification requirements, will be included in the Emergency
11 Response Plan developed prior to operation.
12

13
14 **A.5.3.3.2 Storage and Disposal of Materials and Waste.** During the course of
15 construction and operation, a variety of by-products and waste materials will be generated at
16 each of the three sites. They will include construction waste, drill hole cuttings, garbage, and
17 miscellaneous solid and sanitary wastes.
18

19 Surface construction operations will result in a variety of small waste products that might
20 include paper, wood, scrap metal, refuse, or garbage. These materials will be collected in
21 appropriate containers and recycled or disposed of off-site in accordance with applicable
22 regulations.
23

24 Approximately 200,000 ft³ of earth and rock materials will be generated at each test site
25 during drilling operations for the project. Drill cuttings removed from the drilled holes will be
26 dewatered so that the water can be recycled back to the drill rigs. The dewatered cuttings will be
27 placed into a cutting pit. These nontoxic, non-acid-forming drill cuttings will be separated from
28 free water and buried below grade. Burial depth and soil coverage will be sufficient such that the
29 materials will not impede revegetation.
30

31 During operation, garbage from the site will be collected in appropriate containers and
32 disposed of off-site. Waste oils, reagents, and laboratory chemicals that are not collected in
33 sumps and treated at the water treatment plants will be recycled or disposed of off-site in
34 accordance with applicable regulations.
35

36 The process of producing hydrocarbons from the oil shale will require processing and
37 treating multiple materials. The production complex will include a refrigeration facility,
38 nahcolite recovery process (at Site 2), groundwater reclamation facility, and hydrocarbon
39 processing facility. Spill prevention, control, and countermeasure plans and best management
40 practices will need to be implemented for each stage of production and for all processing
41 facilities. In addition, all waste by-products from the site will need to be properly transported and
42 disposed of according to all rules and regulations regarding the specific waste by-product. These
43 waste by-products will include but not be limited to biosolids effluent and reverse-osmosis reject
44 effluent.
45

1 A combination of sanitary waste handling methods will be employed. Some sanitary
2 waste, such as that collected in temporary toilet facilities, may be shipped to an approved facility
3 for off-site treatment and disposal. Any gray water or black water disposed of on-site will be
4 treated in an appropriate sewage processing unit or disposed of according to standards via an
5 approved septic system with a clarifier and drain field.
6
7

8 **A.5.3.3.3 Water Requirements.** Water requirements will vary throughout the project
9 life. Water uses will include construction, potable water, dust control, drilling, processing,
10 filling, and cooling of the heated interval for reclamation, and rinsing of the zone inside the
11 freeze wall.
12

13 Water will be trucked to the site for initial construction and drilling activities. Potable
14 water for personnel consumption will be trucked to the site throughout the life of the facilities.
15

16 On-site water will be used for most operational uses and will be supplied from water
17 wells drilled for that purpose. The well will supply water needed for processing and reclamation.
18 Peak pumping demand (250 to 300 gpm, approximately 400 to 480 ac-ft/yr) will occur during the
19 cooling and resaturation phase of the reclamation cycle. If the water well is available during
20 construction and drilling, this water will supplement or replace construction and drilling water
21 trucked to the site.
22

23 Water needs for each phase of the operation are outlined below and summarized in
24 Table A-11. The projected water needs are estimates and are subject to change as additional
25 information becomes available and facility designs are finalized. The estimate of the amount of
26 water needed for process water in the 2006 EA was 10 gpm. This water will be supplied from
27 groundwater extracted from either the Uinta or Upper Parachute Creek Units. Water rights
28 required for the project will be acquired prior to start-up of the operation. The combined annual
29 volume of water required for all three sites was unknown at the time the 2006 EA was prepared
30 and would vary on the basis of when each project started and how each project progressed. On
31 the basis of the assumption that all three sites would operate at the same time for at least 1 year,
32 the combined process water needs will be a minimum of 30 gpm. This flow rate equates to an
33 annual volume of almost 48 ac-ft/yr.
34

35 Construction water will be trucked to the sites as necessary to meet needs for compaction,
36 dust control, and miscellaneous uses. Potable water needed during construction would be brought
37 to the sites. Water required for drilling will be trucked to the sites until water from the on-site
38 water supply well is available to supplement or replace trucked water.
39

40 Water will be needed for various processing and operating needs. Water removed with
41 the hydrocarbon products will be treated in the processing facilities and recycled or discharged at
42 a permitted discharge point. The locations of discharge points had not been determined in the
43 2006 EA. It is anticipated that excess water will be available during the initial processing period
44 as a result of dewatering operations from within the freeze wall containment area and that there
45 will be no need for the water supply well to provide water for processing during this initial
46 period. As processing progresses, there will be a need for additional water.

1 **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)

^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.

Source: BLM (2006c).

2
3
4

1 Water will also be needed to conduct reclamation filling and cooling of the heated
2 interval within the freeze wall containment barrier as well as for rinsing the heated interval. This
3 water will be a combination of recycle water and makeup water from the water supply well, as
4 needed. During reclamation, a water supply will be needed for initial stages of flushing and
5 cooling. Two wells would be completed in the upper Parachute Creek Unit to serve as
6 reclamation water supply wells. However, only one well would be used at a time.
7
8

9 **A.5.3.3.4 Staffing.** Employment of the maximum number of people at the sites will
10 occur during construction and drilling. An estimated maximum of approximately 720 individuals
11 would be employed at Sites 1 and 3 during the construction and drilling period. At Site 2, an
12 estimated maximum of approximately 700 individuals would be employed during the
13 construction and drilling period. However, because the three test sites will not be developed at
14 the same time, the number of workers employed during construction and drilling would not be
15 cumulative. Once construction is completed, the maximum expected employment will be
16 approximately 155 individuals at Sites 1 and 3, and 150 individuals at Site 2.
17
18

19 **A.5.3.3.5 Utilities.** Estimates of electricity and gas requirements were not provided in
20 the EA.
21
22

23 **A.5.3.3.6 Noise.** Noise generated during the testing phase of the project will be from drill
24 rigs installing monitoring wells and from the heating/production wells. Equipment used will be
25 designed to meet applicable Colorado Oil and Gas Conservation Commission allowable noise
26 levels, which are expected to be 50 to 55 dbA for the tract in a rural/agricultural setting. Noise
27 readings will be taken at the site during operations to verify noise levels.
28
29

30 **A.5.3.3.7 Air Emissions.** The air pollution emission estimates for each of the three Shell
31 sites were based on the best available engineering data assumptions and scientific judgment.
32 However, when specific data or procedures were not available, reasonable but conservative
33 assumptions were incorporated. For example, the air emission estimates assumed that project
34 activities would operate at full production levels continuously (i.e., with no downtime).
35
36

37 **A.5.3.3.8 Transportation.** Access to each of the three sites will be provided by
38 constructing an access road to connect the site to existing county roads. Initial construction
39 activities will include development of the site access road to a running width of approximately
40 24 ft to allow heavy equipment to travel in two directions. The access road will be paved with
41 asphalt for the 24-ft width and include appropriate ditches and culverts to maintain drainage
42 control. Access to the sites from public roads will be restricted by an entry gate. An estimated
43 300 to 650 vehicles per day will access the sites during construction.
44
45

1 **A.5.3.4 Enefit American Oil (Formerly OSEC)³¹**

2
3 In 2011, Enefit acquired the former OSEC RDD lease at the White River Mine site
4 (160 acres) in Uintah County, Utah (Figure A-9). OSEC had proposed a three-phase RD&D
5 project to test shale oil recovery by using the ATP retort technology and by providing incoming
6 natural gas via a pipeline through the “western” ROW alignment. Information presented here
7 regarding this project is taken from the EA of OSEC’s proposed activities (BLM 2007). As
8 OSEC originally proposed, Enefit will employ underground mining and aboveground retorting.
9 However, the company will employ its own version of the proposed technologies reviewed here
10 based on its Enefit280 plant under construction in Estonia (Enefit 2011). The ATP system
11 proposed by OSEC is a thermal process for pyrolyzing oil shale. The primary unit is the ATP
12 Processor, which is a modified horizontal rotary kiln. The ATP Processor has four internal zones
13 in which the four stages of ore processing occur: (1) preheating of the feedstock, (2) pyrolysis of
14 the oil shale under anaerobic conditions, (3) combustion of coked solids to provide the process
15 heat requirements, and (4) cooling of the combustion products by heat transfer to the incoming
16 feed.

17
18 *Phase 1* of the project is expected to last approximately 11 months according to the
19 2007 EA. During this time, OSEC, now Enefit, will remove approximately 1,000 tons of oil
20 shale from the White River Mine’s on-site surface stockpile for processing at the existing ATP
21 pilot plant unit in Calgary, Alberta, Canada.

22
23 According to the EA, the 1,000 tons of shale will be transported by truck from the
24 160-acre lease out of the project area to a gravel pit in Uintah County, where the material will be
25 crushed to design specifications (–3/8 in.). The crushed shale (total 1,000 tons) will be trucked to
26 Calgary for testing by UMATAC in its 4-ton/h ATP Processor pilot plant. During Phase 1, no
27 crushing of oil shale will be performed within the White River Mine lease area.

28
29 According to the EA, about 650 bbl of raw shale oil will be produced from the 1,000 tons
30 of oil shale processed. Approximately 800 tons of non-Resource Conservation and Recovery Act
31 (RCRA) hazardous spent shale will be produced from the processing of the 1,000 tons of feed
32 shale. Samples of this material will be retained for testing and analysis in Canada and the United
33 States. The remaining spent shale will be disposed of in a licensed landfill in Alberta, or it would
34 be stored on-site in Alberta pending identification of a beneficial reuse.

35
36 No fuel storage, office facilities, overnight accommodations, toilets, or drinking water
37 supply will be established at the White River Mine lease area during Phase 1. Although the
38 loading and trucking operation is not expected to be dusty, some minor amounts of water may be
39 required to control dust during the loading of the shale feed into the trucks at the White River
40 Mine. All water required for this phase will be trucked in by a local supplier and dispensed from
41 a water truck. No water rights will be needed for this phase of work. The fugitive dust emissions
42 associated with loading the oil shale from the existing surface stockpile, road dust, and exhaust
43 emissions from the front-end loader and trucks (short-term activities) will be the only air
44 emissions associated with the Phase 1 operations within the 160-acre leasehold.

³¹ Enefit American Oil was formerly called OSEC in the 2008 PEIS.

1 *Phase 2* of the RD&D project will last about 14 months and involve the mobilization of
2 the UMATAC 4-ton/h ATP Processor pilot plant and associated equipment from Calgary to the
3 White River Mine lease area. Shale for processing will initially come from the existing surface
4 stockpiles. Enefit will reopen the White River Mine and begin mining fresh oil shale for use as
5 feed to the plant during the latter stage of Phase 2.
6

7 Phase 2 construction will involve a relatively small amount of new construction work on-
8 site. The trailer-mounted ATP pilot plant will be mobilized from Calgary and set up on-site on an
9 impervious base pad. A fuel tank area will be constructed with a liner and an embankment
10 surrounding it. An additional aboveground storage tank area will be established for shale oil
11 product storage and load out; these tanks will sit on a liner within an embankment. There will
12 also be a facility for on-site crushing, stockpiling, and ore handling.
13

14 The major Phase 2 construction activity will involve reopening the mine and constructing
15 a spent-shale disposal area. Approximately 10,000 tons of oil shale will be processed through the
16 ATP Processor pilot plant during Phase 2.
17

18 *Phase 3* of the RD&D project will involve the design, permitting, and fabrication of a
19 250-ton/h ATP Processor demonstration plant and construction of that plant within the 160-acre
20 lease area. It will require 2 years to permit, engineer, and construct the plant. Also, the mine will
21 be developed sufficiently to support the mining of 1.5 million tons/yr of oil shale, which will be
22 used as feed for the operation of the demonstration plant. Following commissioning, the plant
23 will operate for 2 years so enough operational, technical, environmental, and financial
24 information can be compiled to make an informed decision on whether to proceed to a
25 commercial project.
26

27 Preparation for Phase 3 operations will involve significant on-site construction activity,
28 particularly related to the new 250-ton/h ATP demonstration plant and all the ancillary
29 equipment. Many of the demonstration plant components will be fabricated elsewhere and
30 transported to the site for final assembly and erection. This will lessen the amount of laydown
31 space required during construction and the number of construction workers needed at the site.
32 The most significant permanent surface feature constructed during Phase 3 will be the 38-acre
33 storage area for containing the 2.2 million tons of spent shale that may be generated during this
34 phase of work.
35

36 Approximately 2.7 million tons of oil shale will be processed through the ATP Processor
37 demonstration plant during Phase 3. The source of the shale feed will be the reopened mine. All
38 mined shale will be stockpiled and crushed/blended at the surface within the 160-acre lease area.
39 It is expected that all shale mined will be processed (i.e., there will be no fines rejects produced
40 during the shale crushing activities).
41

42 In addition to the construction of the ATP Processor plant and ancillary equipment on the
43 160-acre lease, it will be necessary to construct/install natural gas, electric power, and water lines
44 along the proposed ROWs.
45
46

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

7
8 During Phase 3, 2.2 million tons of spent shale will be produced and disposed of at a
9 38-acre storage area. Minor amounts of construction-related wastes will also be generated during
10 the rehabilitation of existing structures and the construction of new facilities and structures
11 associated with the Phase 3 250-ton/h demonstration work. Such wastes could include scrap
12 metal or wood, concrete, and miscellaneous trash from the packaging of the construction
13 materials. These materials will be temporarily staged in roll-offs and trucked to an off-site solid
14 waste facility.

15
16 Shale oil typically contains 0.5 to 0.75% sulfur (OTA 1980b). Sulfur compounds
17 generated during retorting and secondary processing (hydrotreating) are primarily in the form of
18 H₂S, with lesser amounts of mercaptans. Through the treatment train process (i.e., air emission
19 control devices and/or wastewater treatment), sulfur-bearing solid wastes will be generated.

20
21 The hydrotreatment process will generate a variety of waste products, including sulfur-
22 containing residuum and spent catalysts. Spent catalyst, which is considered a listed RCRA
23 hazardous waste (K071), will consist of aluminum silicate and various metals (typically cobalt,
24 molybdenum, nickel, and/or tungsten). These waste materials will be disposed of at an
25 appropriate off-site disposal facility. Prior to disposal, the wastes will be contained in waste
26 storage areas built with appropriate spill containment features.

27
28 Occasionally, waste oils will be generated from equipment maintenance activities during
29 Phases 2 and 3. In addition, the hydrotreatment process and wastewater treatment of the process
30 waters will produce large volumes of oily sludges. All such materials will be temporarily stored
31 on the 160-acre lease site and trucked off-site to a licensed facility for treatment and disposal.

32
33
34 **Mine Water.** During Phase 2, the mine will be dewatered as part of the reopening
35 process. Mine water of good quality will be discharged to the existing retention dam area. The
36 exact volume of such water is not known, but it would amount to more than 2 million gal if the
37 water was pooled to the top of the Birds Nest Aquifer. Mine water below the bulkhead may
38 contain levels of petroleum-based compounds resulting from contact with the oil shale and the
39 bitumen seep in the lower portion of the mine. This water will likely be trucked off-site for
40 treatment and disposal at an approved facility.

41
42 During mining operations, water from dewatering of the mine may contain petroleum-
43 based compounds. During Phase 2 operations, this water will be temporarily stored in tanks.
44 Depending on test results, it will then either be discharged to an on-lease drainage channel to
45 flow toward the retention dam area (if the test showed that it met agreed-upon discharge criteria)

1 or trucked off-site. The appropriate frequency of testing the water will be stipulated on the basis
2 of the results from the initial test of mine water conducted prior to the reopening of the mine.
3

4 During Phase 3, mine water that did not meet water quality standards will be treated
5 through the process wastewater treatment system, along with wastewater from the air treatment
6 and hydrotreatment processes.
7

8
9 **Connate and Retort Water.** Approximately 150 tons (35,700 gal) of connate water
10 (water trapped in shale pore spaces) will be generated during Phase 2, and 40,000 tons
11 (9.5 million gal) will be generated during Phase 3. The connate water may be suitable for use in
12 remoistening and cooling the spent shale without treatment. If the connate water does not meet
13 appropriate criteria, it will be trucked off-site for treatment and disposal during Phase 2 RD&D
14 activities and will be treated in a wastewater treatment system on the 160-acre lease site during
15 Phase 3.
16

17 Approximately 200 tons (48,000 gal) of retort water (chemically bound moisture in the
18 shale) will be generated during Phase 2, and approximately 55,000 tons (13.2 million gal) will be
19 generated during Phase 3. Retort water often contains phenols, H₂S, or trace levels of petroleum
20 constituents that may require treatment before the water can be used for cooling and moistening
21 spent shale or discharged to an existing retention dam. During Phase 2, all retort water will be
22 temporarily stored on the lease site, tested, and, if it meets appropriate water quality criteria, used
23 to cool the spent shale or trucked off-site for treatment and disposal. During Phase 3, a
24 wastewater treatment facility on the 160-acre lease site will be used to treat the retort water to
25 remove H₂S, NH₃, phenols, and other constituents of concern. It is anticipated that following
26 treatment, nearly all of the water will be used to cool and moisten the spent shale or otherwise
27 reused in the process. Small amounts of water not needed for cooling and moistening the spent
28 shale may be discharged to a drainage feature leading to the retention dam area.
29

30 Process washdown is water that is regularly used to clean the retort and other equipment
31 during the on-site operations. Such water may contain high levels of sediment, and it may also
32 contain oily residues from the equipment.
33

34 All the sour water generated during Phase 3 will be stored and treated on-site prior to
35 being used for controlling dust or moistening the spent shale. Depending on chemical analysis
36 results, the sour water treatment may include stripping of NH₃ and H₂S, followed by biological
37 aeration.
38

39
40 **Sanitary Sewage Effluent.** During routine daily operations in Phase 2 and Phase 3,
41 workers will generate sanitary wastes. These, along with other wash water, will be processed in
42 an existing closed sanitary wastewater treatment system on the 160-acre lease site. Any sanitary
43 sewage generated before the repair and testing of the on-site system will be collected and trucked
44 to an off-site wastewater treatment plant.
45
46

1 **A.5.3.4.2 Produced Shale Oil and Gas.** Approximately 6,000 bbl of raw shale oil will
2 be produced during Phase 2. All oil produced will be temporarily stored in aboveground tanks
3 located within the 160-acre lease area before being trucked to an off-site facility for sale.
4

5 Approximately 1.8 million bbl of raw shale oil is expected to be produced during
6 Phase 3. It is anticipated that this oil will be hydrotreated on-site to produce a synthetic crude oil
7 product. The synthetic crude oil will be temporarily stored in aboveground tanks on-site. The
8 product will be trucked off-site to a refinery or delivered to a nearby pipeline that will have the
9 capacity and specifications to accept this upgraded shale oil.
10

11
12 **A.5.3.4.3 Water Requirements.** The amount of makeup water required in Phase 2 for
13 processing the oil shale is estimated to be approximately 2 bbl (84 gal) per ton of shale feed, half
14 of which will be needed to cool and moisten the spent shale. This means that the total makeup
15 water requirement for Phase 2 will be 20,000 bbl of water. Small amounts of additional water
16 may be required on-site for drinking, cooking, laundry, and toilet facilities for the Phase 2
17 workforce. All Phase 2 water needs (potable and process) will be trucked to the site by a local
18 supplier that has the appropriate water rights. The water will be stored in aboveground tanks
19 within the 160-acre lease area. No water rights will be needed by Enefit for this phase of work.
20

21 The total amount of Phase 3 water needed to process the oil shale (i.e., makeup water) is
22 estimated to be on the order of 4.1 million bbl. This is equivalent to a peak water demand of
23 380,000 gal/day while the processing plant is operating. The makeup water will be supplied from
24 water wells established in the Birds Nest Aquifer (two to three wells located in the northwestern
25 portion of the 160-acre lease site), from wells in the White River alluvial deposits (wells installed
26 as part of the earlier mine development activities that are north of the 160-acre lease), or from a
27 direct intake in the White River. Water pumped from these sources will be stored in aboveground
28 tanks on-site.
29

30 A potable water tank will be placed near the trailers to supply domestic needs; the potable
31 water will be trucked to the site. A process water tank with a capacity of about 750 bbl will be
32 installed next to the plant.
33

34
35 **A.5.3.4.4 Staffing.** It is estimated that the operational workforce at the site during
36 Phase 3 operations will be composed of approximately 120 individuals. Offices and shower and
37 toilet blocks will be provided on-site.
38

39
40 **A.5.3.4.5 Utilities.** Electricity required for the mine, pilot plant, and on-site
41 accommodations will be provided by diesel generators established within the 160-acre lease area
42 (1-MW total capacity). Propane will be used to provide heat to the process during start-up
43 periods as well as heat for office and field trailers. Also, diesel fuel will be used to run surface
44 and underground mine vehicles and equipment on-site. All diesel and propane fuel will be
45 trucked in and stored on-site in aboveground tanks. The diesel tanks will be placed in lined and
46 bermed containment areas.

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

5
 6 Natural gas or propane will be required for the operation of the ATP Processor
 7 demonstration plant. Further studies are required to assess whether it will be feasible to truck in
 8 propane gas or whether a pipeline connection to a natural gas supply will be required.

9
 10
 11 **A.5.3.4.6 Air Emissions.** The sources of air emissions will vary during the three phases
 12 of RD&D activities on the site. These sources are listed by phase in Tables A-12 through A-16.
 13 The ATP unit and the hydrotreatment unit will be fully permitted under the Clean Air Act and
 14 have all the emission control equipment required by the Act.

15
 16 Greenhouse gas emissions will be generated on-site during both Phase 2 and Phase 3
 17 operations. They will originate mostly from the retorting of the shale feed (see Tables A-12 and
 18 A-13, respectively). Additional greenhouse gas emissions will be produced from the burning of
 19 coal at the Bonanza Power Plant to generate electric power.

20
 21 Enefit's current projected timeline is to complete construction of a 25,000-bbl/day
 22 production facility in 2017, begin production at 25,000 bbl/day in 2020, complete construction of
 23 a second stage 25,000-bbl/day facility in 2021, and begin production at a rate of 50,000 bbl/day
 24 in 2024. These projections assume that Enefit's current 160-acre lease will be expanded to
 25 include its 4,960-acre BLM preferential lease area to a total of 5,120 acres, once Enefit
 26 demonstrates the commercial viability of shale oil production.

27
 28
 29 **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 ³	--	--	--	--	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

30
 31 Source: This table is reproduced as contained in Table A-12 of BLM (2007).
 32
 33

1 **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>						

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3 Source: This table is reproduced as contained in Table A-13 of BLM (2007).
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1 **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.A, <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.A, <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>						

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Source: This table is reproduced as contained in Table A-14 of BLM (2007).

1 **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.			

2
3 Source: This table is reproduced as contained in Table A-15 of BLM (2007).
4
5

6 **A.5.3.5 ExxonMobil**

7
8 Exxon Mobil submitted a proposal for an RD&D project in 2010 in response to BLM's
9 second-round solicitation. The project would employ in situ technologies to extract kerogen and
10 possibly, sodium mineral resources from below ground and would be located on 160 acres just
11 east of several current RD&D projects in the Piceance Basin in Colorado, as shown in
12 Figure A-9. The following discussion is based on information in the Plan of Operation for the
13 proposed project (ExxonMobil 2011).
14

15 ExxonMobil proposes to use its Electrofrac™ process, which is designed to heat oil shale
16 in situ by building a hydraulic fracture in the oil shale and filling the fracture with an electrically
17 conductive material. As electricity is conducted through the material, it serves as a resistive
18 heating element. Heat flows from the fracture into the oil shale formation, gradually converting
19 the solid organic matter of the oil shale into oil and gas. The oil and gas are produced by
20 conventional methods. No circulating fluid is expected to be required to recover hydrocarbons.
21 Upon conclusion of hydrocarbon production, ExxonMobil proposes to test a second patented
22 technology to recover sodium-bearing minerals. As the formation cools, some production wells

1 **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.			

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Source: This table is reproduced as contained in Table A-16 of BLM (2007).

would be converted to water injection wells for this purpose. Water would be injected into the fracture network and, heated upon entry into the hot oil shale, would dissolve sodium-bearing minerals, which would be recovered in the produced water. Recovered natrite could then be converted to sodium bicarbonate, as needed, with the addition of carbon dioxide.

Design and Permitting (Years 1–2) will involve road construction, site preparation and installation of facilities. An estimated maximum of 1 to 4 miles of existing road upgrades and new roads will be needed within the proposed lease area and to connect with nearby County Road 83. Total surface disturbance will not exceed 50 acres at any given time, exclusive of roads, utilities, and produced water and gas pipeline right of ways. Site buildings will include a temporary building or trailer for office space, and a warehouse or storage shed for equipment. A

1 fence surrounding areas of activity will protect livestock and wild game. Electricity will either be
2 provided through a tie-in with the local electrical grid, or will be supplied from portable
3 generators equipped with appropriate noise and emission controls. Water for all needs will be
4 trucked to the site.

5
6 *Phase I (Year 3)* will focus on drilling and subsurface work to construct two successful
7 Electrofrac™ fractures at depth. Successfully building an electrically conductive fracture in the
8 zone of interest is critical to further research phases.

9
10 *Phase II (Year 4)* will focus on installation of production and monitoring wells; installing
11 a utility tie-in and production headers and piping; and erection of facilities required to analyze,
12 process, store, and dispose of fluids produced from pyrolysis of oil shale kerogen. About 200 kW
13 of electrical power from the nearby power grid will be delivered to each of the two Electrofrac™
14 fractures to resistively heat the formation. Production wells will be placed appropriately to
15 collect hydrocarbons from the fractures. Approximately 40 barrels of oil per day, 350 thousand
16 standard cubic feet per day of gas, and 20 barrels of water per day are expected to be produced
17 during Phase II. Production is expected to begin soon after the onset of heating and continue for
18 6 months of active heating. Additional production is expected for a period of time after heating
19 stops.

20
21 *Phase III (Years 5–10)* will consist of a pilot level installation of the Electrofrac™
22 technology at depth. The pilot will consist of two Electrofrac™ fractures constructed at or near
23 the anticipated size and spacing required for commercial development. The goal of this phase is
24 to collect the information needed to determine the overall commercial viability of the
25 Electrofrac™ process: hydrocarbon recovery, sodium mineral recovery, environmental
26 acceptability, and economic viability. The anticipated number of wells and holes is somewhat
27 greater than those used in Phase II to serve larger fractures. The site of the Phase III tests would
28 be near the site used in Phases I and II.

29
30 Approximately 4 MW of electrical power from the nearby power grid will be delivered to
31 each of the two Electrofrac™ fractures to resistively heat the formation. Phase III operation is
32 expected to produce peak rates of approximately 400 to 700 barrels of oil per day, 1 to 6 million
33 standard cubic feet per day of gas, and 200 to 300 barrels of water per day. The pilot will be
34 operated for approximately 5 years.

35
36 During construction of wells and facilities, peak employment may be 120 workers.
37 Construction will involve a maximum of 30 vehicles per day going to and from the site
38 (10 commercial trucks and 20 passenger vehicles). During ongoing operations, total staff may
39 be as large as 20 workers, estimated to make a total of five to ten vehicle round-trips per day.
40 Operations workers will likely be housed in hotels (if nonresidents) or in typical residential
41 housing in Rifle, Meeker, Rangely, Silt, Parachute, or Grand Junction, Colorado.

42
43 Water will be needed for construction and drilling activities, shale oil processing, dust
44 control, testing the recovery of sodium minerals, and if necessary, used to mitigate groundwater
45 contamination, if any. Water required for drilling, fracturing, and dust control is estimated to
46 be 0.1–0.2 barrel of water per barrel of oil. Phase III efforts will better define water needs for

1 commercial in situ oil shale development and may identify opportunities to reduce water use.
2 ExxonMobil's mitigation strategy to protect proximate groundwater (and by extension, the
3 surface water streams in communication with groundwater) will be to design the operations to
4 contain the Electrofrac™ zone in a low-permeability envelope of unheated oil shale.
5

6 The effectiveness of this mitigation strategy will be evaluated throughout research
7 operations with a comprehensive Groundwater Monitoring Program. Up to 48 groundwater
8 monitoring wells will be completed in overlying and possibly underlying hydrologic units, both
9 upstream and downstream of the Electrofrac™ site. The Groundwater Monitoring Program will
10 begin 15 months prior to the start of pyrolysis operations to obtain baseline data on groundwater
11 quality.
12

13 Similarly, a comprehensive Surface Water Monitoring Plan will be developed prior to the
14 start of operations (and in parallel to the development of the Groundwater Monitoring Program)
15 to detect potential contaminants migrating from the pyrolysis zone. The Surface Water
16 Monitoring Plan will be implemented approximately 15 months prior to beginning the pyrolysis
17 operations and will include, at a minimum, four sampling locations: two in Ryan Gulch and two
18 in Yellow Creek, one upstream and one downstream of operations in each creek.
19
20

21 **A.5.3.6 Natural Soda**

22
23 Natural Soda Holdings, Inc. (NSHI) also submitted a proposal for an RD&D project in
24 2010 in response to BLM's second round solicitation. The project would employ in situ
25 technologies to extract kerogen from below ground and would be located on 160 acres
26 immediately east of ExxonMobil's proposed RD&D projects in the Piceance Basin in Colorado,
27 as shown in Figure A-9. The proposed RD&D lease abuts the southern boundary of Natural
28 Soda's existing federal sodium lease area. The following discussion is based on information in
29 the Plan of Operation for of the proposed project (Natural Soda 2011).
30

31 NSHI's proposed process of extracting kerogen uses high-temperature supercritical or
32 near supercritical water in conjunction with carbon monoxide, sodium bicarbonate, and sodium
33 aluminate to break down and liquefy kerogen. NSHI has operated a sodium bicarbonate
34 (nahcolite) solution mining operation in the Piceance Basin for over 18 years. The company will
35 apply its expertise in solution mining in the proposed in situ oil shale recovery project.
36

37 Experience has shown that sodium bicarbonate and sodium aluminate catalyze the liquid
38 forming reactions of Victorian brown coal in the presence of carbon monoxide and water. The
39 proposed project will test whether these same reactions work in oil shale. Naturally occurring
40 Dawsonite ($\text{NaAlCO}_3(\text{OH}_2)$) in the saline zone of the Piceance Creek Basin is chemically
41 similar to sodium aluminate (NaAlO_2) and breaks down at temperatures in the range of kerogen
42 decomposition, providing the opportunity to develop an in situ kerogen liquefaction process.
43

44 The ultimate scale of the project will depend on the initial results of a small-scale effort
45 involving a single Oil Shale Reactor (OSR) production well. The OSR will be drilled in 40-ft
46 intervals at the base of a saline zone that has the potential to produce 100 bbl of oil shale.

1 Additional intervals will be installed at higher levels in the saline zone. Based on the results of
2 this initial production well, additional production and monitoring wells will be placed within the
3 160-acre lease area.
4

5 The NSHI process would utilize the natural presence and distribution of sodium minerals
6 for both the generation of porosity and permeability and potentially, to catalyze the conversion of
7 kerogen to a liquid product. No fracturing methods will be employed, but minor fracturing might
8 occur as a result of thermal expansion of the oil shale. Nahcolite produced in the pilot well will
9 be tested at NSHI's existing sodium bicarbonate processing facility. If the solution product is not
10 rich enough for recovery, it will be added to the barren liquor stream of that process, thus
11 preventing the production of a new waste stream from the proposed project.
12

13 Groundwater impacts will be controlled by working in the lower part of the saline zone in
14 the upper Green River Formation, which is devoid of groundwater. Nahcolite would be solution-
15 mined prior to the conversion of kerogen, thus utilizing this resource fully. NSHI's existing
16 solution mining facilities, as well as supporting roads, electricity, water, and natural gas facilities
17 would be used, thus reducing soil and other disturbance from construction of the project.
18

19 An estimated 10–20 workers would be employed during the drilling and construction
20 phase of the project, and 5–10 workers during operations. Drilling would start no later than 2014.
21 Production would start about three months after completion of the production well and would
22 continue until the success of the conversion technology and commercial viability of the process
23 can be established.
24
25

26 **A.5.3.7 Red Leaf Resources**

27

28 Red Leaf Resources, incorporated in 2006, has developed the EcoShale™ In-Capsule
29 Technology to produce liquid transportation fuels from oil shale, oil sands, coal, lignite and
30 bio-mass. The resultant product is a high-quality feedstock with no fines. The process also
31 produces synthetic natural gas, which can be used as an energy source for the process. The
32 following summary is based on information on Red Leaf's Web site (Red Leaf Resources, Inc.
33 undated).
34

35 Red Leaf Resources holds 18 mineral leases for approximately 17,000 acres of state-
36 owned and -managed school trust lands in the Uintah Basin, including some of the best
37 surface-mineable and richest oil shale in the United States. Average overburden thickness is
38 approximately 60 ft, with a resource seam at least equivalent. Estimates indicate approximately
39 1.5 billion barrels of oil equivalent in-place on the Red Leaf leaseholds.
40

41 The EcoShale™ In-Capsule Technology involves heating surface-mined shale in a
42 closed, clay-lined, surface impoundment, or capsule. The process relies on conventional mining
43 and construction methods and produces a bottomless oil product that requires no coking. The
44 process produces a shale oil with a much higher concentration of middle distillate than West
45 Texas intermediate crude. Two synthetic shale oil products are produced: (1) prompt oil of
46 approximately 29 API gravity and (2) condensate oil of approximately 39 API gravity. The oil

1 and condensate produced with this process have no fines and have very low acid numbers. The
2 technology requires no process water.

3
4 *Pilot Test.* A test of the EcoShale™ In-Capsule technology was carried out in the Uintah
5 Basin in Utah in 2009. The field test pilot validated the technology modeling and engineering
6 design aspects. The process produced a high quality product with a prompt oil that was
7 approximately 29 API gravity, about 65% paraffin + naphtha, and about 12.6% hydrogen. A
8 condensate liquid was also produced with an approximate 39 API gravity, about 55% paraffin +
9 naphtha, and about 12.9% hydrogen. Sulfur content was approximately 2,200 ppm and nitrogen
10 content was about 1–1.2 wt%. The oil produced contained almost no entrained solid fines from
11 the shale ore. Capsules (or, impoundments), which contain the hydrocarbon treatment zone,
12 would be scalable from smaller impoundments that produce a few hundred barrels per day, to
13 very large impoundments that produce thousands of barrels per day.

14
15 *Economics.* According to the company, the EcoShale™ In-Capsule Technology has an
16 estimated Energy Return on Investment (EROI) of 10. This is, for every unit of energy that is
17 used to heat the process, an estimated 10 units of energy are produced, thus making the EROI
18 comparable to that of conventional oil. This EROI has been validated by bench-scale and field
19 test performance. A process production cost of \$25/bbl is estimated, depending on the project
20 scale implemented and the specific resource geology.

21
22 The EcoShale™ In-Capsule Technology is largely energy self-sufficient, as it produces
23 enough synthetic natural gas to meet all of its power, heat, and hydrogen requirements. Red Leaf
24 Resources envisions using produced synthetic natural gas for all of its power requirements.

25
26 Red Leaf has indicated that the company is ready to begin building a mine and a
27 processing facility in the Uinta Basin in 2012, with plans to produce 9,500 barrels of oil per day
28 by 2014 (Hanson 2011).

30 31 **A.6 REFERENCES**

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33 *Note to Reader:* This list of references identifies Web pages and associated URLs where
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ATTACHMENT A1:
ANTICIPATED REFINERY MARKET RESPONSE
TO FUTURE OIL SHALE PRODUCTION

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ATTACHMENT A1:**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

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

- 3
- 4 • Intuitively, domestic sources of crude shale oil are more desirable than foreign
5 sources of crude oil simply because of their inherently more secure status.
6 However, to retain their advantage, such domestic sources must also compare
7 favorably with imported feedstocks with respect to overall product yield and
8 other quality parameters (e.g., high-sulfur, high-acid content). Crude shale oil
9 has great potential for replacing equivalent amounts of imported crude oil
10 with comparable quality factors.
 - 11
 - 12 • Of the imported crude sources likely to be displaced by crude shale oil, the
13 most likely are those currently being delivered to refiners in the Midwest and
14 Gulf Coast, the two geographic areas composing the largest and most flexible
15 markets for crude. Imported crude oil supplies most similar in quality to crude
16 shale oil would be the first to be replaced since that replacement would
17 require little to no change in refining capability.
 - 18
 - 19 • Pipelines do not drive refinery market investments; pipeline operators react to
20 committed emerging markets and provide transportation linkage between the
21 source and the refiner.³²
- 22

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

37

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

43

³² 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.

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

7
8 This paper reviews some of these issues to identify the inherent drivers in the
9 marketplace that could show the likely market placement of increased production of U.S. crude
10 shale oil. The relatively recent entry of Canadian syncrude and bitumen into the U.S. refinery
11 market provides a good example of how U.S. oil shale production might enter the refining
12 market.³³ Volumetrically, the amount of Canadian syncrude and bitumen currently entering the
13 U.S. market is of the same general order of magnitude as an estimate of anticipated commercial
14 production levels for U.S. oil shale facilities (i.e., about 2 million bbl/day).³⁴ The Canadian
15 crude experience can help define logistical infrastructure changes, the economic factors that
16 control inflow into existing refining centers, the probability of refinery expansions, and the
17 possible crude sources that may be displaced. It is important to note, however, that recent trends
18 in refining demand for Canadian crude are economically favoring the nonupgraded raw bitumen,
19 which is sold at a substantial discount, thus providing the refiners with more margin potential.
20 This ultraheavy bitumen is analogous to other foreign heavy crudes, which are in abundant
21 supply in the marketplace and are also sold at a steep discount. The increased utilization of these
22 ultraheavy crudes has required extensive investments in the “bottom-of-the-barrel processing”
23 coker capacities. The shale oil and upgraded synthetic portions of Canadian crude have very little
24 “bottoms” or residual; therefore, not only can they be processed in refineries without significant
25 capital investment, they can serve as a complementary blending component with the ultraheavy
26 crudes to balance the overall feedstock pool to the refinery. They must be produced, however, at
27 an economically attractive price to compete with these steeply discounted heavy crudes

30 2 OVERVIEW OF THE CRITICAL PARAMETERS 31 IN THE CRUDE OIL REFINERY PROCESS

32
33
34 Crude oil is a mixture of hydrocarbons formed from organic matter. It varies in chemical
35 and physical composition, including differences in sulfur content, typically small amounts of
36 nitrogen, acidity, density, etc. At the most fundamental level, the refining process involves
37 actions in any of the following categories:

- 38 • Separation—Distillation,

39
40

³³ 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.

³⁴ 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.

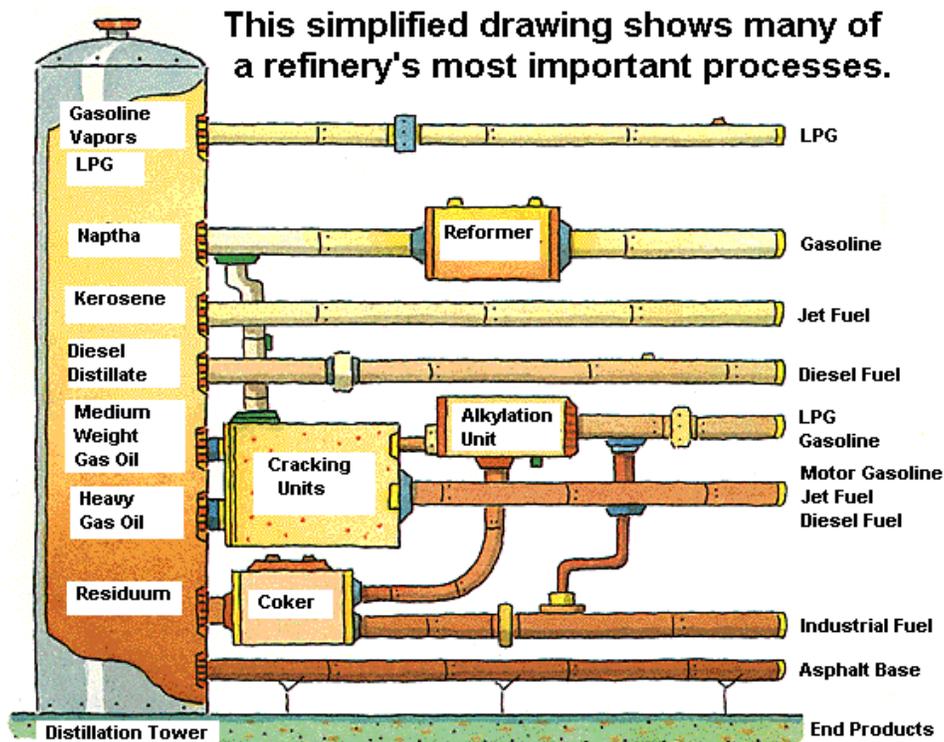


FIGURE 1 Generic Refinery Configuration (Source: EIA 2006a)
(LPG stands for liquefied petroleum gas.)^a

^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.

1 Crude oil sources are typically classified by density. By industry
 2 convention, density is expressed as American Petroleum
 3 Institute (API) gravity: light (API >34), medium (API 26–24), or
 4 heavy (API < 24).³⁵ Density, in turn, is reflective of fundamental
 5 differences in underlying chemical compositions. The lighter the
 6 crude source, the greater the relative percentage of small- to
 7 moderate-sized organic molecules with high degrees of
 8 saturation, making it more amenable to conversion into high-
 9 value products such as gasoline and other low-boiling fuels and
 10 products. Heavier crude will have greater relative concentrations
 11 of heavier components with higher degrees of unsaturation. Such
 12 compositions lend themselves more readily to conversion into
 13 heavier distillate products such as various grades of fuel oils,
 14 lubricating oils, asphalts, and similar products, as shown in
 15 Figure 2.

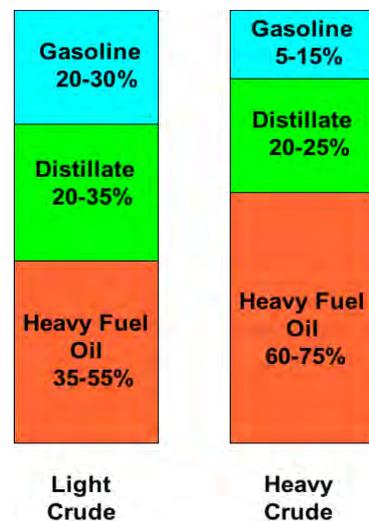


FIGURE 2 Comparison of Conversion Products Based on Crude Composition (Adapted from Day 2005)

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

32
 33 As the above discussion suggests, many factors ultimately determine the extent of crude
 34 shale oil's penetration into the existing petroleum refinery market; however, the crude shale oil's
 35 overall quality (chemical composition as well as critical physical properties) would be the
 36 primary factor on which refineries base their decisions to pursue shale oil feedstocks.
 37 Unfortunately, the quality of crude shale oil produced at commercial scale is currently one of the
 38 areas of greatest uncertainty. Empirical evidence suggests that, together with the intrinsic
 39 variability in the composition of the parent oil shale, the quality of recovered shale oil ultimately
 40 offered to the refinery market will be highly dependent on the extraction and retorting
 41 technologies selected and the nature and extent of mine site upgrading. That being said, there is

³⁵ 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.

1 very little experience related to commercial-scale shale oil development.³⁶ The newest in situ
2 retorting technologies undergoing R&D hold the promise of recovered shale oil of exceptional
3 quality. (For example, Shell Oil anticipates that its in situ heating/retorting technology may yield
4 crude shale oil of roughly 30% fractions each of raw naphtha, jet fuel, and diesel fuel and 10%
5 residual. Shell further believes that relatively minor adjustments to field conditions could allow a
6 change in composition of recovered product in response to extant refinery market conditions.) At
7 this point in time, however, neither legacy technologies nor cutting edge technologies have
8 amassed sufficient evidence on which to safely predict the quality factors that would result from
9 their implementation at commercial scales. Long-term reliability of quality factors is absolutely
10 critical to refinery acceptance, more so than the absolute values of those quality factors.
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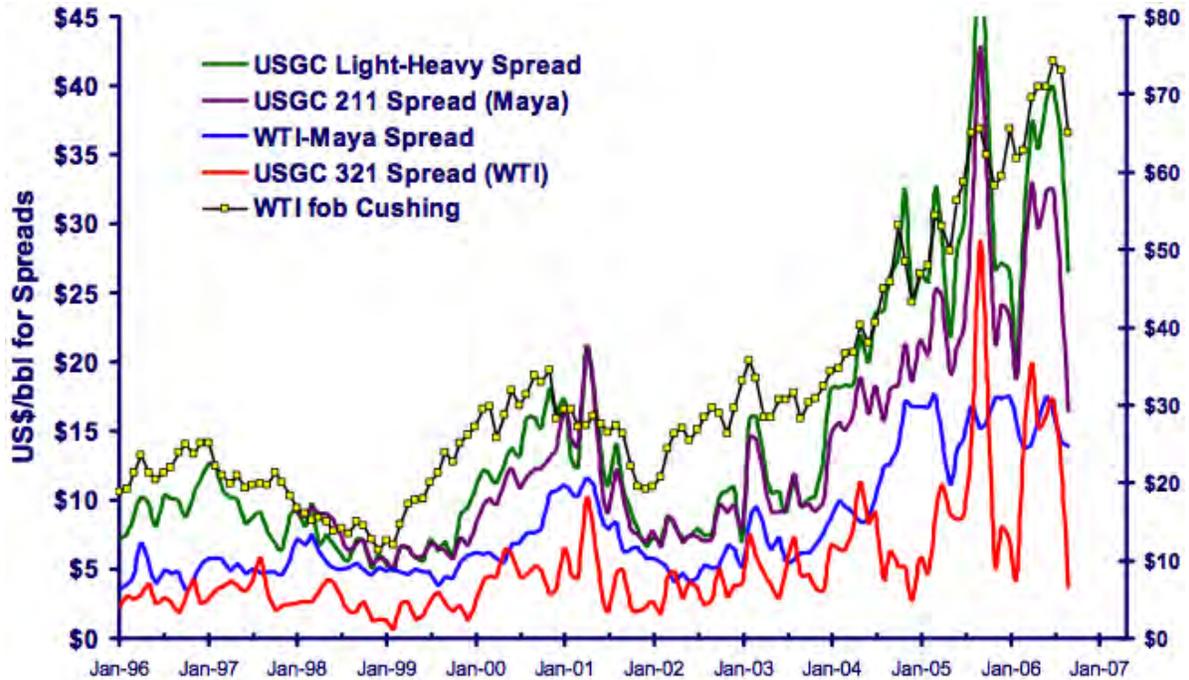
13 **3 MARKET RESPONSES TO FEEDSTOCK VALUE PARAMETERS**

14
15

16 Because heavier crude sources produce fewer high-value products, or produce higher-
17 value products only with additional processing costs, markets compensate by trading heavier
18 crude at a price discount relative to lighter crude. Heavier crude stocks are further discounted to
19 offset the higher processing costs of using cokers to convert this low-value residual into higher-
20 value gasoline and distillate components rather than less valuable heating fuels and asphalts,
21 lubricating oils, and road oils. Transportation fuels (e.g., gasoline and distillates) are the highest
22 demanded products. Without upgrading capacity, there would be an excess of fuel oils and
23 asphalts, and refiners would process lighter crudes rather than the economically desirable heavier
24 crude. Figure 3 shows the refining margins associated with processing light and heavy crudes.
25 The green line highlighted at the top represents the difference between processing the benchmark
26 light (e.g., West Texas Intermediate) and heavy (Mexican Maya) crudes. As can be seen on the
27 left axis, this reached a peak of an approximately \$40 per barrel advantage of heavy crude over
28 light crude this year. The Canadian crudes referenced in this paper are in the heavy category.
29 While the expected composition of U.S. crude shale oil is not known precisely, it will probably
30 be more comparable to the light crude in value than to the heavier crude stocks now available on
31 the market. Mine site upgrading could further improve this equivalency.
32

33 The second element critical to the desirability of crude oil supplies is sulfur content. New
34 specifications on gasoline and diesel are increasingly requiring lower and lower sulfur content.
35 Sellers of high-sulfur crudes have to discount them enough to account for the required sulfur
36 extraction process in the refinery. From a sulfur content perspective, some U.S. shale oil
37 products could be more attractive than conventional domestic crudes and Canadian imports.
38 Green River oil shale sulfur content ranges from 0.46 to 1.1% (by weight), approximately 30%
39 organic sulfur compounds, with sulfur content increasing as the richness of oil shale deposits
40 increase.
41

³⁶ 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.



1
2 **FIGURE 3 Heavy vs. Light Crude Refining Margins (Source: Arnold 2006)**

3
4
5 Because of the high investment capital required to modify a refinery to process heavy
6 crudes, refiners electing to do this have typically signed 7- to 10-year crude supply agreements.
7 These long-term crude supply agreements shrink the near-term market available for heavy crude
8 displacement by new crude shale oil supplies.
9

10 Given the uncertainty of quality factors that can be expected for commercially developed
11 shale oil, it is difficult for refinery operators to determine the relative attractiveness of future
12 crude shale oil sources against currently available sources. Frequently, operational adjustments
13 and sometimes equipment investments have to be made to adapt to a significant change in a
14 crude oil source. This could be related to process upgrading, impurity removal, or
15 accommodation of other metallurgy, heating, cooling, or pumping capacities. Even without
16 major structural changes, the normal unit variations created with introductions of new sources
17 typically result in a refinery repeatedly testing small volumes of a new feedstock over a period of
18 time to better understand the impacts on operations. Until long-term quality factors are
19 established for crude shale oil, it is reasonable to expect a lag between initial commercialization
20 of oil shale facilities and the development of refineries to accept it. Such an initial lag may be
21 shortened to some extent by interim decisions on the part of refineries to accept crude shale oils
22 of lesser quality with the intent of blending them with existing stocks to produce averaged
23 quality factors in the blend that can still be managed economically in existing refining units with
24 little to no modifications.
25

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

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

9
10 However, given that shale oil production sites will be located in generally arid or
11 semiarid regions with limited sources of power, fuel, and water for processing, extensive
12 treatment and upgrading of crude shale oil could be limited in the early years of industry
13 development by the availability and costs of required resources and may, therefore, occur only to
14 the extent necessary for safe and economical pipeline transport to an off-site refinery. Should this
15 be the case, early market penetration of shale oil would more likely be the result of the pursuit of
16 blending options rather than displacement of high-value conventional crude feedstocks.

17 18 19 **4 REFINERY UTILIZATION FACTORS** 20 21

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

33
34 BSD represents the absolute maximum rate at which a unit can operate during any single
35 day. This rate is a function of unit design and the capacity of supporting systems but cannot be
36 sustained for extended periods of time.

37
38 BCD represents the maximum rate of production a unit can sustain over the course of a
39 year given maintenance downtime and operating limits due to varying feed qualities. As such,
40 the BCD value is the only reliable representation of a refinery’s long-term production capacity.

41
42 The differences between BSD and BCD are unique for each refinery and reflect the types
43 and ages of individual refining units and their respective repair and maintenance demands. The
44 quality of the incoming feedstock also affects the difference between BSD and BCD capacities,
45 since the amounts and types of impurities that must be removed during processing can greatly
46 affect maintenance and overhaul schedules of individual units. Such factors explain the reported

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

7
8 The difference between BCD and BSD, or between either rate and 100%, does not reflect
9 spare capacity that can be utilized when desired to accommodate a new feedstock source,
10 however. Unless otherwise specified, refinery capacities referenced in the remainder of this
11 analysis mean BCD.

14 **5 CURRENT STATE OF PETROLEUM REFINING IN THE UNITED STATES**

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16
17 The 149 operable refineries in the United States range in size from very small and
18 specialized individual processing units with a capacity of 1,500 BCD, to large integrated
19 refineries with capacities exceeding 550,000 BCD.

20
21 For the purpose of data collection, refineries are arranged in geographic regions known as
22 Petroleum Administration for Defense Districts (PADDs). This system of categorization dates
23 back to World War II and was devised to administer the distribution of petroleum products.
24 PADDs also reflect the natural boundaries and flows of petroleum feedstocks and refined
25 products. Figure 4 shows the geographic boundaries of the PADDs.³⁷

26
27 Figure 5 shows the histograms of refinery sizes by PADD. PADD 4—Rockies has a
28 disproportionate number of small refineries in comparison with the other PADDs, and these
29 small refineries only serve regionally local markets and are configured to produce a limited array
30 of products. The PADD 4 refineries originally were almost exclusively supplied with
31 domestically produced crude from fields within the PADD. Now, additional pipeline investments
32 have been made, bringing Canadian crude into the region. In most cases, additional upgrading
33 capacity was added at the refineries to process the heavier Canadian crude. A relatively high
34 sulfur concentration characterizes the remaining domestic crude production in the region. Key
35 producing states in PADD 4, such as Wyoming and Montana, currently have an excess capacity
36 of domestic crude production. In addition to pipeline logistical constraints, the consistent
37 expanding price differential between light crude over heavy crude has kept this domestic
38 production of light crude noncompetitive outside of this region. This was the first market with
39 logistical connections with Canada and was the first market penetrated by Canada, although in
40 relatively small volumes compared with Canada's current production.

41
42

³⁷ 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

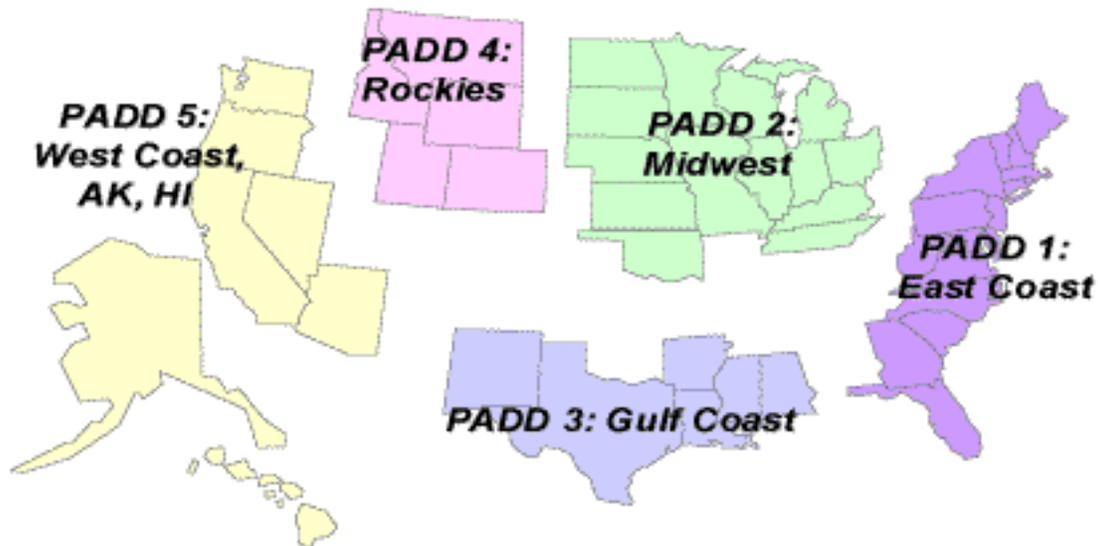


FIGURE 4 Petroleum Administration for Defense Districts Map (Source: EIA 2006b)

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 BSD in 1986 to 16.9 million BSD 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

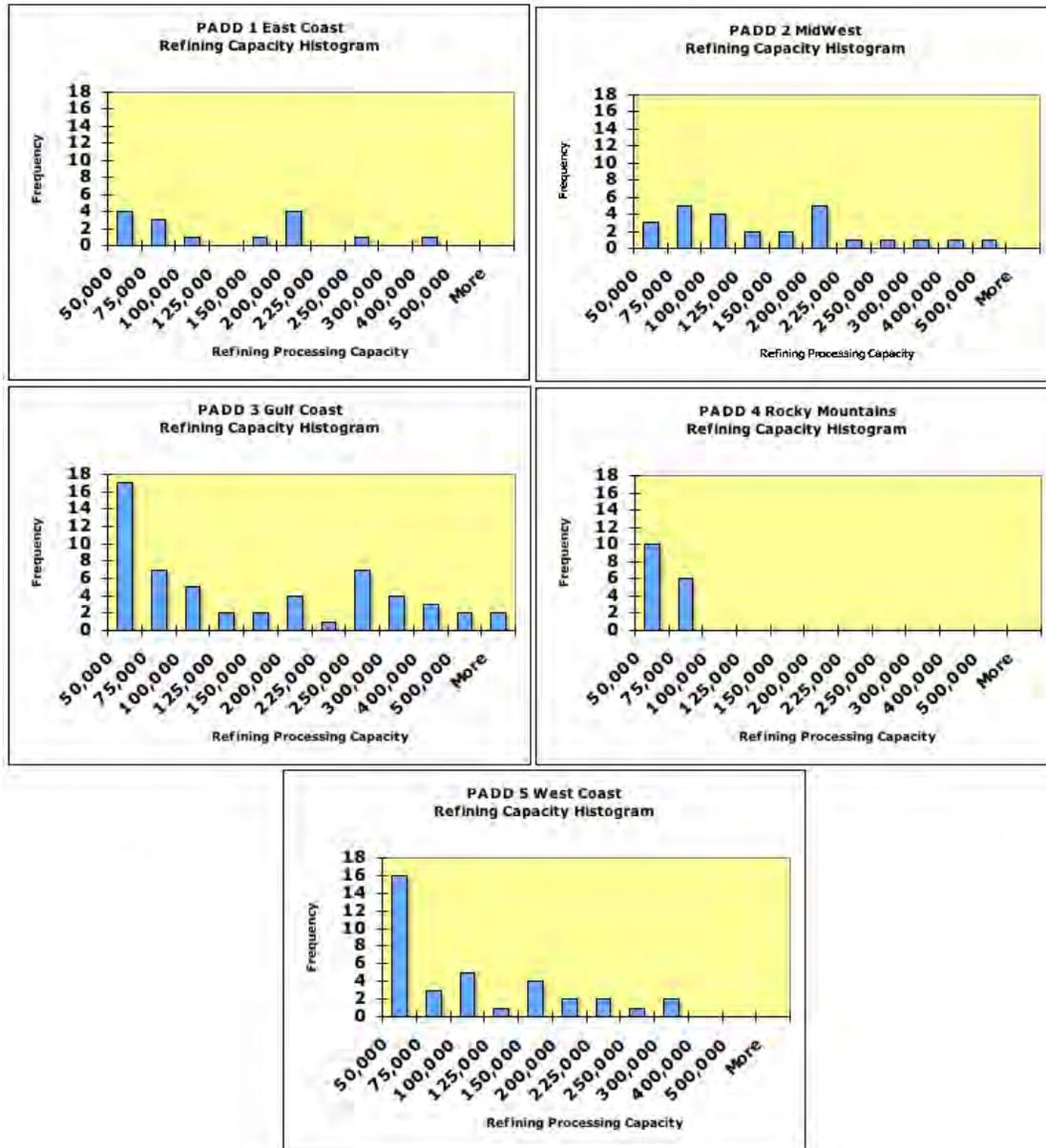
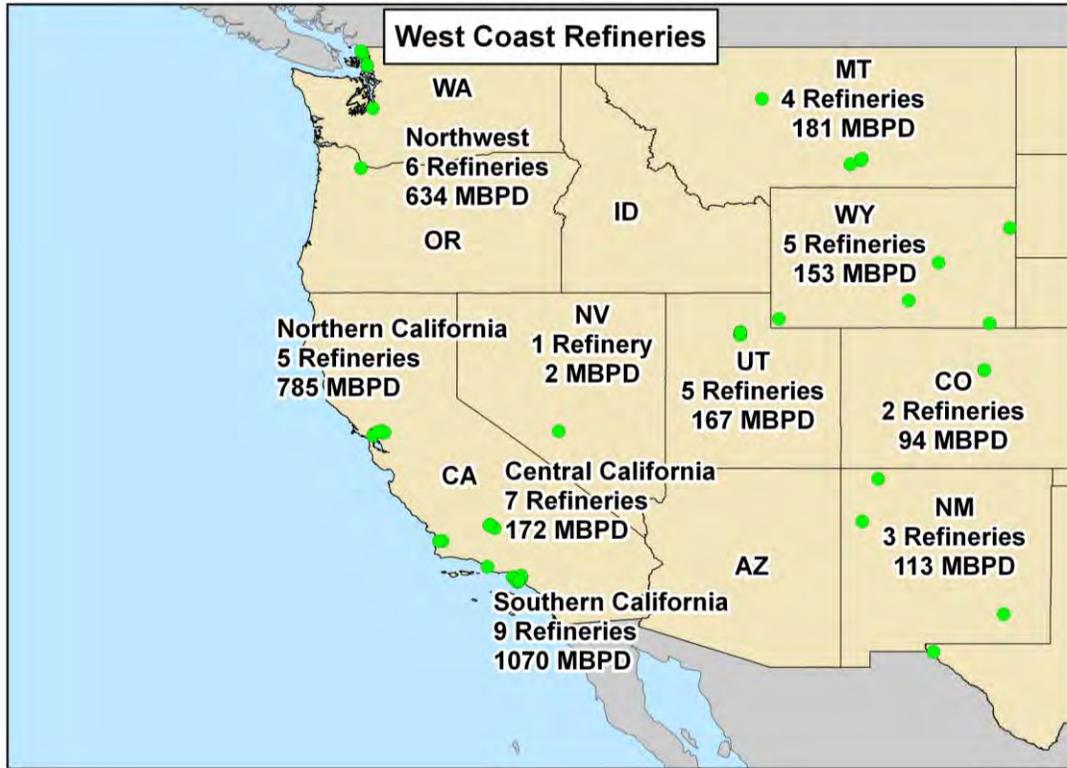


FIGURE 5 Distribution of Refining Capacities (Source: EIA 2006c)

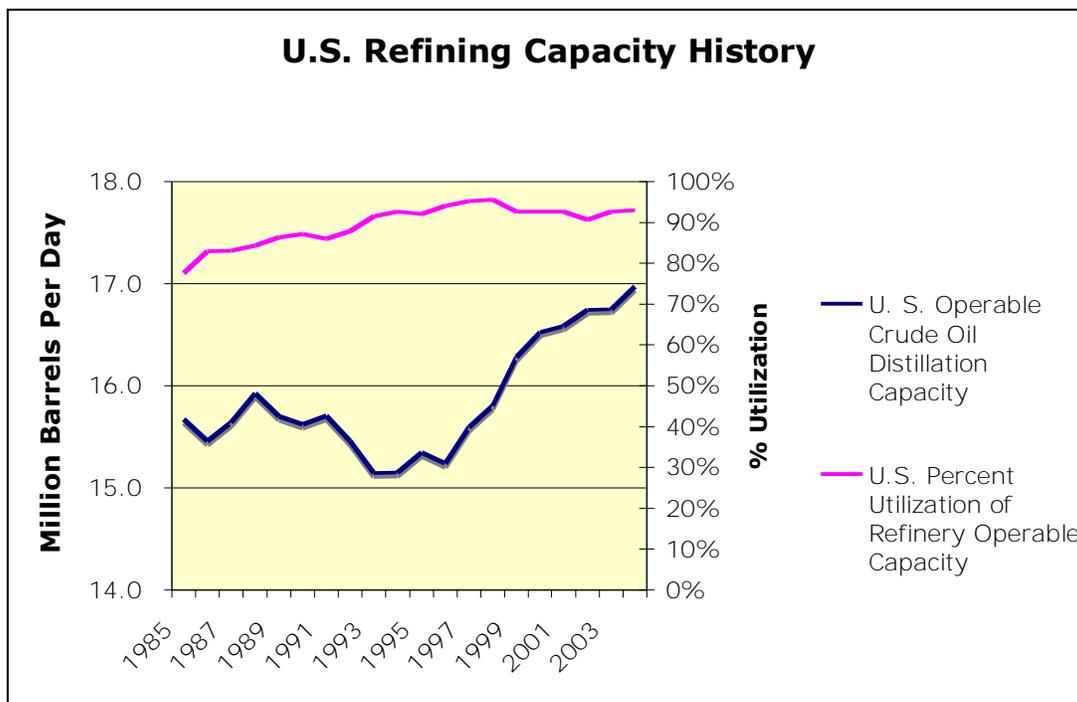
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have spent approximately \$47 billion (Slaughter 2005) to reduce sulfur levels in transportation fuels and to comply with 14 new environmental regulations that come into place this decade (Wall Street Journal 2004). Of the 60 refinery expansion projects 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



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



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

1 are not expected to change substantially.³⁸ However, refinery expansion is a continuous process
2 of capital project evaluation, so it does not represent a true forecast for refinery capacity.
3 Because of the industry's tendency to expand existing assets, initial new market growth for shale
4 crude oil is most likely to be at existing areas of refining concentration.
5

6 U.S. demand for refined products has grown steadily, and growth is expected to continue
7 into the foreseeable future. Similarly, increased refining capacity has followed a parallel growth
8 path to meet the rising demand. Current margins and announced refinery projects suggest that
9 refinery growth will continue into the foreseeable future. The distinction of whether or not such
10 growth occurs at a new location or whether it comes through expansion of existing facilities is
11 not critical in evaluating the foreseeable potential of crude shale oil. If the market drives the
12 crude shale oil to be delivered to the Gulf Coast, expansion of existing large refinery facilities
13 to take advantage of associated economies of scale would be the probable response. If a new
14 facility was constructed to take specific advantage of crude shale oil economics and logistical
15 availability, it would not necessarily be located within the immediate vicinity of the crude shale
16 oil sources. Ultimately, increase in refining capacity, whether through expansions or new
17 facilities, will occur to the extent necessary to serve the ultimate markets for the end products.
18 Whether the crude shale oil is transported to existing refining centers for processing or whether a
19 new facility is constructed to refine the crude closer to the point of production is a function of
20 economics and market balance and is not an inherent constraint on the viability of crude shale oil
21 production. In either scenario, there is a positive realization of the crude shale oil market and an
22 associated environmental impact wherever refinery expansion occurs.
23

24 Refinery expansion occurs to profitably meet growing demand. Feedstock selection is a
25 secondary process of optimizing refinery economics. Given the complexity of the dynamics of
26 meeting increasing refinery demand and/or displacing existing crude supplies, attribution of
27 refinery expansion to the introduction of crude shale oil is difficult. A further complication arises
28 with the realization that over a period of as long as 20 years, production rates of some current
29 feedstock sources may fall dramatically, therefore "freeing up" refining capacity without the
30 need for refinery expansions.
31

32 **6 CURRENT CRUDE SOURCES**

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36 Any new crude source has to find a market in either expanded refinery production or by
37 competitively displacing other crude supplies in the market (including through the adoption of
38 feedstock blending strategies by refineries). This section describes the existing sources of crude
39 feedstock that are supplying U.S. refineries.
40

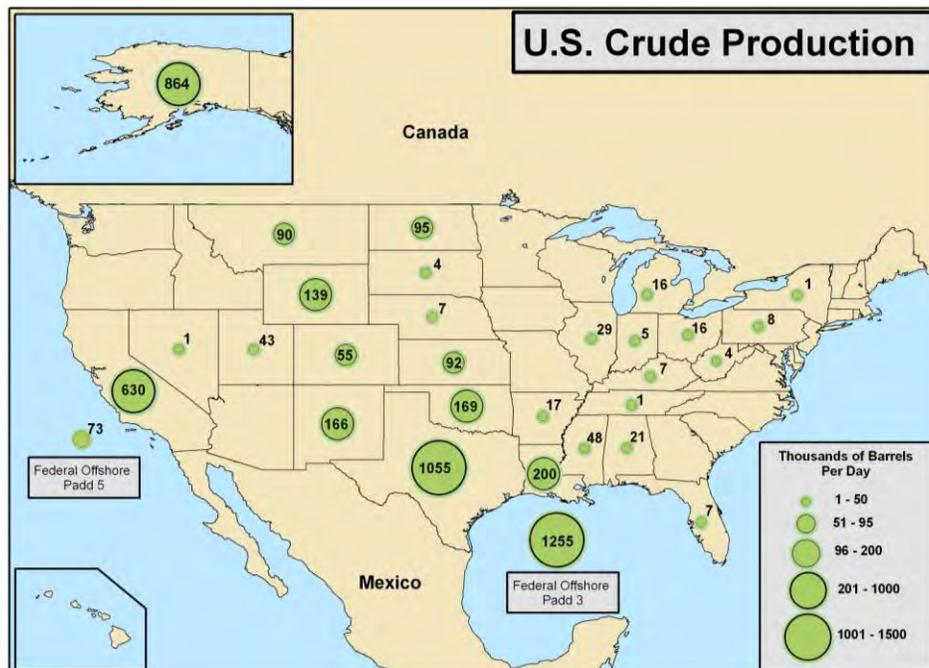
41 In 2005, the United States processed 15.8 million bbl of crude per day. Of this,
42 2.4 million bbl/day comes from domestic production, 2.1 million bbl/day is imported from

³⁸ 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.

1 Canada, and 11.3 million bbl/day comes from other international sources. Crude is produced
 2 domestically in 28 states and in state and federal offshore waters on the West Coast and the Gulf
 3 of Mexico. Figure 8 shows domestic production by state.
 4

5 The most likely market for new domestic crude sources is the displacement of
 6 comparable foreign crude. Figure 9 shows the percent of crude processed in each state that is
 7 imported as well as the volume that percentage represents. States in the extreme North and some
 8 in the Midwest are processing Canadian imports, which are less likely to be displaced because of
 9 the capital investment in upgrading already made or committed to by refineries to process these
 10 heavy crude supplies. The Canadian producers are developing crude pipelines to the Gulf Coast
 11 and are looking to the Gulf Coast PADD as their next incremental market. Any substantial shale
 12 oil production would likely follow this same market pattern. Summary information describing
 13 each of the PADDs is provided below:
 14

- 15 • PADD 1—East Coast has primarily waterborne crude receipts. It is net short
 16 of refining capacity and is a large importer of refined products from within the
 17 United States and internationally. It is the least likely market for crude shale
 18 oil. It receives refined products through the Colonial and Plantation pipelines
 19 and refined imports from the Caribbean and Europe.
 20
- 21 • PADD 2—Midwest is geographically constrained from the primarily
 22 waterborne receipts in the Gulf Coast and offshore domestic Gulf Coast
 23 production. Its access via crude pipelines from the Gulf adds additional
 24 expense. Therefore, it was a natural secondary market for Canadian
 25
 26



27
 28 **FIGURE 8 Domestic Crude Production (Source: EIA 2006e)**

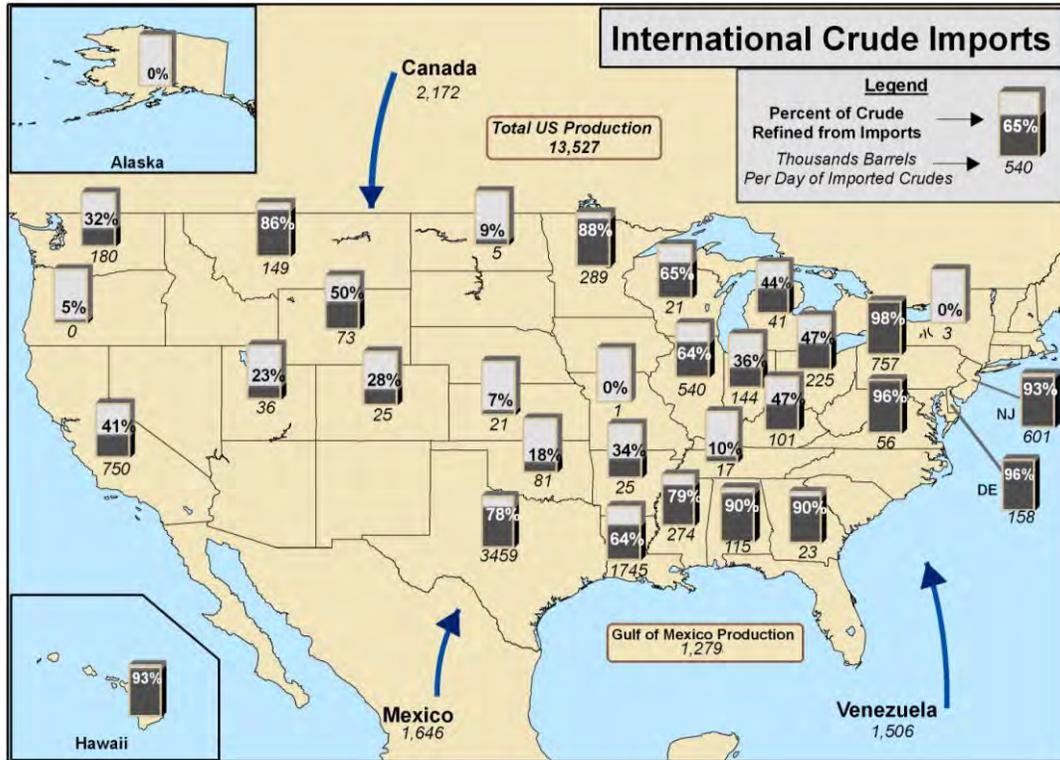


FIGURE 9 International Crude Imports (Source: EIA 2007)

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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

1 readily available, such as in the Gulf Coast, then a refiner has to be less
2 concerned with balancing the composition of the crude with the individual
3 unit capacities. The refiner can sell or purchase additional intermediates to
4 make up for crude mismatch. The extensive number of petrochemical plants
5 within the immediate vicinity of PADD 3 refineries further expands market
6 flexibility for secondary feedstocks. This makes a much more competitive
7 crude environment and lowers the premium on crude qualities, since there is
8 more freedom to correct poor-quality feeds. The Gulf Coast also was the
9 original recipient of foreign heavy crude and, therefore, has extensive
10 upgrading and sulfur extraction processing capacity for these supplies. Having
11 access to a wide variety of world crude supplies, these refiners present a more
12 competitive landscape for producers of crude oil and also establish a lower
13 barrier to market entry for any feedstock that has differentiating economics.
14 Pipeline reversals and new pipeline construction are underway to transport
15 Canadian crudes to PADD 3. The large market is certainly an alternative for
16 larger volumes of shale oil but, again, is the most competitive on price.

17

- 18 • PADD 4—Rockies is the region in which crude shale oil would be produced.
19 Its refineries are relatively smaller than those in other PADDs. Its crude
20 market is primarily domestic light sour production and imported Canadian
21 crude. Canadian crude imports have increased substantially. It was one of the
22 first markets to be exploited by Canada until further logistical capacity could
23 be built to the Midwest and then later connections could be made with other
24 pipelines to the Gulf Coast. The markets for the refined products are also very
25 localized, with the exception of the product pipeline from Salt Lake City,
26 Utah, to eastern Washington and Oregon. Environmental considerations, such
27 as water availability, could be a larger issue to refinery expansion in PADD 4
28 than in other PADDs. PADD 4 refineries are implementing improved
29 wastewater recovery and water conservation projects in existing refineries in
30 this region. PADD 4 would be the most likely early adopter, and refineries
31 would be available with little pipeline capacity increase, but, collectively,
32 refineries in this PADD are very limited in the total volume of new feedstock
33 that they can accept. Full realization of the shale oil potential will require
34 significant displacement of current crude sources to PADD 4 refineries or
35 crude shale oil sales in other PADDs.

36

- 37 • PADD 5—West Coast is a complex but isolated market. The product
38 requirements of the California Air Resources Board (CARB) are very
39 challenging for refiners. Access to European and Gulf Coast products is
40 constrained logistically by the transit time and ship availability to transit the
41 Panama Canal (including the size limitation imposed on ships by the Canal).
42 Even within the PADD, interchanges of supply and distribution are complex.
43 Many of the San Francisco area refiners cannot produce CARB-approved
44 gasoline and, therefore, export the entirety of their gasoline production to
45 Washington and Oregon. Washington refiners can make CARB-approved
46 gasolines and, therefore, produce for this higher-profit market segment and

1 supply gasoline to southern California, which is net short of all products.
2 Washington refiners produce some high-sulfur distillates, which exceed
3 U.S. specifications, and these distillates are exported to both Latin America
4 and South America. PADD 5 processes approximately two-thirds of domestic
5 crude, including Alaska North Slope crude. Both California and Alaskan
6 domestic crude sources are expected to decline within the 20-year time frame
7 for this shale oil forecast horizon. The Southern California refiners,
8 representing more than 1 million bbl/day of processing capacity, are
9 particularly short of crude, and any domestic declines will only increase their
10 disadvantage. While there are currently no crude pipelines to carry shale oil
11 crude from the Rocky Mountain area to the West Coast, PADD 5 represents a
12 sufficiently attractive market for consideration in that pipeline infrastructure
13 investments are likely over the long term.
14

15 7 CANADIAN CRUDE PRODUCTION

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18

19 Canada is one of the largest crude exporters into the United States and is becoming of
20 greater strategic importance given the increasing uncertainties associated with other foreign
21 crude sources. It is enlightening to review the history of Canadian syncrude oil's entry into the
22 U.S. refining market since this has been a relatively recent injection of a significant volume of
23 crude feedstock into the U.S. market and may be representative of the pathway that
24 U.S.-produced crude shale oil may follow. The source for the information presented in this
25 section is *Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006–2015*, published
26 in 2006 by the Alberta Energy and Utilities Board (EUB 2006).
27

28 The majority of Canadian syncrude is produced in Alberta Province, which is
29 geographically closest to and competes with Western U.S. crude production. Most syncrude is
30 now produced either by mining tar sands or by various in situ techniques using wells to extract
31 crude bitumen. The product is generally classified as "heavy crude." Raw bitumen production
32 has been increasing in recent years and accounts for more than 60% of Alberta's 1995 total crude
33 feedstock production. A large portion of Alberta's bitumen production is upgraded to syncrude.
34 Upgraders chemically add hydrogen to bitumen, subtract carbon from it, or both. In upgrading
35 processes, the sulfur contained in bitumen may be removed. Bitumen crude must be diluted with
36 some lighter viscosity product (called a diluent) in order to be transported in pipelines. Use of
37 heated and insulated pipelines can decrease the amount of diluent required; however, such
38 techniques are not feasible for transport over long distances.
39

40 Canada has accomplished a dramatic increase in overall crude production, and it is
41 forecasted to continue increasing at a large rate. Figure 10 shows the historical growth and
42 forecast of Canadian crude oil by source. At the rate of anticipated production growth displayed
43 in Figure 10, Canadian syncrude could represent a substantial percentage of total crude volume
44 consumed by U.S. refineries within the near future. For example, by 2015, a forecasted Canadian
45
46

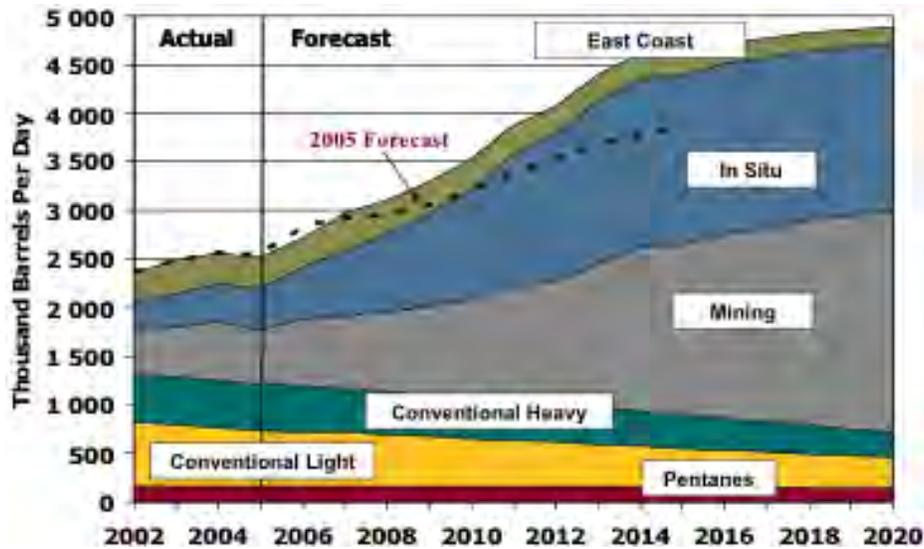


FIGURE 10 Canadian Crude Supply Forecast (Source: CAPP 2005)

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.³⁹

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 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

³⁹ 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).

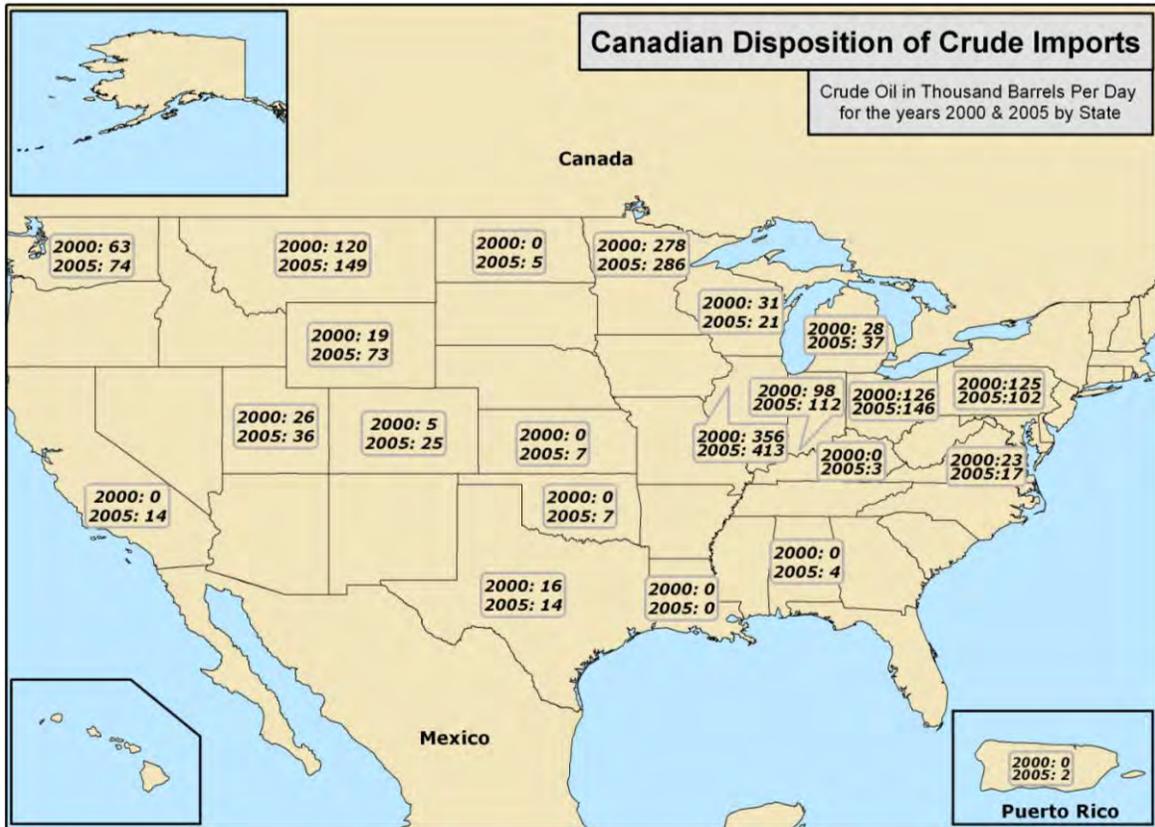


FIGURE 11 Canadian Crude Oil Disposition (Source: EIA 2007)

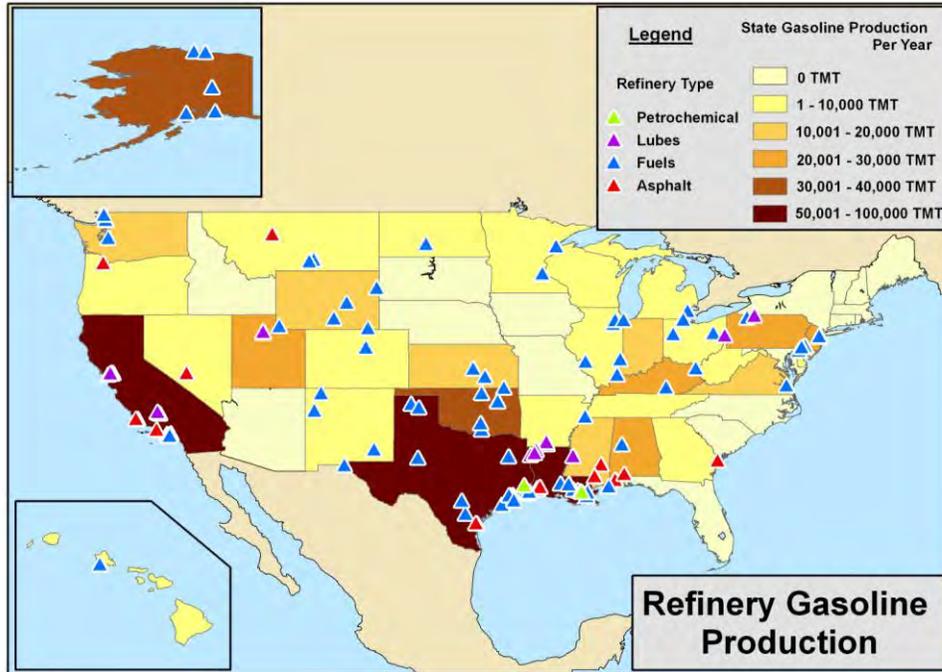
acceptance into refineries will not require incremental investment in heavy crude processing capacity.

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.

8 THE EVOLVING MARKET FOR SHALE OIL CRUDE

It is useful to consider the development of shale oil markets in phases. On the basis of historical precedent, in the early years of initial commercial production (1 to 5 years after the start of commercial development), there is likely to be a relatively small volume of shale oil available on the local commercial market, and this volume may be of varying quality as various



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



6
7
8

FIGURE 13 Canadian and U.S. Crude Oil Pipelines
(Source: CAPP 2005)

1 methods of shale oil recovery and processing are introduced, fine-tuned, and combined. In
2 addition, over this period, the shale oil producers may shift the degree to which they upgrade the
3 raw recovered crude shale oil to match evolving market conditions and to improve their market
4 penetration potential. If these initial volumes of commercial shale oil are differentiated
5 economically, they are most likely to find a market within PADD 4 to the extent allowed by
6 existing transportation infrastructure. As was noted earlier, there will likely be some hesitancy on
7 the part of refiners to use these crudes until their qualities are consistent and predictable.
8

9 In a second phase (probably in years 5 to 10), the volume of shale oil available will
10 have exhausted refiner's opportunities to displace existing feedstocks, saturate local refining
11 capacities, and exceed existing pipeline transport capacity within the immediate region. This
12 is likely to focus additional growth to either PADD 2—Midwest or PADD 3—Gulf Coast,
13 depending upon which region has the greatest new (and unclaimed) pipeline transport capacity.
14 In this time frame, it is possible that PADD 2 already could be saturated with existing Canadian
15 capacity, and PADD 3 would be the more likely incremental market for greater volumes of crude
16 shale oil. By this point in time, the quality of commercially available shale oil should have
17 stabilized so that the true determining factor would be a market-driven valuation of the crude
18 composition and qualities versus its transportation and processing economics. Either PADD 2
19 or PADD 3 could absorb up to 2 million bbl/day additional shale oil with little refinery
20 configuration restructuring required if the market determines it is economically advantageous
21 to do so.
22

23 In the long term (probably 10+ years), other markets such as PADD 5—West Coast could
24 also become viable. The potential decreases in California and Alaskan North Slope crude
25 production and/or increased insecurity in foreign crude availability could provide the motivation
26 to construct high-capacity pipelines to supply that market.
27

28 Uncertainty as to the exact quality of commercially produced shale oil prevents a precise
29 determination of the feedstock market segment in which it would be most competitive. Current
30 in situ technologies under evaluation show the promise of partial upgrading of crude oil prior to
31 recovery from the oil shale formation as well as the conversion of sulfur and nitrogen-bearing
32 compounds to hydrogen sulfide and ammonia compounds, respectively, either of which can be
33 easily removed from the product stream. Although this hypothesis remains unproven at
34 commercial scales, if it is realized, the resulting crude shale oil could be both lightweight and
35 low in sulfur content (relative to many current conventional feedstocks), which could give it a
36 distinct advantage over both the high-sulfur conventional domestic crude production and the
37 Canadian synthetic crude oil. This may influence both the rate and extent of market penetration
38 for shale oil.
39

40 Refinery expansion and operations will also be influenced by environmental factors,
41 which contribute to the overall market picture. Issues such as air quality (attainment status for
42 each of the primary ambient air quality criteria pollutants as well as source-specific emission
43 limitations) and water availability could constrain or preempt significant expansions of existing
44 refineries or the construction of new refineries in certain geographic areas. It is intuitive that
45 refinery growth occurring in the immediate vicinity of a crude oil source would minimize
46 transportation costs; however, other factors, such as ambient air quality and water availability,

1 could be key constraining factors in refinery expansion that could overwhelm any concerns for
2 transportation costs. In addition to the high water requirement of typical refineries of 1 to 3 bbl
3 of water per barrel of processed crude, the degree of impurities present in crude shale oil could
4 create increased wastewater and waste disposal issues. In the final economic models that are
5 typically employed, transportation costs are nominal and have very little influence over the
6 ultimate decision regarding the location of the refinery relative to the crude oil source. Of a more
7 critical influence is the existing pipeline capacity that links the market areas under consideration.
8 However, as has been suggested in the introduction, pipeline operators will expand their
9 capacities and build pipelines linking new locations once markets are reliably established.

10
11 Environmental controls aimed not at refineries but at some distillate fuel products may
12 also influence the overall market. New low-sulfur fuel requirements will put high-sulfur
13 feedstocks at a disadvantage or will require expensive expanded sulfur control capabilities at
14 refineries currently receiving such feedstocks. The intrinsically lower sulfur content of crude
15 shale oil compared to some conventional crude feedstocks, as well as the ability of crude
16 producers to further reduce sulfur content through in situ retorting techniques and/or mine site
17 upgrading, could greatly increase shale oil's attractiveness to refineries producing such distillate
18 fuels.

21 **9 OTHER POSSIBLE MARKET DRIVERS**

22
23
24 Declines in supply from existing major exporters (e.g., Venezuela and Mexico), domestic
25 sources (North Slope of Alaska), and geopolitical events could create an increasing demand for
26 domestic crude production in the future. Venezuela and Mexico have been primary sources of
27 crude oil, with each providing approximately 1.5 to 1.7 million bbl/day into the United States,
28 but concern for these sources is growing. Venezuela has been unable to return to the level of
29 production in 2001, and the government has become increasingly antagonistic to U.S. interests.
30 Also, there is growing industry concern over the decline of Mexican production because of the
31 lack of investment, which could dramatically impact production levels in the next few years.
32 With two major Western Hemisphere producers facing uncertain futures and continuing concerns
33 over the Middle East and Africa, the medium-term potential for increased demand for domestic
34 crude production could improve the market viability for production and processing of crude
35 shale oil.

36
37 Alaska North Slope production has been in decline and is currently supplying
38 approximately half of its historic peak. Although there are considerable logistical challenges to
39 moving crude to the West Coast, future declines in supply from Alaska could create increased
40 demands on the West Coast that could improve what is currently considered a nonviable market
41 for moving feedstock from the Rocky Mountain region to the West Coast.

42
43 While nearby crude sources are likely declining, world demand for crude oil is expected
44 to increase by 47% by 2030. China and India are expected to account for more than 40% of this
45 increase (EIA 2006f). These forecasts of increasing demand and diminishing resources are
46 creating an international competition, which is being acted on now. China began the process of

1 constructing a Strategic Petroleum Reserve in 2004 and is increasing its relations with oil
2 producers, such as Angola, Central Asia, Indonesia, the Middle East (including Iran), Russia,
3 Sudan, and Venezuela (Office of the Secretary of Defense 2005). Further international energy
4 risk could provide additional incentive for utilization of domestic resources.

5
6 Legislation could also play a role in driving the advancement of shale oil. The Energy
7 Policy Act of 2005 extends the Title VII, National Oil Heat Research Alliance Act of 2000,
8 providing for research for use of distillates as home heating oil. Heating oil equipment is found
9 to “operate at efficiencies among the highest of any space heating energy source.” Further
10 support of this could drive additional demand for the types of distillates that can be produced
11 from upgraded shale oil. The same act also directs the Secretary of Energy to select sites
12 necessary to procure the fully authorized Strategic Petroleum Reserve (SPR) storage volumes.
13 Although additional segregation would be required from the current SPR storage, shale oil could
14 be upgraded to meet additional SPR storage acquisition or even displace existing barrels of
15 conventional oil. The need to extend the physical storage capacity affords an opportunity to
16 evaluate alternative locations, from the existing Gulf Coast-centric storage to support production
17 in the Rocky Mountain region, or storage and consumption in Southern California or the upper
18 Midwest. In addition, Section 369 of the Act directs the Secretary of Defense to procure fuel
19 derived from coal, shale oil, and tar sands. This could also stimulate a demand, especially in the
20 western United States. While the precise nature of future actions implementing these statutory
21 directives is unknown at this time, impacts on the oil shale industry are easily anticipated.

22 23 24 **10 CONCLUSIONS**

25
26
27 The unknowns regarding the quality and availability of crude shale oil, the extent to
28 which it may be upgraded at the site of production, and the time frames for expansions of
29 pipeline capacity for movements outside the immediate production area introduce considerable
30 uncertainty with respect to the timing and specifics of refinery market development. As a result,
31 it is difficult to predict with certainty how the refinery market will respond to oil shale
32 development on public lands over the next 20 years (2007 to 2027). It is likely that during the
33 first 10 years of the study period (2007 to 2017), there will be no commercial oil shale
34 production; activities during this period will be focused on R&D and demonstration only.
35 Commercial-scale production may start around 2017 at some project sites and reach a level of
36 about 1 million bbl/day from those sites within a few years. Additional production from other
37 project sites could start in a similar time frame, and a production rate of approximately
38 2 million bbl/day could be reached around the end of the study period.

39
40 The information presented in this paper defines the factors that will likely impact the
41 incorporation of shale oil into the market. In addition, information from the relatively recent
42 introduction of Canadian synthetic crude can be used to define a possible path for crude shale oil
43 market infusion. To make any projections about the refinery market response to oil shale
44 production, it is necessary to make certain assumptions. It is assumed that the U.S. refinery
45 market will respond in a fashion consistent with past behavior. It is further assumed that both the
46 Canadian crude and other foreign crude will continue at their current levels of availability. This

1 analysis of potential markets for shale oil does not depend upon any reduction in available global
2 supply typically referred to as the peak oil argument. The expected build-out of shale oil
3 production will enter at the beginning of the peak oil argument. Any international decline in
4 crude oil production will only create greater demand for alternative crude production sources. An
5 exception to the assumption that all existing crude supplies remain relatively stable is the
6 Alaskan North Slope crude supply, for which, as noted, current projections forecast a
7 significantly reduced production in the 10-year time frame. In the Alaska projection, the Alaska
8 National Wildlife Refuge is not assumed to be in production.
9

10 Because of the many uncertainties that still exist, it is probable that market development
11 will proceed in different directions during different growth phases of the crude shale oil market.
12 Initially, the market is likely to respond to new crude shale oil production through displacements
13 of similar or complementary quality crude supplies from the refinery stream rather than
14 expansions of refinery capacity. Such displacements, however, will be tempered by conditions in
15 the market, including the relative price of crude oil of similar quality and existing crude oil
16 supply contracts (as in the case of existing contracts for heavy Canadian crude oil).
17

18 On the basis of historic patterns of expansion in refining capacity, refinery expansions to
19 incorporate new crude shale oil supplies will occur incrementally, largely within areas of existing
20 concentrated refining capacity, and only after refiners have identified a long-term profit margin
21 for expanded facilities. The availability of new supplies alone is not sufficient to drive new
22 refining capacity (as seen in the current oversupply of light crude in Wyoming). Only long-term
23 profit potential will provide that incentive.
24

25 The scenario described below reflects the suppositions and constraints discussed in this
26 paper. There is no historic precedent for production increases of this magnitude in such a short
27 period of time; therefore, this scenario may not be accurate. It does not represent the only
28 pathway by which shale oil refining markets will develop but can nevertheless be justified on a
29 number of critical levels.
30

31 Development will likely occur in three phases:

- 32 1. Early adoption and geographically local market penetration within PADD 4,
33
- 34 2. Market expansion outside of PADD 4 with increased logistical capability (for
35 both oil shale production facilities and transportation infrastructure), and
36
- 37 3. High-volume production and multimarket penetration of a mature shale oil
38 industry.
39

40
41 Successful market penetration is a balance of crude shale oil availability, logistical
42 availability (i.e., pipeline transportation), and market demand. Each phase of market maturity for
43 shale oil will confront constraints in one or more of these areas. The relative significance of these
44 constraints will shift during the various phases of maturity.
45

1 Phase 1, early adoption and local market penetration, will likely occur during the first
2 5 years of commercial development. If approximately 1,000,000 bbl/day of oil shale is produced
3 in Colorado during this time, the abundance of shale oil supply will be placed into a refinery
4 market that already is experiencing excess domestic production. Transportation capacity will be
5 the limiting factor during this phase. Until reliable product definition and consistent quality of
6 the crude shale oil are established, refineries will have a slow adoption rate and are more likely
7 to only replace existing sources of crude of comparable quality. While it is unlikely that new
8 refineries will be constructed during this period in response to this new production, the crude
9 transport connections and overall refinery capacities within the PADD 4—Rocky Mountain
10 region will need to be improved in order for these refineries to be early adopters. This could
11 translate into the construction of new pipelines in the PADD 4 region. Demand in PADD 4 is not
12 expected to increase dramatically during this time, but refineries could potentially reconfigure
13 their processes or create new blends of crude stocks to better align their feeds with desired
14 products. The potential qualities of crude shale oil could be similar to domestic light crudes and
15 if market conditions allow, could compete with an already oversupplied local domestic crude
16 market in the immediate vicinity. Alternatively, Phase 1 could be very short-lived, or skipped
17 entirely, and Phase 2 conditions could prevail.
18

19 Phase 2, market expansion beyond PADD 4, is likely to involve expansion of the
20 transportation network, allowing distribution of crude shale oil outside of PADD 4. At the point
21 in time that PADD 4 reaches a saturation point, thus presenting a growth-limiting factor, Phase 2
22 expansions beyond PADD 4 will need to occur. This could occur starting around 2022 (or
23 sooner) and extend until 2027 or beyond. To accomplish this, expansion of pipeline capacities to
24 multiple markets outside of PADD 4 will be required. As addressed above, the most likely
25 markets are the Midwest and Gulf Coast, although some potential growth could occur in the local
26 markets. Because of the limited forecasted refinery expansion over this time period, new market
27 penetration will require displacement of alternative sources of crude oil. The overall cost of
28 production, the final qualities of the crude shale oil, and the availability of out-of-region
29 transport will determine the economics and, subsequently, its economic viability. During this
30 period, it is also unlikely that new refineries, will be constructed in any of the PADDs; more
31 likely, the transportation network will expand and there could be some expansions at existing
32 refineries.
33

34 Phase 3 represents multimarket penetration and the maturation of the shale oil industry
35 where the market is at equilibrium and crude shale oil availability is the limiting factor rather
36 than transportation or refinery capacity. This phase assumes large volumes of crude shale oil
37 would be produced (approximately 2 million bbl/day). By this time, it is realistic to expect that
38 PADD 5—West Coast refineries that have been utilizing California and Alaskan North Slope
39 crude will be searching for alternative sources of supply, which may bring these refineries into
40 the shale oil market equation. The market viability of these levels of production is probably
41 dependent upon integration with multiple regional markets and assumes ongoing economic
42 viability versus alternative sources. Even in this long-range projection, neither demand or
43 refining capacity in the PADD 4 local markets is expected to increase to a level that could utilize
44 the expected shale oil production; thus, development of markets in other regions will be
45 necessary to sustain the industry or allow it to reach its full projected production capacity.
46

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

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