APPENDIX B:

TAR SANDS DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW

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TAR SANDS DEVELOPMENT BACKGROUND AND TECHNOLOGY OVERVIEW

This appendix describes the geology of the tar sands resource area, the resource, and the history of tar sands development in the western United States, and it provides an overview of the technologies that have been applied to tar sands development. It introduces technologies that may be employed in future developments on U.S. Department of the Interior, Bureau of Land Management (BLM)-administered lands. The technologies that are addressed include those used for recovery (i.e., mining), processing (i.e., separation and pyrolysis of the hydrocarbon fraction), and upgrading of tar sands resources. Finally, Attachment B1 provides an analysis of how the refining industry may adjust to the availability of syncrude feedstocks derived from U.S. tar sands.

Tar sands deposits occur throughout the world except in Australia and Antarctica (Han and Chang 1994). The largest deposits occur in Alberta, Canada (the Athabasca, Wabasha, Cold Lake, and Peace River areas), and in Venezuela. Smaller deposits occur in the United States, with the larger individual deposits in Utah, California, New Mexico, and Kentucky.

Accurate estimates of the reserves of hydrocarbon liquids in tar sands deposits have not been made, but worldwide demonstrated deposits (excluding inferred deposits) may total about 320×10^9 m^3 ($2{,}000 \times 10^9$ bbl), with the largest share in Alberta, Canada, at about 270×10^9 m^3 ($1{,}700 \times 10^9$ bbl). There are about 546 occurrences of tar sands in 22 states in the United States in deposits that may have more than 4.5×10^9 m^3 (28×10^9 bbl) of hydrocarbons. About 60% of this potential resource is located in Utah (Spencer et al. 1969; Meyer 1995).

The term tar sands, also known as oil sands (in Canada), or bituminous sands, commonly describes sandstones or friable sand (quartz) impregnated with a viscous, extra-heavy crude oil known as bitumen (a hydrocarbon soluble in carbon disulfide). Significant amounts of fine material, usually largely or completely clay, are also present. The degree of porosity varies from deposit to deposit and is an important characteristic in terms of recovery processes. The bitumen makes up the desirable fraction of the tar sands from which liquid fuels can be derived. However, the bitumen is usually not recoverable by conventional petroleum production techniques (Oblad et al. 1987; Meyer 1995; Speight 1997).

The properties and composition of the tar sands and the bitumen significantly influence the selection of recovery and treatment processes and vary among deposits. In the so-called “wet sands” or “water-wet sands” of the Athabasca deposit, a layer of water surrounds the sand grain, and the bitumen partially fills the voids between the wet grains. Utah tar sands lack the water layer; the bitumen is directly in contact with the sand grains without any intervening water (Speight 1997); such tar sands are sometimes referred to as “oil-wet sands.” Typically, more than 99% of mineral matter is composed of quartz and clays. The general composition of typical deposits at the P.R. Spring Special Tar Sand Area (STSA) showed a porosity of 8.4 vol% with the solid/liquid fraction being 90.5% sand, 1.5% fines, 7.5% bitumen, and 0.5% water by weight

(Grosse and McGowan 1984). Utah deposits range from largely consolidated sands with low porosity and permeability to, in some cases, unconsolidated sands (Speight 1997). High concentrations of heteroatoms tend to increase viscosity, increase the bonding of bitumen with minerals, reduce yields, and make processing more difficult (Oblad et al. 1987).

To utilize a tar sands resource in a mining operation, the bitumen must be recovered from its natural setting, extracted from the inorganic matrix (largely sand and silt) in which it occurs, and upgraded to produce a synthetic crude oil suitable as a feedstock for a conventional refinery. In general, it takes about 2.0 tonnes (2.2 tons) of surface-mined Athabasca tar sands to produce 159 L or 1 barrel (42 gal) of synthetic oil (Oil Sands Discovery Center 2006a). Nonmining operations recover the bitumen already free of the matrix (sand and clays) in which it originally occurred. Preparation may require removal of bitumen or vaporized bitumen from steam, other gases, water, or solvents. Depending on the end product required, upgrading may not be required.

At this time, there are no commercial tar sands operations for the production of oil for energy use on public lands in Utah. Commercial development could occur on lands with existing combined hydrocarbon leases (CHLs). The BLM does predict some commercial development on public lands under the new tar sands leasing program that would be established with this *Allocation of Oil Shale and Tar Sands Resources on Lands Administered by the Bureau of Land Management in Colorado, Utah, and Wyoming Draft Programmatic Environmental Impact Statement (PEIS) and Possible Land Use Plan Amendments* and the accompanying Record of Decision (ROD). It is also likely that additional development would proceed on private and/or state lands. The impacts being evaluated in the PEIS could occur under either a CHL or under a tar sands lease; however, the decisions that may result from this PEIS and its accompanying ROD are not applicable to CHLs.

The following discussion includes general information on the geology, development history, and technologies for tar sands development that are being considered in this PEIS. Chapter 9 of the PEIS provides a glossary of technical terms used in the PEIS and its appendices, including geologic terms.

B.1 DESCRIPTION OF GEOLOGY

Tar sands are sedimentary rocks containing bitumen, a heavy hydrocarbon compound. Tar sands deposits may be divided into two major types. The first type is a breached petroleum reservoir where erosion has removed the capping layers from a reservoir of relatively heavy petroleum, allowing the more volatile petroleum hydrocarbons to escape. The second type of tar sands deposit forms when liquid petroleum seeps into a near-surface reservoir from which the more volatile petroleum hydrocarbons escape. In either type of deposit, the lighter, more volatile hydrocarbons have escaped to the environment, leaving the heavier, less volatile hydrocarbons in place. The material left in place is altered by contact with air, bacteria, and groundwater. Because of the very viscous nature of the bitumen in tar sands, tar sands cannot be processed by normal petroleum production techniques.

Tar sands deposits are not uniform. Differences in the permeability and porosity of the reservoir rock and varying degrees of alteration by contact with air, bacteria, and groundwater mean that there is a large degree of uncertainty in the estimates of the bitumen content of a given tar sands deposit. Estimates may be off by an order of magnitude (a factor of 10) (USGS 1980a–k).

More than 50 tar sands deposits occur in Utah. Limited data are available on many of these deposits, and the sizes of the deposits are based on estimates. Most of the known bitumen occurs in just a few deposits. The deposits that are being evaluated in this PEIS are those deposits classified in the 11 sets of geologic reports (minutes) prepared by the U.S. Geological Survey (USGS) in 1980 (USGS 1980a–k) and formalized by Congress in the Combined Hydrocarbon Leasing Act of 1981 (Public Law [P.L]. 97-78).[1] While there are 11 sets of minutes, in some cases, the geologic report refers to more than one deposit. For example, the minutes titled *Asphalt Ridge–Whiterocks and Vicinity* discuss the Asphalt Ridge deposit, the Whiterocks deposit, the Asphalt Ridge Northwest deposit, the Littlewater Hills deposit, and the Spring Hollow deposit. All of these deposits are included in the designated STSA and in this analysis for the PEIS. For the sake of convenience, the deposits are often combined and referred to on maps, and otherwise, as the Asphalt Ridge STSA.

Tar sands deposits outside the areas designated by the Secretary of the Interior in the 11 sets of minutes are not available for leasing under the tar sands program, but would be available for development under a conventional oil and gas lease. Figure B-1 shows the locations of the STSAs in Utah, as defined by the 11 sets of minutes from the USGS. Figure B-2 shows the generalized stratigraphy of the areas in Utah where the STSAs are present.

Table B-1 provides estimates of the heavy oil resources for the 11 STSAs as published by Ritzma (1979). Additional resource estimates have been published in an Interstate Oil Compact Commission report titled, *Major Tar Sand and Heavy Oil Deposits of the United States* (Lewin and Associates 1983). The data indicate that a large percentage of the tar sands bitumen in Utah is located within just a few of the STSAs. The following sections summarize the information that is available for each of the STSAs. The level of detail varies between the STSAs because significant amounts of information have been compiled only for those STSAs with the largest resource base.

B.1.1 Argyle Canyon–Willow Creek STSA

The Argyle Canyon–Willow Creek STSA, hereafter referred to as the Argyle Canyon STSA, is located in the southwestern portion of the Uinta Basin and includes deposits in two areas. These deposits are sometimes referred to independently as the Argyle Canyon deposits, which are located in the Bad Land Cliffs area, and the Willow Creek deposits, which are located along the western end of the Roan Cliffs. For the purposes of this PEIS, the Argyle Canyon

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1 The boundaries of the designated STSAs were determined by the Secretary of the Interior's orders of November 20, 1980 (Volume 45, pages 76800–76801 of the *Federal Register* [45 FR 76800–76801]) and January 21, 1981 (46 FR 6077–6078).

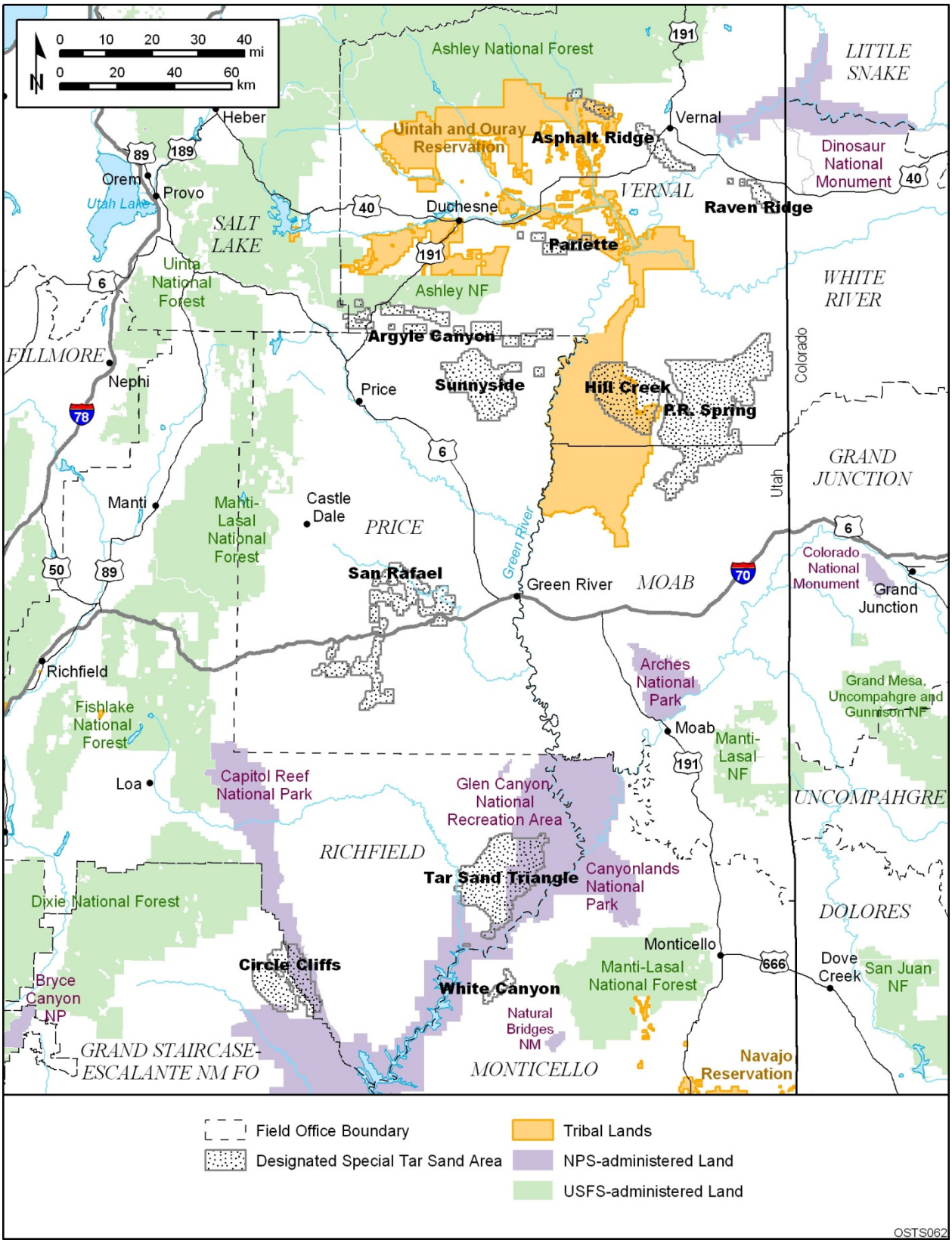

FIGURE B-1 Special Tar Sand Areas in Utah

STSA includes both areas. All information presented in this section is from Blackett (1996) unless otherwise noted.

The Argyle Canyon portion of the STSA is highly dissected by a north-south trellis-type drainage. The rocks present in this deposit are the Parachute Creek Member and the Deltaic facies of the Eocene Green River Formation, which is overlain by the Eocene Uinta Formation. The Parachute Creek Member is regularly bedded and contains siltstone, mudstone, and oil shale. The Deltaic facies is irregularly bedded, lenticular micaceous sandstone and interbedded mudstone.

The Willow Creek portion of the area is characterized by high plateaus dissected by deep, steep-walled canyons. Rocks present in the Willow Creek deposit are the upper part of the Garden Gulch Member and the lower part of the Parachute Creek Member of the Green River Formation (Eocene). The Garden Gulch Member consists of interbedded thin sandstone, siltstone, shale, and limestone. The Parachute Creek Member is composed of massive beds, thinning upward, of fine-grained sandstone, interbedded with siltstone and shale.

Within the Argyle Canyon deposit, most of the bitumen is contained in the sandstones of the Deltaic facies. Within the Willow Creek deposit, channel sandstones contain most of the bitumen. Recovery of the bitumen in areas near outcrops, with gentle dips, would be amenable to surface mining. The remainder of the area would have to be developed by in situ methods (BLM 1984).

B.1.2 Asphalt Ridge–Whiterocks and Vicinity STSA

The Asphalt Ridge–Whiterocks and Vicinity STSA, hereafter referred to as the Asphalt Ridge STSA, is located along Asphalt Ridge, on the north-northeast flank of the Uinta Basin. Asphalt Ridge is a northwest-southeast trending cuesta, with dips to the southwest. All information presented in this section is from Blackett (1996) unless otherwise noted.

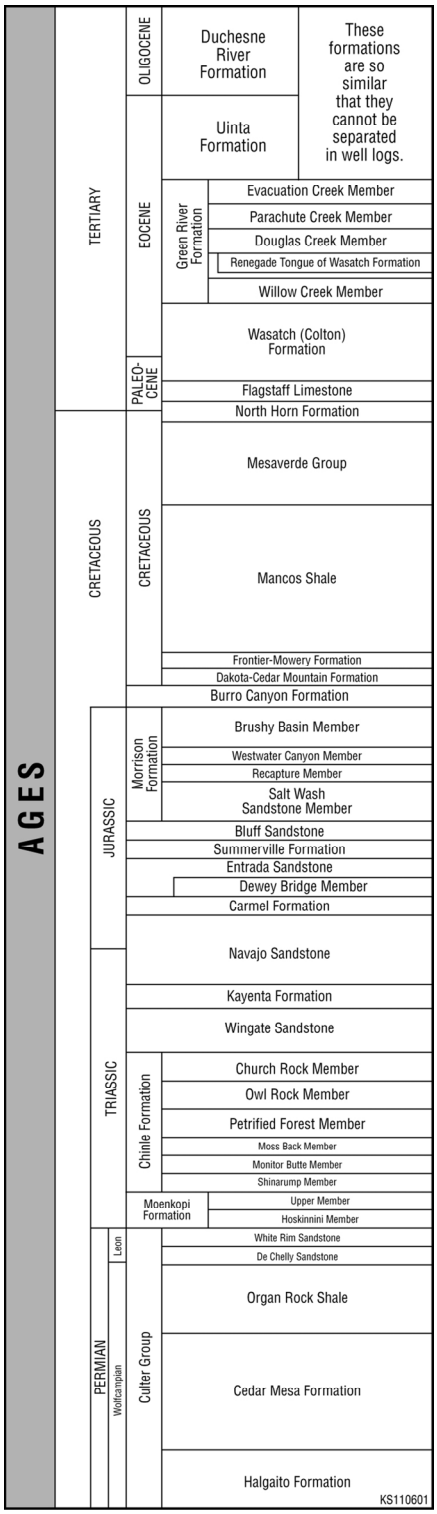

FIGURE B-2 Generalized Stratigraphy of the Areas in Utah Where the STSAs Are Present

TABLE B-1 Estimated Resources in Place in Utah Tar Sands Deposits

	Measured (million bbl)[a]	Speculative (million bbl)
Major Deposits		
Uintah Basin		
P.R. Spring	2,140	2,230
Hill Creek	320	560
Sunnyside	4,400	1,700
Whiterocks	60	60
Asphalt Ridge	830	310
Paradox Basin		
Tar Sand Triangle	2,500	420
Nequoia Arch	730	160
Circle Cliffs Uplift		
Circle Cliffs	590	1,140
San Rafael Uplift		
San Rafael Swell	300	250
Subtotal	11,870	6,830
Minor Deposits		
Uinta Basin		
Argyle Canyon	–[b]	50–75
Raven Ridge	–	75–100
Rimrock	–	25–30
Cottonwood–Jacks Canyon	–	20–25
Littlewater Hills	–	10–12
Minnie Maud Creek	–	10–15
Pariette	–	12–15
Willow Creek	–	10–15
San Rafael Uplift		
Black Dragon	–	100–125
Chute Canyon	–	50–60
Cottonwood Draw	–	75–80
Red Canyon	–	60–80
Wickiup	–	60–75
Subtotal		557–707
Total	11,870	7,387–7,537

[a] bbl = barrel; 1 bbl syncrude = 42 gal.

[b] A dash indicates no formal quantification available.

Source: Ritzma (1979).

The rock units present at Asphalt Ridge, in order of decreasing age, are the Mesaverde Group (Asphalt Ridge Sandstone, Mancos Shale, and Rim Rock Sandstone; all Cretaceous), possibly the Uinta Formation (Eocene), and the Duchesne River Formation (Eocene-Oligocene). The Uinta Formation may or may not be present as the contact between the Mesaverde Group and the Duchesne River Formation; it is gradational and difficult to recognize. The Duchesne River Formation unconformably overlies the Rim Rock Sandstone. Both the Duchesne River Formation and the Rim Rock Sandstone dip to the south-southwest at gradients ranging from 8° to 30°; the Rim Rock Sandstone generally has the steeper dips.

The White Rocks tar sands deposit is found in the Navajo sandstone, which dips from 70° to near vertical due to a major regional uplift and folding. Severe faulting has caused a large offset of the Navajo and other formations in the subsurface. However, within the limits of the deposit as seen at the surface, local faulting is small. The over- and underlying strata are impervious shales of the adjacent Chinle and Carmel Formations, which have sealed the bitumen in the Navajo.

Several faults are known to have cut across the trend of the ridge. One has 150 ft of vertical displacement. At least one fault acted as a barrier to hydrocarbon migration, as the Asphalt Ridge Sandstone is bitumen saturated to the northwest of the fault and unsaturated to the southeast.

The Rim Rock Sandstone, the Uinta Formation (where present), and the Duchesne River Formation all contain bitumen in the Asphalt Ridge area. The Rim Rock Sandstone is generally bitumen saturated for its entire outcrop length in the Asphalt Ridge area. The Uinta Formation generally contains bitumen only in sandy beds near the southern part of Asphalt Ridge. The bitumen saturation of the Duchesne River Formation varies both laterally and vertically. Rock composition of the Duchesne River Formation ranges from shale to conglomerate. The rocks with the greatest porosity, coarse sandstones, tend to have the highest bitumen saturations.

It has been suggested that the bitumen in the White Rocks deposit is Tertiary and has migrated across joints and unconformities to the Jurassic Navajo. However, original paths of migration are not clear and Paleozoic source rocks have been suggested as an alternate hypothesis for the source of hydrocarbons. In the subsurface, the bitumen extends down to the water/oil contact in the steeply dipping Navajo sandstone.

Recovery of the bitumen at this STSA would be amenable to surface mining along the outcrop on Asphalt Ridge. However, the surface minable portion of the deposit is primarily on state and private lands. In the remainder of the area, the deposits would have to be recovered by in situ methods (BLM 1984).

B.1.3 Circle Cliffs East and West Flanks STSA

The Circle Cliffs East and West Flanks STSA, hereafter referred to as the Circle Cliffs STSA, is located in south-central Utah, along the Circle Cliffs anticline. All information presented in this section is from BLM (1984) unless otherwise noted.

Rocks exposed at the surface in the vicinity of the Circle Cliffs anticline, in decreasing age order, are the Kaibab Limestone (Permian), Moenkopi Formation (Torrey Member and Moody Creek Member; Triassic), Chinle Formation (including the Shinarump Conglomerate; Triassic), Wingate Sandstone (Triassic/Jurassic), Kayenta Formation (Jurassic), Navajo Sandstone (Jurassic), Carmel Formation (Jurassic), Entrada Sandstone (Jurassic), and several younger units (Short 2006). The beds on the eastern side of the anticline dip from a few degrees to more than 25°. The beds on the western side of the anticline dip from 2° to 3° to the west.

The bitumen is contained in shoreface and fluvial-deltaic sandstones of the Torrey and Moody Creek Members of the Moenkopi Formation (Schamel and Baza 2003). Recovery of the bitumen would only be amenable to surface mining in very limited areas. In most of the area, the deposits would have to be recovered by in situ methods (BLM 1984; Kohler 2006).

B.1.4 Hill Creek STSA

The Hill Creek STSA is located along the Book Cliffs, on the south flank of the Uinta Basin. It lies to the west of the P.R. Spring STSA and east of the Sunnyside and Vicinity STSA. All information presented in this section is from Blackett (1996) unless otherwise noted.

The Hill Creek STSA tar sands deposits are contained entirely within the Eocene Green River Formation. The composition of the Green River Formation includes oil shale, marlstone, shale, siltstone, sandstone, limestone, and tuff. The three mappable units of the Green River Formation in the vicinity of the Hill Creek deposit, in order of decreasing age, are the Douglas Creek Member, the Parachute Creek Member, and the Evacuation Creek Member. The Mahogany Bed, an important oil shale resource, lies between the Douglas Creek and Parachute Creek Members.

There are five bitumen-impregnated zones in the Hill Creek STSA. Four of these zones are in the upper portions of the Douglas Creek Member, and one is in the lower part of the Parachute Creek Member. In ascending order, these zones have been designated A, B, C, D, and E. The zones can be correlated throughout the deposit.

The extent of bitumen saturation varies laterally and vertically throughout each of the zones. Overburden thicknesses are too great throughout most of the deposit for surface mining to be feasible, and it is likely that recovery of the bitumen would require in situ methods (BLM 1984).

B.1.5 Pariette STSA

The Pariette STSA is located on the southern flank of the Uinta Basin in an area of low relief near the topographic center of the basin. All information presented in this section is from Blackett (1996) unless otherwise noted.

Rocks of the Uinta Formation (Eocene) are present within the Pariette STSA. The Uinta Formation rocks in the STSA are overlain by Quaternary surficial deposits. The Uinta Formation is nearly flat in the STSA, dipping 1° to 4° to the north.

The bitumen-saturated zones are typically lenticular, fluvial sandstones. There is a large amount of horizontal and vertical variability in bitumen saturation levels within the Pariette STSA deposits. The small size and discontinuous nature of the individual areas of rock saturated with bitumen would tend to limit in situ production to a few of the larger bitumen-saturated areas. Development is limited by the small size, the lean quality (saturation is low), and the discontinuous lenticular-occurring nature of the deposits (USGS 1980e).

B.1.6 P.R. Spring STSA

The P.R. Spring STSA is located along the Book Cliffs in the southeastern part of the Uinta Basin, to the east of the Hill Creek STSA. The topography in the area is relatively flat, with narrow plateaus and mesas incised by intermittent and perennial streams. All information presented in this section is from Blackett (1996) unless otherwise noted.

The geology of the Hill Creek STSA and the P.R. Spring STSA is essentially identical. The P.R. Spring STSA tar sands are contained entirely within the Eocene Green River Formation. The composition of the Green River Formation includes oil shale, marlstone, shale, siltstone, sandstone, limestone, and tuff. The three mappable units of the Green River Formation in the vicinity of the P.R. Spring deposit, in order of decreasing age, are the Douglas Creek Member, the Parachute Creek Member, and the Evacuation Creek Member. The Mahogany Bed, an important oil shale resource, lies between the Douglas Creek and the Parachute Creek Members.

There are five bitumen-impregnated zones in the P.R. Spring STSA. Four of these zones are in the upper portions of the Douglas Creek Member, and one is in the lower part of the Parachute Creek Member. In ascending order, these zones have been designated A, B, C, D, and E. The zones can be correlated throughout the deposit.

The extent of bitumen saturation varies laterally and vertically throughout each of the zones. Numerous tar seeps occur along the outcrop of the bitumen-impregnated areas within the STSA. They tend to be active during periods of wet weather and inactive during drier periods.

Overburden thicknesses are too great throughout most of the deposit for surface mining to be feasible, except in the southern part of the STSA. It is likely that recovery of the bitumen would require in situ methods, except in the southern part of the STSA where these deposits are considered among the most valuable for surface mining (USGS 1980f).

B.1.7 Raven Ridge–Rim Rock and Vicinity STSA

The Raven Ridge–Rim Rock and Vicinity STSA, hereafter referred to as the Raven Ridge STSA, is located on the north flank of the Uinta Basin and includes deposits in two areas. These deposits are sometimes referred to independently as the Raven Ridge deposits, which are located along a series of northwest-trending hogbacks known as Raven Ridge, and the Rim Rock deposits, which lie at the east end of a series of low, west-northwest-trending hogbacks called the Rim Rock. The Raven Ridge portion of the STSA is east of Asphalt Ridge. The Rim Rock portion lies between Raven Ridge and Asphalt Ridge. All information presented in this section is from Blackett (1996) unless otherwise noted.

Rocks present within the Raven Ridge deposit include, in order of decreasing age, the Paleocene/Eocene Green River Formation (Douglas Creek Member, Parachute Creek Member, and Evacuation Creek Member) and the Eocene Uinta Formation. The Mahogany oil shale zone occurs above the Raven Ridge tar sands deposit. Rocks in the Raven Ridge area dip from 10° to 85° southwest, with an average dip of 30°. They are composed of shoreline and deltaic facies sandstone, limestone, and shale in the Green River Formation, and fluvial-deltaic shale, sandstone, and pebble conglomerate in the Uinta Formation. All four of the rock units present in the Raven Ridge area contain some bitumen. Saturation levels vary greatly between units, as well as in lateral and vertical extent.

The Wasatch Formation (Paleocene) and the Douglas Creek and Parachute Creek Members of the Green River Formation are present in the Rim Rock part of the STSA. Rocks in the Rim Rock area dip as much as 76° to the southwest. Each successively younger unit overlaps and truncates the next older unit. Bitumen is located within the Wasatch Formation sandstones and in Green River sandstones that truncate older Wasatch Formation rocks.

Recovery of the bitumen by surface mining would be possible in the Raven Ridge STSA only along the outcrops on Raven Ridge. In situ methods would be needed elsewhere (BLM 1984).

B.1.8 San Rafael Swell STSA

The San Rafael Swell STSA is located in the southwestern portion of Utah. The San Rafael Swell is a breached dome, with the core of older rocks exposed in the middle of the dome. The rocks dip away from the geographic center of the dome, in all directions. Schamel and Baza (2003) report that the White Rim Sandstone, within the San Rafael Swell deposit, contains bitumen. The White Rim Sandstone is present only on the eastern most edge of the San Rafael Swell. All information presented in this section is from BLM (1984) unless otherwise noted.

Rocks exposed at the surface in the vicinity of the San Rafael Swell, in order of decreasing age, are the Cutler Group (White Rim Sandstone; Permian), Kaibab Limestone (Permian), Moenkopi Formation (Sinbad Limestone Member and Black Dragon Member; Triassic), Chinle Formation (Triassic), Wingate Sandstone (Triassic/Jurassic), Kayenta

Formation (Jurassic), Navajo Sandstone (Jurassic), and San Rafael Group (Carmel Formation, Entrada Sandstone, Curtis Formation, and Summerville Formation; Jurassic) (USGS 2006).

All of the rock units in the San Rafael Swell area contain bitumen in some areas (Schamel and Baza 2003). Within the deposit, most of the bitumen occurs within the lower and middle portions of the Black Dragon Member of the Moenkopi Formation. The other units contain lesser amounts of bitumen, with some such as the Sinbad Limestone containing only isolated spots of bitumen.

In situ methods would be the preferred methods of production for the San Rafael Swell STSA. The overburden is too great for recovery of the bitumen by surface mining (BLM 1984).

B.1.9 Sunnyside and Vicinity STSA

The Sunnyside and Vicinity STSA, hereafter referred to as the Sunnyside STSA, is located along the Roan Cliffs on the southwestern flank of the Uinta Basin. The topography of this area is characterized by high relief and rugged terrain. All information presented in this section is from Blackett (1996) unless otherwise noted.

The rock units present at Sunnyside, in order of decreasing age, are Colton Formation (Paleocene/Eocene) and the Lower Green River Formation (Eocene). Colton Formation rocks are shale, siltstone, and sandstone, which were deposited in a fluvial-deltaic environment. The Green River rocks were deposited in a lacustrine environment and are composed of shale, marlstone, siltstone, sandstone, limestone, and tuff. Bitumen in the deposit is typically contained in sandstone. The bitumen content is typically inversely proportional to the distance from the deltaic complex.

The rocks in the Sunnyside area dip to the northeast at 3° to 12°. Small-scale faulting and fracturing occur in the area but do not appear to have affected bitumen emplacement.

The depositional environments in this area have resulted in a complex stratigraphy. Bitumen saturation may vary greatly within just a few feet, with bitumen-saturated rock and barren rock occurring within a few feet of each other. Surface mapping has identified as many as 32 bitumen saturated beds.

Recovery of the bitumen by both surface mining and in situ methods would be needed to fully develop the Sunnyside deposit (BLM 1984).

B.1.10 Tar Sand Triangle STSA

The Tar Sand Triangle STSA is located in southeastern Utah along the western edge of the Monument Upwarp. The topography of the area is a dissected plateau. The margins of the plateau have stair-step topography, and mesas and buttes occur as outliers from the plateau

(BLM 1984). All information presented in this section is from Glassett and Glassett (1976) unless otherwise noted.

The rocks present in the Tar Sand Triangle STSA, in order of decreasing age, include the Cutler Group (Cedar Mesa Sandstone and White Rim Sandstone; Permian), Moenkopi Formation (Triassic), and Chinle Formation (Shinarump Conglomerate; Triassic). The Monument Upwarp is a westward-dipping monocline, and the Permian and Triassic rocks of central Utah pinch out against the upwarp. The bitumen in the Tar Sand Triangle STSA appears to be the residue of a gigantic oil field located in the stratigraphic trap formed by this pinch out. The oil field was breached by erosion allowing the more volatile components to escape, leaving the less volatile components behind.

Although bitumen is found in the Cedar Mesa Sandstone, White Rim Sandstone, Moenkopi Formation, and Shinarump Conglomerate, most of the bitumen is located in shoreface and eolian deposits of the Permian White Rim Sandstone near its southeastern extent, as it pinches out against the Monument Upwarp (Schamel and Baza 2003).

The Tar Sand Triangle deposit may be technically suitable for surface mining; however, the remoteness of the area and other considerations could limit this potential (BLM 1984).

B.1.11 White Canyon STSA

The White Canyon STSA is located south of the Tar Sand Triangle STSA, in the White Canyon area of southeastern Utah. The topography in the area is that of one large mesa with bench and slope topography along its margins. The ground below the mesa is incised by White Canyon. All information presented in this section is from BLM (1984) unless otherwise noted.

Rocks present in the White Canyon area, in order of decreasing age, include DeChelly and/or White Rim Sandstones (these two sandstones are coeval; Permian), Moenkopi Formation (Hoskinnini Member; Triassic), and Chinle Formation (Shinarup Member; Triassic) (Beer 2005). Other rock units may be present but are not relevant to the tar sands. The Hoskinnini Member, which hosts all of the bitumen in the White Canyon STSA, pinches out toward the northwestern part of the STSA.

The lack of site-specific data precludes any consideration of mining methods for the White Canyon deposit. The data available on the quality of the deposit suggest that it is not of commercial grade. It may be too heavily jointed for in situ methods, and heavy overburden appears to be unfavorable for surface mining (USGS 1980k).

B.2 PAST EXPLORATION AND DEVELOPMENT ACTIVITY

The mining of petroleum-bearing materials from tar sands has been practiced for thousands of years. Petroleum and bitumen were mined in the Sinai Peninsula before 5,000 B.C.

The bitumen was used as an adhesive, brick binder, and waterproofing agent and, somewhat later, it was used to produce petroleum as a fuel. However, the distillation process was lost and not used again until the middle of the nineteenth century with the advent of drilling for oil. Underground oil mining was practiced in the Alsace region of France from about 1735 to 1866. The mined sand was treated on the surface with boiling water to release the oil. After 1866, oil was obtained by letting it drain into mine shafts where it was recovered as a liquid (National Academy of Sciences 1980; Meyer 1995; Speight 1995).

Natural bitumen (or natural asphalt) has been used throughout the world, primarily in the last 200 years, during which time it was widely used as a paving material. This use has largely been replaced by the use of manufactured asphalt. In the 1890s, the Canadian government became interested in oil sands deposits. Research on recovery mining from the Athabasca oil sands began in the 1920s. Three extensive pilot-scale operations were conducted between 1957 and 1967, and commercial operations began in 1967 when the Great Canadian Oil Sands Company (now Suncor) started open-pit mining using bucket-wheel excavators, conveyor belts, and hot water extraction (Oblad et al. 1987; Meyer 1995; Speight 1995, 1997; Woynillowicz et al. 2005). By 1976, cyclic steam recovery had been piloted by Imperial Oil Limited at Cold Lake. Syncrude Canada Ltd. opened the Athabasca deposits in 1978 using draglines, bucket-wheel reclaimers, and conveyor belts. By 1986, steam-assisted gravity drainage (SAGD) had been piloted, and in situ combustion was being researched in Canada. Suncor and Syncrude were in commercial operation as was Imperial Oil's cyclic steam facility. By 1996, both Suncor and Syncrude had converted their extractions to truck and shovel operations. For surface mining, hydrotransport (the transport of mined sand as a slurry of warm water and sand in pipes) rather than conveyor belts was used to transport mined sand to the extraction plant for cold-water extraction, mechanical separation, and by-product recovery. Several new in situ projects were also in commercial operation (Oil Sands Discovery Center 2006a.) By 2004, about two-thirds of the recovered oil sands in Alberta were mined; about one-third was recovered by in situ operations (Alberta Economic Development 2006).

In Utah, the amount of exploration and development for tar sands resources has varied from location to location. No known exploration or development activities have occurred at the Argyle Canyon, Circle Cliffs, Hill Creek, Pariette, San Rafael Swell, Tar Sand Triangle, or White Canyon STSAs. A brief description of previous activities at the other STSAs is provided below (from Blackett 1996).

- *Asphalt Ridge STSA.* The Asphalt Ridge deposit has been the target of many exploration and development efforts. It was mined at least as early as the 1920s when the town of Vernal, Utah, paved its streets with material from the deposit. Between 1910 and 1950, a number of shallow wells were drilled in the area in an attempt to locate liquid hydrocarbons below the bitumen cap. During the 1930s, a hot-water extraction plant was built to extract tar from the deposit. Knickerbocker Investment Company and W.M. Barnes Engineering Company conducted a comprehensive evaluation program on Asphalt Ridge in the early 1950s. Sohio Petroleum Company then leased Asphalt Ridge and conducted its own evaluation program. In 1970 or 1971, Major Oil Company obtained a working agreement with Sohio to strip-mine the tar sands and build

and operate an extraction plant. Hot water was used to strip the bitumen from the crushed run-of-mine material, and the bitumen was shipped to a refinery in Roosevelt, Utah. Arizona Fuels Corporation and Fairbrim Company acquired the operation in 1972. In the 1970s, Sun Oil Company, Texaco, Phillips Petroleum Company, and Shell Oil Company conducted exploratory drilling at Asphalt Ridge. The U.S. Department of Energy (DOE) conducted extensive field experiments on the deposit between 1971 and 1982.

- *P.R. Spring STSA.* In 1900, John Pope drilled an oil test well in the P.R. Spring deposit. During the early twentieth century (the exact date is unknown), a 50-ft-long adit was driven into a tar sands outcrop in the P.R. Spring area. A steel pipe was run from the adit to a metal trough to collect the gravity-drained oil. In the 1970s and 1980s, the P.R. Spring deposit was the target of intense exploration and research activity by several companies and government agencies. The U-tar Division, Bighorn Oil Company, operated a 100-bbl/day pilot plant in the area. Although several other companies proposed development operations for the P.R. Spring deposit, no viable commercial production has occurred.

- *Raven Ridge STSA.* Sporadic attempts to develop the Raven Ridge deposit were made before 1964. Western Tar Sands, Inc., conducted test mining activities on the deposit during the summer of 1980 and planned to build a 100-bbl/day production facility. This plant was not built, and there have been no other exploration or development activities at the STSA since.

- *Sunnyside STSA.* The Sunnyside deposit was mined, primarily for road construction, from 1892 to the late 1940s. The mined material was transported over a 3-mi-long aerial tram and then trucked to the railhead at Sunnyside, where it was shipped to five other western states. A large number of companies, including Shell Oil Company, Signal Oil and Gas Company, Texaco, Gulf Oil Corporation, Pan-American Petroleum Corporation, Phillips Petroleum, Sabine Resources, Cities Service, Amoco, Chevron Resource Company, Great National Corporation, and Mono Power Company, conducted activities in the Sunnyside deposit from 1963 through 1985. Shell Oil Company, Signal Oil and Gas Company, Pan-American Petroleum Corporation, Mono Power Company, and Great National Corporation all conducted pilot operations on the deposit. Sunnyside sandstone was mined as a road-paving material as early as 1892 through 1948. These deposits were also the site of Shell Oil's steam flood pilot plant from 1964 to 1967 and a mining and bitumen extraction operation from 1982 to 1985.

B.3 PRESENT EXPLORATION AND DEVELOPMENT ACTIVITY

Currently, little tar sands development activity is underway on public lands in Utah. As of 2006, according to the Utah Office of Energy Policy (Wright 2006), the only ongoing tar sands

operations in Utah were small pilot-scale and exploration operations and a few small mining operations by counties to recover road materials (including operations by Uintah County to excavate materials at Asphalt Ridge for road surfacing). The Utah Division of Oil, Gas and Mining expected to see several of the pilot operations expand to large mines ranging from 5 to possibly 80 acres in size. Specifically, the Division projected three large mines (two on private and one on state lands) and eight small mines (one on private and seven on state lands) in the future. As of summer 2012, progress on the development of tar sands for oil production remained at the research and development level, with no commercial oil production from tar sands in operation. The University of Utah prepared an assessment of the technical, economic, and legal aspects of North American heavy oil, oil sands, and oil shale resources in response to the Energy Policy Act of 2005 (University of Utah 2007). This report notes that no significant tar sands development has taken place on BLM leases granted in 1995 on about 14,000 acres in the Sunnyside and P.R. Spring deposits.

For several years, Nevtah Capital Management Corp. and its joint venture partner, Black Sands Energy (formerly known as Cassandra Energy, Inc.), have been working to develop an oil extraction technology for commercial tar sands development. Initial tests were conducted at the Asphalt Ridge STSA. On August 1, 2006, the companies announced the completion of construction of their first commercial production unit, which was built off-site and has a production capacity of 400 to 500 bbl/day of syncrude. The companies hold a total of 13 leases covering 11,000 acres within the Asphalt Ridge, Sunnyside, and P.R. Spring STSAs (Nevtah Capital Management Corp. 2006). As of 2009, according to its Web site, the company was continuing tar sands development research at it Bartlesville, Oklahoma, facility and was in the process of raising capital for a prototype facility in Utah.

U.S. Oil Sands (Utah) Inc., a U.S. subsidiary of a Canadian company, announced in May 2012 progress on its tar sands efforts in its P.R. Spring area holdings in Uintah County. The company reported completion of an independent bitumen resource assessment of the P.R. Spring area and progress in engineering design work for its commercial bitumen mining project. The company expressed its intentions to begin commercial bitumen production in 2013 using a proprietary bio-solvent process (U.S. Oil Sands 2012).

Temple Mountain Energy has been producing asphalt for road paving and other applications at its operations in Asphalt Ridge in the Uinta Basin since 2006. The company also produces bitumen for road construction as an asphalt binder. The raw bitumen can also be upgraded and sold as low-sulfur crude oil to refiners, who can further refine it to liquid products such as gasoline and diesel. The company also markets the spent sands produced after separation of bitumen for use in a variety of industries, including oil and gas fracturing and for glass making (Temple Mountain Energy 2011).

An application for a commercial tar sands lease covering 2,100 acres on public lands in Asphalt Ridge STSA was submitted to the BLM in 2011 and is currently under review.

B.4 RECOVERY OF TAR SANDS

Recovery methods can be categorized as either mining activities or in situ processes. Mining consists of using surface or subsurface mining techniques to excavate the tar sands with subsequent recovery of the bitumen by washing, flotation, or retorting. In situ techniques recover the bitumen without physically excavating the tar sands. Some techniques combine mining techniques and in situ techniques. In situ recovery is sometimes further categorized as true in situ or modified in situ. True in situ methods generally involve either heating the tar sands or injecting fluids into them to mobilize the bitumen for recovery (Speight 1990, 1995, 1997). There are at least two types of modified in situ methods. The first involves fracturing the tar sands with explosives to increase the permeability of the deposit (National Academy of Sciences 1980); the second process combines true in situ processes with mining techniques (Speight 1990).

Potential Tar Sands Recovery Processes

- Mining
  - Surface
  - Subsurface
- In Situ
  - Thermal
    - Steam and hot water
      - Stimulation
      - Flood
    - Combustion
      - Forward
      - Reverse: wet, dry
    - Electrical
    - Nuclear
  - Nonthermal
    - Diluents
      - Miscible displacement: hydrocarbons, inert gases, carbon dioxide
      - Solvent
      - Chemical: polymer, caustic, surfactant polymer
    - Emulsification
    - Bacterial

Source: Based on Speight (1997).

Depending on production costs and the price of the synthetic crude produced, surface mining operations are generally cost-effective only where the overburden is no more than about 45 m (150 ft) (Meyer 1995). In situ processes requiring high pressures are generally considered to require a thick overburden of about 150 m (500 ft) to contain the pressure. Between these depths, bitumen must be extracted by other means.

B.4.1 Direct Recovery Mining Technologies

Surface mining methods can be used to mine the tar sands for subsequent recovery of bitumen. Subsurface mining has been proposed but has not been applied because of the fear of collapse of the sand deposits (Speight 1990). For this reason, only surface mining is discussed below. However, subsurface mining techniques are employed in some modified in situ recovery methods.

Surface mining requires conventional earthmoving and mining equipment (BLM 1984). Development begins with the construction of access roads and support facilities. Major mining activities during extraction include the following:

- Removing vegetation;

- Stripping, stockpiling, and disposal of topsoil;
- Removing and disposing of overburden;
- Excavating of tar sands; and
- Reclamation of the mined area.

Operations begin with the removal of topsoil and overburden. Topsoil is stockpiled, protected from erosion, and used for reclamation. Erosion and runoff can be reduced by depositing overburden in layers beginning in the bottoms of valleys and building upwards. Later, the deposited overburden can be used for backfilling the pit. It is likely that ultimately the entire area would be disturbed because of actual mining and ancillary activities. Reclamation can proceed as mining progresses and initially mined areas are retired (BLM 1984).

Disposing of waste sand after extraction of the bitumen is a major concern in any surface mining operation (BLM 1984). Although variable, the bitumen content of waste sand can be as high as 5%. Waste sand can be disposed of by (1) backfilling the mined area, (2) filling valleys, or (3) using tailings ponds. Tailings ponds need to be constructed to keep tailings from sliding, to preclude outside runoff from entering the ponds, and to control seepage from the ponds.

In Utah, less than 15% of the tar sands may be shallow enough for strip mining; the deposits at the Asphalt Ridge, P.R. Spring, and Sunnyside STSAs appearing to be most suitable (BLM 1984; National Academy of Sciences 1980). The Athabasca deposits are currently being recovered by surface mining.

The equipment used for surface recovery includes a combination of excavation equipment, to remove the sands from their original location, and conveying equipment, to move the excavated sand to another location. Depending upon the approach chosen, tar sands removal equipment can include draglines, bucketwheel excavators, power shovels, scrappers, bulldozers and front-end loaders. Conveying equipment can include belt conveyors, large trucks (typically 150–400 tons), trains, scrapers, and hydraulic systems (Speight 1995).

Surface excavation is conducted by using two basic approaches. The first uses a small number of large, custom-made, expensive bucketwheel excavators and drag lines along with belt conveyors. The second uses a large number of smaller, conventional, less expensive equipment. Initially, the major developers of the Athabasca oil sands in Canada used bucketwheels or draglines, they now use a truck and shovel approach. Truck and shovel mining is more mobile, can be moved more easily to the richest deposits, and requires less maintenance than the custom bucketwheels and draglines. The larger number of units in operation also means that equipment breakdown has much less impact on overall production.

Today, hydrotransport provides an alternative to the use of belt conveyors between the mining pit and the extraction plant (Oil Sands Discovery Center 2006b). The oil sands are crushed at the mine site, mixed with warm water, and moved by pipeline to the extraction plant. Hydrotransport improves efficiency by initiating the extraction of bitumen while the oil sands are

being transported to the extraction plant. However, its application in arid areas such as Utah may be problematic.

Speight (1995) identifies the following possible problems that may be encountered when mining tar sands deposits:

- The clay shale overburden and sand may swell when exposed to fresh water,
- Pit wall slopes may slough off and may need to be controlled by preblasting or excluding heavy equipment from slope crests,
- The abrasive sands cause a high rate of equipment wear, and
- The large quantity of tailings from the extraction process requires disposal.

Table B-2 provides available data describing potential impact-producing factors that could be associated with a tar sands surface mine. These data were derived from information published by Daniels et al. (1981) on the basis of a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah. The table presents the original numbers estimated for the McKittrick project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

Table B-3 provides available data describing potential air emissions from a tar sands surface mine on the basis of data published by Aerocomp, Inc. (1984), for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA. These data may more accurately reflect emissions from a surface mine excavating sandstone-based tar sands deposits as opposed to the emissions presented in Table B-2 for the diatomaceous earth tar sands deposit.

B.4.2 In Situ Methods

Given the environmental problems associated with mining and the fact that the majority of tar sands lie under an overburden too thick to permit their economic removal, nonmining recovery of bitumen may be a practical alternative. This is especially true in U.S. deposits where the terrain and the character of the tar sands may not be favorable for mining. However, the physical properties of Utah tar sands and the bitumen may constrain application of nonmining methods; Utah sands tend to be low-porosity, low-permeability, consolidated to unconsolidated sands, and the bitumen does not flow under reservoir conditions. Low permeability and porosity require fluids to be injected at pressures sufficient to cause fracturing, which can result in

TABLE B-2 Potential Impact-Producing Factors Associated with a Tar Sands Surface Mine Operating at a Diatomaceous Earth Tar Sands Deposit

	Production Capacity (bbl/day syncrude)[b,c]			
Impact-Producing Factor[a]	20,000	25,000	50,000	100,000
Total land disturbance (acres)	1,000	1,250	2,500	5,000
Water use (bbl/day)[d]	25,160	31,450	62,900	125,800
Noise (dBA at 500 ft)	61	–[e]	–	–
Processed sand (tons/day)	52,000	65,000	130,000	260,000
Air emissions (tons/yr)[f]				
Mining equipment				
TSP	70	87	174	348
SO_x	70	87	174	348
NO_x	905	1,131	2,262	4,524
CO	383	479	957	1,914
THC	104	131	261	522
Crushing apparatus[g]				
TSP	7	9	17	35
Mine pit and storage[h]				
TSP	1,009	1,262	2,523	5,046
THC	35	44	87	174

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; THC = total hydrocarbons (includes methane and photochemically nonreactive compounds); TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter).

[b] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[c] Data taken from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[d] Approximately 3.5% of the process water would need to be fresh water (Daniels et al. 1981).

[e] A dash indicates noise level determined by modeling, not by extrapolation.

[f] The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

[g] Assumes 99.5% emissions control via the baghouse.

[h] Assumes 80% dust suppression by virtue of the natural oil in the tar sands combined with water application.

TABLE B-3 Potential Air Emissions from a Surface Mine Operating at a Sandstone-Based Tar Sands Deposit[a]

	Production Capacity[c,d]			
Air Emissions[b]	20,000 bbl/day syncrude (tons/yr)	32,500 bbl/day syncrude (tons/yr)	50,000 bbl/day syncrude (tons/yr)	100,000 bbl/day syncrude (tons/yr)
TSP	2,814	4,573	7,035	14,071
SO_x	335	544	837	1,674
NO_x	5,276	8,573	13,189	26,378
CO	1,047	1,701	2,617	5,234
VOC	338	549	322	1,689

[a] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

[b] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter); VOC = volatile organic compound.

[c] bbl = barrel; 1 bbl syncrude = 42 gal.

[d] The air emissions data were derived from information published by Aerocomp, Inc. (1984) for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

undesirable flow pathways (e.g., direct communication between the injection well and the production well) (Speight 1990).

In situ or nonmining methods are basically enhanced or tertiary oil recovery techniques that require injecting a “heating” and “driver” substance into the tar sands formation through injection wells to reduce the viscosity of and displace the bitumen so that it can be recovered through conventional liquid production wells (Speight 1997). For a given technique, there could be considerable variation in the efficiency of extracting bitumen between different sites, for example, between water-wet Athabasca sands and oil-wet Utah sands (BLM 1984).

All in situ recovery processes must perform the following:

- Establish fluid flow between injection and production wells;
- Reduce the viscosity of the bitumen by heating it or dissolving it in a solvent so that it will flow to the production well; and
- Maintain the flow of bitumen after it has started.

Heat could be supplied either from steam from surface boilers or by combustion of part of the bitumen in situ. In addition, the deposit should be permeable or susceptible to fracturing to make it permeable and reasonably stable so that it does not compact structurally (i.e., collapse) and lose permeability as bitumen is removed (BLM 1984).

Briefly, development of an in situ facility would include the following processes:

- Exploration to characterize the formation hydrogeologically;
- Drilling of injection and production wells;
- Installation of production equipment;
- Recovery, processing, and upgrading of bitumen to produce synthetic crude oil;
- Removal of equipment at the close of operations; and
- Reclamation.

Numerous, closely spaced holes would be required for injection and production wells, with production wells probably spaced within 150 m (500 ft) of each other. The exact number and the spacing of the wells would be governed by the characteristics of the formation. Surface equipment would vary by the method used but would include drilling rigs, compressors, pumps, piping, storage tanks, waste pits, and pits or tanks for drilling fluids and process water storage and recycling. For most processes, especially those involving steam injection, boilers and steam pipes would also be required. Facilities for treating condensate and water for recycling would also be needed. Ancillary facilities could include shops, warehouses, offices, outside storage areas, fuel storage, housing, and roads (BLM 1984).

Over time, different parts of the site would be developed, and production equipment would be moved from one area to another as the recoverable bitumen was exhausted. Upgrading equipment would be centrally located and would probably not be moved over the life of the site. After the production equipment had been moved, the depleted site could be reclaimed. The amount of surface disturbance from development of in situ recovery facilities would depend on topography and the characteristics of the bitumen and the surrounding rock. Estimates of surface disturbance range from 10 to 60% of the site and are expected to be similar for most in situ methods. The use of directional drilling techniques tends to reduce the amount of surface disturbance (BLM 1984). In addition to the disturbances resulting directly from surface activities, subsidence may also occur and require remediation.

B.4.2.1 Combustion Processes and Modifications

In combustion processes, the bitumen itself is ignited. Once ignition has been achieved, partial or complete combustion must be maintained for a period of about 30 to 90 days.

Temperatures can range from about 600 to 1,200°F. Control of the amount of air injected regulates the rate at which bitumen is burned and hence the temperature. Several regions exist within the reservoir. Just ahead of the fire front, heat breaks the oil down (by cracking and distillation). The cracking provides a partial upgrading of the bitumen recovered from the production wells. Lighter fractions of the bitumen vaporize and move toward cooler portions of the formation and exchange their heat with it, displacing some of the bitumen and increasing recovery efficiency. As the vapors move into cooler parts of the deposit, they condense and can be pumped out of production wells. Condensation could cause a problem by plugging the deposit. Heavier fractions remain behind as coke that includes heavy hydrocarbons containing oxygen, sulfur, nitrogen, and trace metals. Coke may account for up to 20% of the oil and provides most of the combustion fuel. The burned region consists mostly of sand (Schumacher 1978; Speight 1990, 1997).

The use of combustion or fire flooding to stimulate bitumen production may be attractive for deep reservoirs because little heat is lost. Conversely, heat loss limits the use of steam injection in deep reservoirs. The high pressures involved in injecting combustion air preclude the use of combustion in shallow deposits. Another advantage of combustion over steam-based processes is the reduction of carbon dioxide (CO_2) emissions from aboveground steam generators. However, CO_2 from in situ combustion will be present in the produced gases recovered from production wells. Combustion has been effective in the recovery of heavy oils from thick reservoirs where the dip and continuity of the formation may assist gravity flow of bitumen or where wells can be closely spaced (Schumacher 1978; Speight 1990, 1997; Isaacs 1998).

With the exception of the fuel needed to initiate combustion, there is no need to buy fuel to produce heat in the well (Schumacher 1978). However, any bitumen in the combusted coke cannot be recovered as product. Some of the advantage also is lost by the need to compress the injection air and the increased loss of heat to the formation at the elevated temperatures associated with burning. This loss can be reduced by injecting water at the same time or alternatively with the combustion air.

Far less experience and information are available for in situ combustion than for steam processes, and process control is more difficult. Some considerations include:

- Sufficient bitumen must be consumed to raise the temperature enough to mobilize the remaining bitumen,
- Sufficient oxygen must be supplied to support and control combustion,
- Overburden and underburden must provide effective seals for injected air and mobilized bitumen and serve as effective barriers to heat loss (Speight 1990).

The combustion in in situ processes can be categorized as forward, reverse, or a combination of forward and reverse. In forward combustion (Figure B-3), the fire front is ignited at the injection well and moves toward the production well. As the bitumen moves toward the production well, it moves from the zone of combustion into a colder, unheated portion of the

formation. Because the bitumen is generally less mobile when it is colder, the forward combustion process has an upper limit on the viscosity of liquids that can be recovered. Up to 80% of the combustion heat remains behind the advancing fire front and is lost. However, because the air passes through the hot formation behind the flame front prior to reaching the combustion zone, combustion efficiencies are enhanced and more unburned hydrocarbons are recovered. Heavier components are left on the sand grains and consumed as fuel. Deposits with relatively high permeability and relatively low bitumen saturation (45–65 vol%) are most amenable to this process. Forward combustion has been used with some success in the Orinoco deposits in Venezuela and in Kentucky sands (Schumacher 1978; Speight 1990, 1997; Meyer 1995).

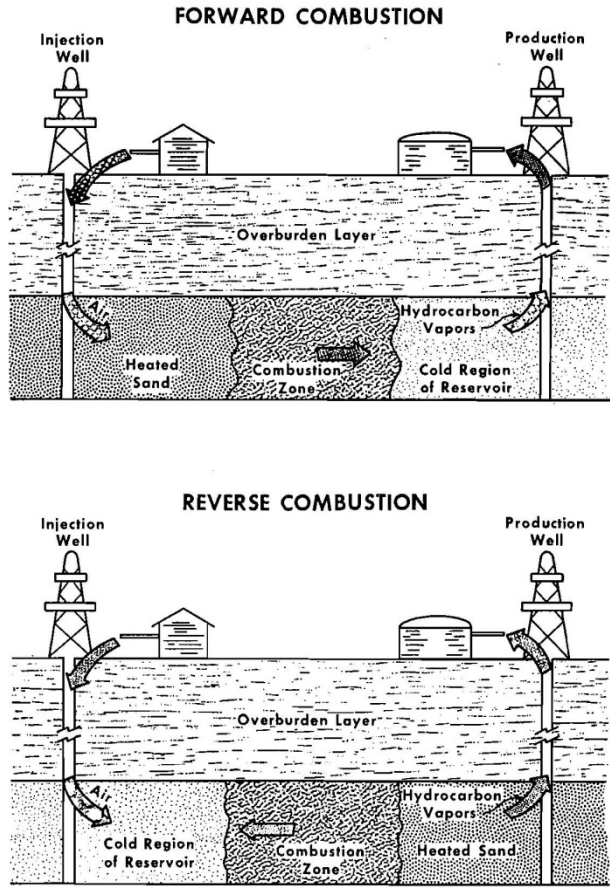

FIGURE B-3 Simplified Diagrams of Forward and Reverse Combustion Processes (Speight 1990) (Copyright 1990 from *Fuel Science and Technology Handbook* edited by James G. Speight. Reproduced by the permission of Routledge/Taylor & Francis Group, LLC.)

In reverse combustion (Figure B-3), the fire front is ignited at the production well and moves toward the injection well. Combustion air introduced at the injection well helps drive the volatile organics toward the production well. Because combustion products and product move into the hot zone behind the fire front, there should be less of a viscosity limitation. Residual coke would remain on the sand grains. This process is most applicable to deposits with lower permeability because movement of mobilized fluids would be into a hot zone with a consequent reduction in plugging (Speight 1990, 1997; Meyer 1995).

In a combination of reverse and forward combustion, the initial phase uses a low-temperature reverse combustion to increase the permeability of the formation and increase the mobility of the bitumen. The subsequent forward combustion phase supplies the heat and energy to distill and mobilize the bitumen and move it to the production wells (Marchant and Westhoff 1985).

Modifications of the in situ combustion process include fracturing by either pneumatic or hydraulic means to increase permeability of reservoirs so that combustion air can flow more freely. In another modification, oxygen or oxygen-enriched air rather than atmospheric air is injected under certain conditions. Cost savings accrue because of the reduced compression costs and the reduction in the gas-to-oil ratio in the recovered product.

In the wet combustion modification, water and air are injected alternatively into the formation. The water flows through the fire, vaporizes, and then condenses, thereby heating the unburned deposit and reducing the viscosity of the bitumen. Wet combustion can move heavier oils and operate at lower pressures than dry combustion and may burn less bitumen, resulting in a reduced need for injected air (Schumacher 1978; Speight 1990, 1997).

A combination of forward combustion and waterflooding has also been tried at Athabasca. It involved a heating phase followed by a production or blowdown phase followed by a displacement phase using a fire-water flood, over a period of 18 months (8 months heating, 4 months blowdown, and 6 months displacement) (Speight 1990).

Table B-4 provides available data describing potential impact-producing factors that could be associated with in situ combustion processes. The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 20,000-bbl/day-capacity project in the Circle Cliffs STSA (based upon parameters for an oil shale processing facility) and include emissions from upgrading processes. The nonair emissions data were derived from information published by Daniels et al. (1981) on the basis of the proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The table presents the original numbers estimated for each project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

B.4.2.2 Noncombustion Processes

The noncombustion processes discussed in this subsection involve the injection of liquid or gas into the reservoir to effect the mobilization and recovery of the bitumen. For steam injection processes, the cost of generating steam is the most significant expense. Also, the feedwater must be of relatively high quality (Speight 1990), which could prove to be an obstacle to using steam injection processes in the arid and semiarid regions of Utah.

Steam drive (steam flood) processes (Figure B-4) involve the injection of steam from surface boilers into at least one injection well with the recovery of the mobilized bitumen and condensed steam from at least one production well. The wells could be placed either in parallel rows or in a ring around a central well. Heat released by condensing steam reduces the viscosity of the bitumen, which is forced to the production well by the flow of steam and hot water. In situ distillation (upgrading) and improved gas drive are side benefits of this steam drive. This process may be used following cyclic steam injection. The permeability of the reservoir must be sufficient to permit the injection of steam at rates high enough to raise the temperature to the point at which the bitumen will flow. Permeability will decrease as the process proceeds and water and steam saturate the reservoir; as permeability decreases, the amount of injected steam required to produce a unit of oil increases sharply. Establishing communication between the injection and production wells presents a problem for this technique, but it has been successfully utilized by Shell Canada in the Peace River deposit in Alberta. Bitumen-to-water ratios could be as high as 1 to 10 but are generally around 1 to 5. The use of steam has been demonstrated with

TABLE B-4 Potential Impact-Producing Factors Associated with In Situ Combustion Processes

	Production Capacity (bbl/day syncrude)[b,c]			
Impact-Producing Factor[a]	20,000	25,000	50,000	100,000
Total land disturbance (acres)	4,000	5,000	10,000	20,000
Produced wastewater (bbl/day)[d]	40,000	50,000	100,000	200,000
Air emissions (tons/yr)				
Stack emissions[e]				
TSP	438	548	1,095	2,190
SO_x	4,960	6,200	12,400	24,800
NO_x	2,052	2,565	5,130	10,260
CO	60	75	150	300
VOC	110	138	275	550
Fugitive emissions[f]				
TSP	409	511	1,022	2,045
SO_x	4	5	10	20
NO_x	7	9	18	35
CO	48	60	120	240
VOC	2	3	5	10

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter); VOC = volatile organic compound.

[b] The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 20,000-bbl/day-capacity project in the Circle Cliffs STSA (based upon parameters for an oil shale processing facility). Nonair emissions data were derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Based upon an estimated generation rate of 1 to 2 bbl of wastewater per bbl of syncrude produced.

[e] Modeled on the basis of the following: stack height = 76 m (249.3 ft), stack diameter = 3 m (9.8 ft), velocity = 10 m/s (32.8 ft/s), and temperature = 311K (100.1°F).

[f] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

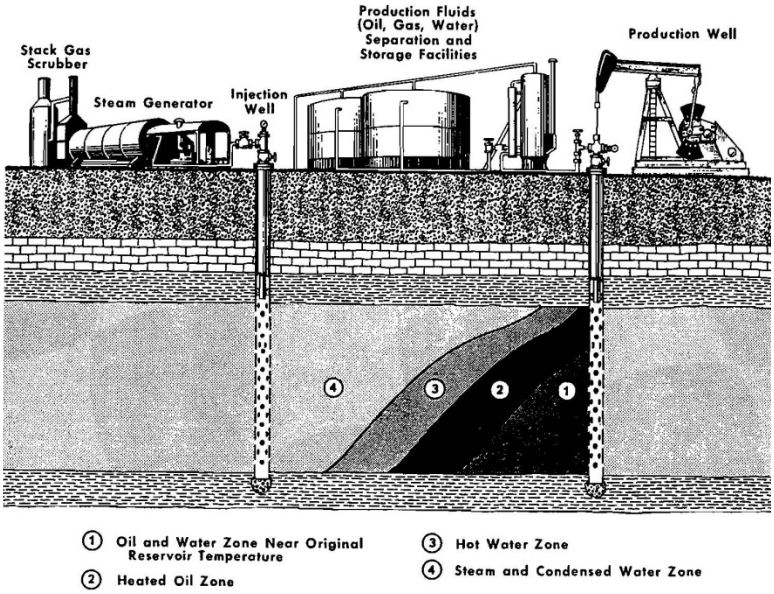

FIGURE B-4 Simplified Steam Drive Process (Speight 1990) (Copyright 1990 from *Fuel Science and Technology Handbook* edited by James G. Speight. Reproduced with the permission of Routledge/Taylor & Francis Group, LLC.)

some success in Utah sands. The large amount of energy required to generate, compress, and pump steam presents an important technical requirement for steam drive (Spencer et al. 1969; Schumacher 1978; National Academy of Sciences 1980; BLM 1984; Speight 1995; Isaacs 1998).

The alternative cyclical steam stimulation, also known as "huff and puff," involves injecting high-temperature (about 350ºC [660ºF]) steam from surface boilers at higher than fracturing pressure into the deposit over a period ranging from days to months, followed by a "soak" period of variable length, followed by production for up to a year. Initial production relies on the pressure created by injection followed by pumping (Speight 1990, 1997; Oils Sands Discovery Center 2006b). Cyclic steam has more effect on increasing the rate of production than on increasing the ultimate recovery (Schumacher 1978).

Another steam injection approach, SAGD, is most suitable for reservoirs with immobile bitumen. It involves drilling two horizontal wells at the bottom of a thick unconsolidated sandstone reservoir. Steam is injected continuously through the upper well at pressures much lower than the fracture pressure. Heat and steam rise and condensed water and mobilized oil flow down by gravity into the lower or production well. As the process proceeds, a "steam chamber" develops laterally and upwards. SAGD seems to be insensitive to horizontal barriers to flow such as shale intrusions that fracture from thermal shock. Recovery ratios of 50 to 75% may be achievable; however, the initial oil recovery rate is low.

The uses of hot fluids, steam, water, and gas for injection are similar. Hot water is more efficient than hot gas but less efficient than steam mainly because of the relative heat-carrying

capacities of the fluids. Nonsteam techniques have been applied to bitumen recovery in conjunction with other techniques (Spencer et al. 1969; BLM 1984).

Solvent extraction involves the injection of solvent into the formation to dissolve the bitumen and carry it to a production well for pumping to the surface. At the surface, the bitumen is separated from the solvent and the solvent is recovered. When applied in situ, large losses of solvent and bitumen have always presented major problems that must be controlled. In addition, the only useful solvents, at least for Athabasca bitumen, are relatively expensive naphthenic and aromatic substances. Solvent extraction has not generally been economical compared with steam injection.

Two aqueous emulsifying systems have been developed for use in the Athabasca sands (Spencer et al. 1969). One employs an alkaline surfactant solution, the other a dilute sodium hydroxide solution. Field tests showed that bitumen was completely removed from the contacted portion of the reservoir but that the contacted portion was very limited because of the low permeability of the reservoir.

Several variations of steam heating and emulsification have been tried (Speight 1990). These include the use of steam with various solvents to reduce the viscosity of the oil through a combination of heating and dissolution. A technique involving fracturing by using dilute aqueous alkaline solutions followed by emulsification with hot caustic and production of an emulsion by using steam injection at the production wellhead was used in the Athabasca sands. It was estimated that more oil had leaked away from the recovery zone than had been recovered.

Many additional processes are in the concept or early development phase or for which patents have been sought or issued. Some of those that potentially could be applied within the 20-year planning horizon of this PEIS include the following:

- *Top-Down Combustion*, in which combustion would be initiated and maintained by the injection of air at the top of the reservoir with the heated, mobilized oil draining into horizontal wells by gravity (Isaacs 1998).

- *Cyclic Steam Combined with Steam-Assisted Gravity Drainage Gravity* (Isaacs 1998).

- *Warm Vapor Extraction*, which involves the injection of vaporized solvents to create a vapor chamber through which mobilized hydrocarbons flow because of gravity drainage.

- *Toe-to-Heel Air Injection*, which combines a vertical air injection well with a horizontal production well. A combustion front is created and combusts part of the hydrocarbon in the reservoir. The heat generated reduces the viscosity of the hydrocarbon that is pulled to the horizontal production well by gravity. The combustion front moves from the “toe,” the underground end of the horizontal production well, to the “heel,” where the production well transitions from horizontal to vertical.

- *Pressure Pulse Flow Enhancement Technology*, which is based on the recent discovery that large-amplitude, low-frequency energy waves can enhance flow rates in porous media (Dusseault 2001).

- *Nuclear Energy*, which has been proposed as an energy source for producing a combination of steam and electricity for tar sands recovery while reducing CO_2 emissions (Donnelly and Pendergast 1999; Dunbar and Sloan 2003).

Table B-5 provides available data describing potential impact-producing factors that could be associated with in situ steam injection processes. The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 50,000-bbl/day-capacity project in the P.R. Spring STSA and a proposed 20,000-bbl/day-capacity project in the San Rafael Swell STSA and include emissions from upgrading processes. The nonair emissions data were derived from information published by Daniels et al. (1981) on the basis of the proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The table presents the original numbers estimated for each project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

B.4.3 Modified In Situ Methods

The use of explosives to disaggregate the tar sands and increase permeability is similar to the process used for oil shale (see Appendix A) and is not discussed further here.

As noted above, methods for recovering bitumen from formations located at depths between about 45 and 150 m (150 and 500 ft) are limited. In comparison with surface mining, subsurface mining reduces the need for raw tar sands handling and storage; the need for handling and disposal of spent sand (tailings); and the need for reclamation of a mined out pit, room, or shaft. One potential extraction method applicable at these depths involves combining in situ and subsurface mining techniques. This process, referred to as oil mining, has been used in the past in France, Germany, and Russia and entails underground mining of some of the tar sands deposit so that in situ methods can be used on the remaining deposit. Most commonly, a vertical shaft is sunk and horizontal drifts are excavated from the bottom of the shaft. Horizontal injection and production wells are drilled from the drifts. The drifts can be above or below the tar sands formation and are typically used to permit low-pressure steam to be injected into the formation to heat the sands so that the bitumen will flow (Meyer 1995; Isaacs 1998).

B.5 PROCESSING RECOVERED BITUMEN

The choice of recovery method affects which processing operations are used. In mining operations, the mined bitumen must be processed to recover or separate it from the inorganic matrix (largely sand, silt, and clay) in which it occurs. Nonmining extraction produces bitumen mixed with water, steam, other gases, or solvent from which it must be separated. If combustion

TABLE B-5 Potential Impact-Producing Factors Associated with In Situ Steam Injection Processes

	Production Capacity (bbl/day syncrude)[b,c]		
Impact-Producing Factor[a]	20,000	50,000	100,000
Total land disturbance (acres)	4,000	10,000	20,000
Water use (bbl/day)[d]	100,000	250,000	500,000
Air emissions (tons/yr)			
Stack emissions[e]			
TSP	358	1,155	2,310
SO_x	6,758	16,896	33,792
NO_x	5,332	13,332	26,664
CO	712	1,782	3,564
VOC	356	889	1,778
Fugitive emissions[f]			
TSP	615	895	1,790
SO_x	0	1	2
NO_x	1	2	4
CO	4	11	22
VOC	0.4	1	2

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 µm in diameter); VOC = volatile organic compound.

[b] The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 50,000-bbl/day-capacity project in the P.R. Spring STSA and a proposed 20,000-bbl/day-capacity project in the San Rafael Swell STSA. Nonair emissions data were derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Based upon an estimated use rate of 5 bbl of water per bbl of syncrude produced.

[e] Modeled on the basis of the following: for the 20,000-bbl/day facility, stack height = 76 m (249.3 ft); stack diameter = 5 m (16.4 ft); velocity = 12 m/s (39.4 ft/s); and temperature = 493°K (427.7°F). Modeled on the basis of the following: for the 50,000-bbl/day facility, stack height = 76 m (249.3 ft); stack diameter = 7 m (23 ft); velocity = 12 m/s (39.4 ft/s); and temperature = 473 K (391.7°F).

[f] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

recovery is used, the viscosity of the recovered bitumen may need to be reduced prior to further processing. If steam, water, or gas injection is used, the injection fluid would need to be separated from the bitumen. In all cases, the viscosity of the bitumen might need to be changed prior to further processing and upgrading (BLM 1984). Depending on the recovery method, mining operations may also need to perform similar separations.

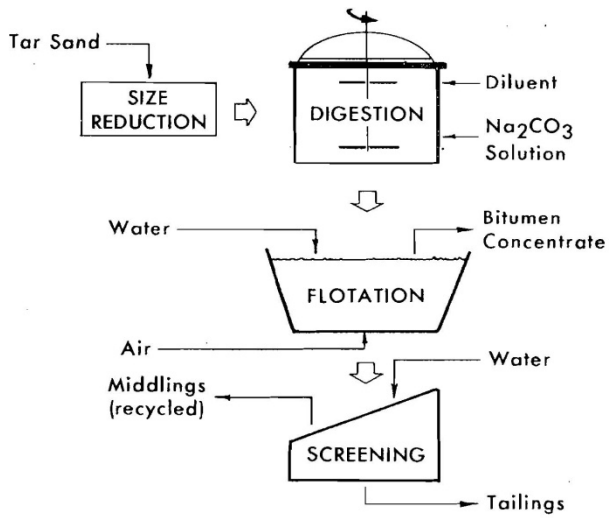

FIGURE B-5 Simplified Diagram of Hot Water Recovery Process (Marchant and Westhoff 1985)

B.5.1 Hot Water Process

The hot water process has been applied with commercial success to mined water-wet Athabasca sands (see Figure B-5). As of 1997, it was the only process to have been applied with commercial success to mined tar sands in North America (Speight 1997). There are three main steps: conditioning, separation, and scavenging.

There are two methods of conditioning. In the first, mined tar sands are pumped with water and caustic into a conditioning drum at 180 to 220°F to reduce particle size and digest the bitumen. The resulting slurry is screened to remove undigested material, and lumps are sent to a separation cell. In the newer hydrotransport method, the tar sands are crushed at the mine site and moved by pipeline in a water slurry to the extraction plant (Marchant and Westhoff 1985; Speight 1997; Oil Sands Discovery Center 2006b).

The separation cell operates like a settling vessel. Sand settles downward to be removed, as tailings and bitumen float to the top where they are skimmed off. Most of the middlings, an emulsion for bitumen and water, are sent to scavenger cells for additional bitumen removal by froth flotation (Marchant and Westhoff 1985; Speight 1997).

Experiments have been conducted to develop a hot water process for the oil-wet tar sands deposits in Utah (Speight 1997; Marchant and Westhoff 1985). The absence of a sheath of water around the tar sands particles and the strong bonding directly between the sand and the bitumen suggest that more energy would be required to separate sand and bitumen in the Utah tar sands than would be required in the Athabasca tar sands. After size reduction, digestion is accomplished using a high shear energy digester stirred at about 750 rpm at 200°F. Next, bitumen is separated by modified froth flotation. Middlings are screened and recycled (Oblad et al. 1987). This process has been developed to the pilot plant stage (Figure B-5), processing 125 tons/day of tar sands to produce 50 to 100 bbl/day of oil (Speight 1990).

Disposal of tailings presents a problem for hot water recovery processes (Speight 1997). The volume of material expands during processing. A ton of in situ tar sands has a volume of about 16 ft^3 and produces about 22 ft^3 of tailings, a volume increase of almost 40%. The tailings

stream contains about 49 to 50 wt% sand, about 1 wt% bitumen, and about 50 wt% water (Speight 1990). Regulations preclude dumping these tailings in streams or rivers or in areas from which runoff may enter rivers or contaminate groundwater. Reclamation of the tailings must also be accomplished upon site closure.

In some operations, recovery of bitumen from the middlings in scavenger cells may be economical, the goal being an additional 2 to 4% bitumen recovery. This process generally involves injecting air in a froth flotation process. Froth containing bitumen rises to the surface of the cell and is skimmed off.

The froths from the separation vessel and the scavenger cells are combined and sent for further processing. The froth stream is usually diluted with naphtha and centrifuged. At this stage, the bitumen contains 1 to 2 wt% minerals and 5 to 15 wt% water and is ready for upgrading.

B.5.2 Cold Water Process

Operations in the Athabasca tar sands have changed from hot water processing to cold water processing, which uses less energy. This change was made possible by using slurry pipelines rather than belt conveyors to transport ore from the mine to the extraction facility. Mined sand is crushed at the mine site, mixed with warm water to form a slurry, and moved by pipeline to the extraction plant. Partial separation of the bitumen from the sand occurs in the pipeline (Singh et al. 2005; Oil Sands Discovery Center 2006b).

Experiments with cold water extraction of Utah tar sands showed a removal of more than 60% of the sand with easily accomplished water removal. Calculations indicated that for 90% recovery of the bitumen, hot water processing would require at least 45 kWh/ton, while cold water processing would require only 13 kWh/ton (Oblad et al. 1987).

Bench-scale cold water processes have also been developed. The sand reduction process uses cold water and no solvent to provide a feed for a fluid coking upgrading process. Tar sands are mixed with water in a screw conveyor and discharged to a screen of appropriate mesh in a water-filled settling vessel. Bitumen agglomerates on the screen and is removed while the sand passes through and is removed as waste.

In the spherical agglomeration process, water is added to the tar sands and the mixture is sent to a ball mill. The bitumen agglomerates to particles with at least 75 wt% bitumen (Speight 1990, 1997).

B.5.3 Processes Involving Solvents

Solvent extraction without water has been attempted. It generally uses a low boiling point hydrocarbon (such as heptane, cyclohexane, or ethanol) and involves four main steps. Fresh tar sands are mixed with recycled solvent containing some bitumen, water, and minerals. Next, a

three-stage countercurrent wash is used with settling and draining of about 30 minutes after each stage forming a bed of sand through which the bitumen containing solvent is drained. The last two steps recover the solvent from the sand. Solvent extraction has been demonstrated for Athabasca, Utah, and Kentucky sands, but the cost of solvent losses has kept the process from going commercial (Speight 1997).

Experiments have been carried out on various tar sands deposits, including those at the Asphalt Ridge and Sunnyside STSAs, by using kerosene to control the viscosity of the bitumen to improve bitumen recovery and tailings sedimentation. The temperatures involved have been lowered from near the boiling point of water 100°C (212°F) to around 50 to 55°C (120–130°F). More than 92% of the bitumen in the concentrate was recovered (Oblad et al. 1987).

The cold water bitumen separation process using a combination of cold water and a solvent has been used in a small-scale pilot plant (Speight 1997). The tar sands are first mixed with water, reagents, and a diluent, which may be a petroleum fraction such as kerosene. The solution is maintained in an alkaline condition. Then sand is removed by settling in a clarifier from which the water and oil overflow is sent to thickeners to concentrate the oil. Clay in the feed emulsifies and carries off some of the bitumen as waste from the thickeners.

Table B-6 provides available data describing potential impact-producing factors that could be associated with solvent extraction processes. The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA and include emissions from upgrading processes. The nonair emissions data were derived from information published by Daniels et al. (1981) on the basis of the proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The table presents the original numbers estimated for each project and extrapolated numbers for larger or smaller operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

B.5.4 Thermal Recovery Processes

Various schemes have been proposed as alternatives to the hot water process to remove bitumen from mined tar sands by applying heat. Direct coking or thermal recovery processes appeared promising but the success of hydrotransport in making cold water extraction commercially successful in Athabasca has helped reduce the attractiveness of thermal recovery, which can require consumption of a substantial amount of heat (Marchant and Westhoff 1985).

In most processes, the tar sands are pyrolyzed (heated in an inert or nonoxidizing atmosphere) by heating at 900°F to effect chemical changes, including

- Volatilization of low molecular weight components,
- Cracking of some heavier components, and

TABLE B-6 Potential Impact-Producing Factors Associated with a Solvent Extraction Facility

	Production Capacity (bbl/day syncrude)[b,c]			
Impact-Producing Factor[a]	20,000	32,500	50,000	100,000
Total land disturbance (acres)	2,600	4,225	6,500	13,000
Water use (bbl/day)[c,d]	106,930	173,760	267,330	534,650
Noise (dBA at 500 ft)	73–88	–[e]	–	–
Air emissions (tons/yr)[e,f]				
Extraction plant[e]				
TSP	422	686	1,055	2,110
SO_x	632	1,027	1,580	3,161
NO_x	4,990	8,109	12,475	24,950
CO	239	389	598	1,196
VOC	118	193	296	592
Upgrading plant[g]				
TSP	139	225	346	693
SO_x	94	153	235	470
NO_x	4,522	7,348	11,305	22,610
CO	217	352	542	1,084
VOC	107	174	268	537
Spent tar sands[h]				
TSP	825	1,340	2,062	4,123
SO_x	46	75	115	231
NO_x	750	1,218	1,874	3,748
CO	129	209	322	643
VOC	39	63	97	194

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter); VOC = volatile organic compound.

[b] The air emissions data were derived from information published by Aerocomp, Inc. (1984), for a proposed 32,500-bbl/day-capacity project in the Sunnyside STSA. Nonair emissions data were derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Approximately 22% of the process water would need to be fresh water (Daniels et al. 1981).

[e] A dash indicates noise level not calculated.

[f] Modeled on the basis of the following: height above ground surface = 3 m (9.8 ft) and area = 2,000 m^2 (2,392 yd^2).

Footnotes continued on next page.

TABLE B-6 (Cont.)

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[g] Modeled on the basis of the following: stack height = 33 m (108.3 ft), stack diameter = 5 m (16.4 ft), velocity = 12 m/s (39.4 ft/s), and temperature = 393 K (247.7°F). Values derived from the original source on basis of relative emission rates provided (see Table 5-5, Aerocomp, Inc. 1984).

[h] Modeled on the basis of the following: stack height = 55 m (180.4 ft), stack diameter = 6 m (19.7 ft), velocity = 12 m/s (39.4 ft/s), and temperature = 393K (247.7°F). Values derived from the original source on the basis of relative emission rates provided (see Table 5-5, Aerocomp, Inc. 1984).

- Conversion of part of the bitumen to coke.

The volatile materials exit the reaction vessel, are cooled, and separated into gases and condensed liquids while the coke remains behind adhering to the sand, which is transferred to a combustion vessel for burning to provide heat for the process. In general, the oil obtained by a thermal process would require upgrading before it is acceptable as a refinery grade synthetic crude. The sulfur- and nitrogen-containing compounds must be eliminated, the nitrogen and/or sulfur converted to compounds that are subsequently removed (typically ammonia and hydrogen sulfide, respectively) and further processed into saleable commodities or disposed of as waste, the average molecular weight lowered, and the carbon-to-hydrogen ratio reduced (Marchant and Westhoff 1985; Speight 1990).

About a dozen other thermal processes have been described in the literature. Experiments utilizing fluidized bed pyrolysis have been conducted on Utah tar sands at the University of Utah (Marchant and Westhoff 1985; Speight 1997).

Table B-7 provides available data describing potential impact-producing factors that could be associated with a surface retort facility. These data were derived from information published by Daniels et al. (1981) on the basis of a proposed 20,000-bbl/day-capacity plant designed for the recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. The proposed retort facility was a Lurgi-Ruhrgas retort. The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah. The table presents the original numbers estimated for the McKittrick project and extrapolated numbers for larger operations. It should be noted that the numbers were extrapolated linearly because no information is available to justify doing otherwise; linear extrapolations are likely to result in conservative overestimates of potential impacts.

TABLE B-7 Potential Impact-Producing Factors Associated with a Surface Retort Facility

	Production Capacity (bbl/day syncrude)[b,c]			
Impact-Producing Factor[a]	20,000	25,000	50,000	100,000
Total land disturbance (acres)	2,600	3,250	6,500	13,000
Water use (bbl/day)[d]	11,950	14,940	29,880	59,760
Noise (dBA at 500 ft)	73–88	–[e]	–	–
Air emissions (tons/yr)				
Retort[f]				
TSP	954	1,192	2,384	4,768
SO_x	1,002	1,253	2,506	5,011
NO_x	393	492	983	1,966
Fuel burning equipment[g]				
TSP	21	26	52	104
SO_x	24	30	61	122
NO_x	104	131	261	522
CO	17	22	44	87
THC	3	4	9	17
Storage tanks[h]				
THC	28	35	70	140
Valves, pumps, compressors[i]				
THC	3	4	9	17

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides; THC = total hydrocarbons (includes methane and photochemically nonreactive compounds); TSP = total suspended particulates (includes all particulate matter up to about 100 μm in diameter).

[b] Data derived from Daniels et al. (1981) for a proposed 20,000-bbl/day-capacity plant designed for recovery of oil from a diatomaceous earth tar sands deposit near McKittrick, California. Numbers for larger production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Approximately 100% of the process water would need to be fresh water (Daniels et al. 1981).

[e] A dash indicates noise level not calculated.

[f] These data are based upon a Lurgi-Ruhrgas retort operating with a 97% efficient lime injection and scrubbing system to control SO_x emissions and a 99.5% efficient electrostatic precipitator to control TSP emissions. These data were modeled on the basis of the following: stack height = 76 m (249.3 ft), volume = 193.4 m^3/s (2,081.7 ft^3/s), and temperature = 88°C (190.4°F). The particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

Footnotes continued on next page.

TABLE B-7 (Cont.)

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[g] The fuel burning equipment includes a distillation furnace, hydrogen plant, and hydrogenation unit and includes a 50% efficient ammonia injection system to control NO_x emissions. These data were modeled on the basis of the following: stack height = 76 m (249.3 ft), volume = 22 m^3/s (236.8 ft^3/s), and temperature = 88°C (500°F). The volatile emissions data presented in this table are likely to exceed those that would be expected from one of the Utah tar sands deposits because the bitumen is more volatile at McKittrick. In addition, the particulate emissions are likely to exceed emissions from a Utah deposit because the diatomaceous earth tar sands at McKittrick are less tightly bound than the sandstone deposits in Utah.

[h] Equipped with a double-sealed floating roof.

[i] Assumes equipment is subjected to a strict maintenance program.

B.6 UPGRADING

Upgrading recovers the light components from the recovered bitumen and changes the heavy components into synthetic crude oil. By-products, which can be used directly or as raw materials for other processes, are also produced. Bitumen has a higher carbon-to-hydrogen ratio than crude oil. Some upgrading processes remove carbon (e.g., a coking operation) and others add hydrogen (e.g., a hydrogenation that converts unsaturated hydrocarbons in the saturated analogs) to reduce this ratio. Upgrading also decreases the specific gravity (density) of the synthetic crude oil to a level suitable for a refinery feedstock. Although there are variations between different production operations, four main processes are used to upgrade bitumen: coking (thermal conversion), catalytic conversion, distillation (fractionation), and hydrotreating (Speight 1990, 1997; Meyer 1995; Oil Sands Discovery Center 2006b).

The recovery process has a determining influence on the ancillary processes associated with upgrading. If combustion recovery were used, the viscosity of the bitumen might need to be reduced prior to upgrading. If a steam, hot water, or hot gas injection were used, the injected fluids would probably need to be separated from the recovered bitumen/fluid mixture. In addition, the viscosity of the bitumen might need to be reduced. Similarly, if solvent recovery were used, the solvent and bitumen would need to be separated and the viscosity of the bitumen might need to be reduced (BLM 1984).

Limited data are available to describe the potential impact-producing factors that could be associated strictly with upgrading processes; usually, the data are provided for an entire plant, including extraction and upgrading facilities. Table B-8 provides data describing potential impact-producing factors that could be associated with the upgrading facilities used for processing oil shale—specifically, The Oil Shale Corporation (TOSCO) II aboveground retort facility. Given that kerogen oil (raw shale oil) derived from oil shale requires more extensive upgrading than bitumen recovered from tar sands, these data are likely to result in conservative overestimates of potential impacts. These data were derived from information published by the

TABLE B-8 Potential Impact-Producing Factors Associated with Upgrading Facilities

Impact-Producing Factor[a]	Production Capacity (bbl/day syncrude)[b,c]			
	25,000	47,000	50,000	100,000
Water use (bbl/day)[d]	481,910	906,000	963,830	1,927,660
Air emissions (tons/yr)				
Particulates	31	58	62	123
SO_x[e]	271	510	542	1,085
NO_x	221	416	442	885
CO	27	51	54	108
Hydrocarbons	5	9	10	19

[a] CO = carbon monoxide; NO_x = nitrogen oxides; SO_x = sulfur oxides.

[b] Data derived from DOE (1983) for a proposed 47,000-bbl/day-capacity TOSCO II aboveground retort (indirect mode) for production of syncrude from oil shale. Numbers for larger and smaller production capacities were extrapolated linearly, which is likely to result in conservative overestimates of potential impacts.

[c] bbl = barrel; 1 bbl syncrude = 42 gal, 1 bbl water = 55 gal.

[d] Represents evaporative losses from the coker unit.

[e] Includes emissions from tail gas incinerator.

DOE (1983) on the basis of a 47,000-bbl/day syncrude facility, including hydrogenation and hydrotreating units.

B.6.1 Coking (Thermal Conversion)

The molecules in recovered bitumen must be reduced in average molecular weight. If heated to high temperatures, long, heavy hydrocarbon molecules break apart into shorter, lighter molecules. This process is called cracking and proceeds faster at higher temperatures (Meyer 1995; Oil Sands Discovery Center 2006c). There are two types of coking: delayed coking and fluid coking. Suncor uses delayed coking, and Syncrude uses fluid coking in its Athabasca operations.

Delayed coking is a batch process. Recovered bitumen is heated to 925°F and pumped into one side of a double-sided coker where it cracks into vapor and coke. The vapors escape from the vessel for condensation and further processing, and the coke remains behind. In about 12 hours, the first side is full of coke and the cracking operation shifts to the other side. The solid coke is cut out by use of a water drill (Oil Sands Discovery Center 2006b).

Fluid coking is a continuous process. Bitumen is heated to 925°F (500°C) and blown into a vessel containing small spheres of coke suspended in an upward flow of steam. The large molecules in the bitumen are cracked, and the resulting smaller molecules are carried out of the top of the vessel as a vapor for condensation and further processing. The remaining coke agglomerates with the coke spheres, which eventually become large enough to settle to the bottom of the vessel from which they are removed. At the Syncrude operation, the process recovers about 86 bbl of synthetic crude for every 100 bbl of recovered bitumen. In another variation, the heated bitumen is sprayed into the entire height and circumference of the vessel and cracks into a gas that is removed from the top of the vessel and a fine coke powder that is removed from the bottom (Meyer 1995; Oil Sands Discovery Center 2006b).

Both fluid and delayed coking produce coke, distillate oils, and light gases. Upwards of 75% of the bitumen is converted to liquids, with fluid coking giving 1 to 5% more than delayed coking. Most of the coke is used to produce heat for the upgrading operations. More is produced than is needed and is stockpiled for storage. Sulfur occurs throughout the distillates from both processes. Nitrogen occurs in all fractions but is concentrated in the higher boiling point fractions. Naphtha and gas oil require the addition of hydrogen to be suitable as refinery feeds (Speight 1997; Oil Sands Discovery Center 2006b).

B.6.2 Catalytic Conversion

Catalytic conversion is really a thermal conversion enhanced by using catalysts. Catalysts help chemical reactions occur but are not themselves chemically changed by the reactions. For a catalyst to be effective, the hydrocarbon molecules in the bitumen must contact the so-called active sites on the catalyst. When large hydrocarbon molecules contact the active sites, they crack into smaller molecules. The catalyst also impedes the progress of larger hydrocarbon molecules so that they can continue to crack into smaller pieces. In hydroprocessing, hydrogen is added to the process to improve the carbon-to-hydrogen ratio (Oil Sands Discovery Center 2006b).

B.6.3 Distillation (Fractionation)

Distillation is a very common refinery process. The functioning of a distillation tower depends on the fact that different substances boil at different temperatures. The tower is essentially kept hotter at the bottom and cooler at the top. Vapors collected from the coker are introduced at the bottom and rise up through the tower. Heavier hydrocarbons with higher boiling points condense near the bottom of the tower. Lighter hydrocarbons with lower boiling points move upward and condense at different levels depending on their boiling points. The condensed liquids are removed from the tower (Oil Sands Discovery Center 2006b).

An efficiency gain is realized in processing bitumen if the output of the coker is separated into several streams for additional processing. In particular, the naphtha component requires special processing. At Suncor, the coker distillate is distilled into three fractions: naphtha, kerosene, and gas oil. At Syncrude, the coker distillate is distilled into two fractions: naphtha and

mixed gas oil. The products of additional processing, including hydrotreating, are blended to produce synthetic crude oil (Speight 1997).

B.6.4 Hydrotreating

Hydrotreating is used on the gas oils, kerosene, and naphtha resulting from the upgrading of bitumen. It is one of the most commonly used chemical processes for adding hydrogen to organic molecules. In hydrotreating, the feedstock is mixed with excess hydrogen at high pressure and temperatures of 300 to 400°C (570 to 750°F) in the presence of catalysts. The process can also remove sulfur, nitrogen, and metals as well as undesirable organics from the feedstock. The addition of hydrogen also helps stabilize the produced synthetic crude so that its chemical composition does not change in transit between the syncrude plant and the refinery. In the production of synthetic crude oil, the gases from hydrotreating (all of which are typically flammable) are usually desulfurized and used as fuels on-site (Meyer 1995; Speight 1997; Oil Sands Discovery Center 2006b).

B.6.5 Other Upgrading Processes

Hydrocracking is an upgrading process that cracks the bitumen in the presence of hydrogen and produces higher liquid yields than coking (up to 104 bbl of synthetic fuel per 100 bbl of raw bitumen) because of the uptake of hydrogen. Products from hydrocracking have lower contents of sulfur- and nitrogen-containing compounds than products from coking. Despite the need to consume hydrogen and operate at high pressures, hydrocracking has been chosen for use in two projects in Canada (Meyer 1995; Speight 1997).

In partial coking, the froth from the hot water recovery process is distilled at atmospheric pressure, thereby removing water and minerals.

Flexicoking uses a gasifier to gasify excess solid coke with a mixture of gas and air. The product is a low-heating-value gas that can be used on-site. This process produces a heavy pitch rather than coke as a by-product by using steam stripping in a delayed coking process. The yield of liquids is also increased.

The Alberta Oil Sands Technology and Research Authority Taciuk Processor simultaneously extracts and upgrades the bitumen from oil sands to produce a distillate oil (Meyer 1995). Heat alone is used to separate bitumen from sand, crack it, and drive off the hydrocarbons. Much of the heat for the process is obtained from the separated sand, which contains residual coke. The sand-coke is burned, and the heated sand is used to preheat unprocessed oil sands and then discarded. The Taciuk process has several advantages over the combination recovery-upgrading procedure described above. These include increased product yield, a simplified process flow, reduction of bitumen losses to tailings, elimination of the need for tailings ponds, improvement in energy efficiency compared with the hot water extraction process, and elimination of requirements for chemical and other additives.

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ATTACHMENT B1:

ANTICIPATED REFINERY MARKET RESPONSE TO FUTURE TAR SANDS PRODUCTION

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ATTACHMENT B1:

ANTICIPATED REFINERY MARKET RESPONSE TO FUTURE TAR SANDS PRODUCTION

1 INTRODUCTION

As noted in the discussion in Attachment A1 to Appendix A regarding refinery market response to future oil shale production, crude feedstocks, regardless of their provenance, all compete for acceptance into the U.S. refinery market based on a number of factors. These include value factors of the feedstock itself (i.e., critical chemical and physical parameters of the feedstock), reliability and consistency of supply, the logistics of transporting the feedstocks from points of recovery or generation to refining facilities, the extent to which existing refinery processing configurations align with feedstock parameters and their processing demands, and how efficiently those feedstocks can be converted to products currently in high demand. Collectively, all such factors contribute to a "refining margin" that is unique for every refinery and that is constantly changing on the basis of the availability of crude feedstocks as well as changing market demands for refinery products (e.g., distillate fuels, feedstock intermediates delivered to other refineries for further processing, and petrochemical feedstocks). While oil shale and tar sands are fundamentally different resources with respect to their depositional environments, their chemical compositions, their extraction and production technologies, and their marketable products, many of the same factors influencing penetration of oil shale–derived crude feedstocks into the refining market can be seen to be in effect for tar sands–derived feedstocks.

Attachment A1 of Appendix A of this PEIS gives an overview of the U.S. refinery market, including discussions of critical parameters in the crude oil refinery process, market responses to feedstock value parameters, refinery utilization factors, current refinery capacity, the Petroleum Administration for Defense District (PADD) system, current crude sources (including Canadian syncrude production), and other possible market drivers. This brief overview discusses how tar sands–derived crude feedstocks might be incorporated into the U.S. refinery market and how the availability of these new crude feedstocks may influence decisions regarding construction, expansion, or reconfiguration of processing capabilities.

In a manner very similar to the anticipated market development pathways for oil shale–derived crude feedstocks, the following factors predominate in supporting refinery market adjustments to tar sands–derived crude feedstock:

- The investment into and expansion of refining capacity are solely determined by the investor's long-term expectation of refining margins. Only those crude feedstock sources that can demonstrate long-term availability and consistent quality factors are likely to be considered as drivers for refinery processing capacity expansions or crude feedstock displacements.

- New crude feedstock sources displace sources in existing markets based on how well their quality parameters align with existing or expanding refining capability; the market will take proportionately longer to accept new sources with quality factors substantially different from existing or alternatively available sources; conversely, refineries will more readily consider an expansion in capacity within their current processing configurations if new feedstock sources become available and can be seen to result in satisfactory refining margins.

- Incremental expansion at existing facilities is the expected primary way in which tar sands–derived crude feedstock will be introduced into the refinery market. Given the modest ultimate production levels forecasted both collectively and at individual facilities, there will be little to no impetus to build new refineries solely in response to this U.S. tar sands–derived feedstock's newly established availability.

- Only high-volume feedstock streams of proven reliability and consistency will precipitate major refinery expansions and/or displacements, or major expansions and/or construction of long-distance pipelines to link the feedstock to distant refineries.

- Pipelines do not drive refinery market investments. Pipeline operators react to emerging markets and provide transportation linkage between the source and refiner.

- Intuitively, domestic sources of crude feedstocks are more desirable than foreign sources simply because of their inherently more secure status. However, to retain their advantage, such domestic sources must also compare favorably with imported feedstocks with respect to overall product yield and other quality parameters (e.g., contaminant and acid content).

2 IMPORTANT CHARACTERISTICS OF TAR SANDS RESOURCES AND RESULTING MARKETABLE PRODUCTS

Production of crude feedstock and/or asphalt from many facilities producing from tar sands deposits in Utah may approach a total of about 300,000 bbl/day over the next 20 years (2007–2027).[1] It is anticipated that most of the tar sands–derived feedstocks will be crude feedstock, with a smaller portion being produced as asphalt. Table 1 provides a comparison of some critical chemical and physical parameters of various tar sands deposits within selected Special Tar Sand Areas (STSAs) in Utah.

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1 To facilitate discussion of potential effects of tar sands development, the BLM assumed a commercial production level of approximately 300,000 bbl/day.

TABLE 1 Critical Chemical and Physical Properties of Selected Tar Sands Deposits

PROPERTIES OF SELECT UTAH TAR-SAND BITUMENS

PROPERTY	Tar Sand Triangle	P.R. Spring Rainbow I	P.R. Spring Rainbow II	P.R. Spring South	Sunnyside	Whiterocks	Asphalt Ridge
Bitumen content, wt%	4.5	14.1	8.5	6.5	8.5	8	10.9
Specific gravity	1.01	1.0157	0.9872	1.0083	1.0328	0.9979	0.97
Gravity, °API	8.6	7.8	11.8	8.8	5.5	10.3	14.4
Conradson carbon, wt%	16.7	14	17.4	24	14.8	13	ND
Ash, wt%	0.2	3.3	1.4	1.9	2.4	0.8	0.04
Pour point, °F	94	210	320	320	ND	ND	ND
Viscosity, cps	42638	8269	2900	7031	7373	29245	2015
Simulated distillation							
IBP, °F	316	279	316	308	ND	307	ND
Volatility, wt%	34.4	39.9	22.8	14.3	32.4	22.1	ND
IBP-400 °F, wt5	0.7	1.3	0.5	0.7	0.9	0.9	ND
400-650 °F	7.6	5.1	2.2	1.3	7.3	3.3	ND
650-1000 °F	26.2	25.6	20.1	12.3	24	18.8	ND
>1000 °F residue, wt%	65.61	68.1	77.2	85.1	67.6	77.9	ND
Elemental Analysis							
C, wt%	84.3	84.7	81.41	81.7	83.3	85	85.2
H, wt%	10.3	11.2	10.3	9.3	10.8	11.4	11.7
N, wt%	0.4	1.3	1.4	1.4	0.7	1.3	1
S, wt%	4	0.5	0.4	0.4	0.6	0.4	0.6
O, wt%	1	1.8	6.3	7.2	4.4	1.6	1.1
Atomic H/C ratio	1.47	1.6	1.51	1.36	1.56	1.61	1.65
M_r, g/mol	571	702	1381	1561	1024	ND	668
Gradient elution chromatography							
Saturates, wt%	13.3	9.5	15.8	4.1	13.2	15.3	10
MNA/DNA oils, wt%	9.7	10.2	3.5	5.3	21	8.5	11.4
PNA oils, wt%	11.7	11.4	9	0.9	5.9	11.9	4.4
Soft resins, wt%	25.9	13.9	5.8	4	13.9	16.7	18.4
Hard resins, wt%	1.9	1.1	2.3	1.8	5.6	2.6	1.2
Polar resins, wt%	3.5	2	3.6	1.1	1.7	2.7	3.7
Asphaltenes, wt%	30.6	31.3	35.9	55.7	29.8	31.2	39.9
Non-eluted asphaltenes, wt%	3.5	20.6	24.1	27.1	8.9	11.1	11.1

Source: On-line poster by Steve Schamel and John Baza

Source: Gwynn (2006).

Although it can be anticipated that development of each of the STSA deposits will follow very different cost and logistical schedules to generate marketable product, the refining market is generally insensitive to resource development costs and logistical demands and impediments. Therefore, for the purposes of this analysis, all tar sands developers are considered to be in the same starting position with respect to finding markets for their products, irrespective of the overall costs each developer has incurred in getting to that point.

Although the cost of resource development is outside the scope of determining the competitiveness of the resulting products to the refinery market, critical chemical and physical parameters of those products are not. Thus, for example, the Sunnyside deposit that would

produce raw bitumen with an American Petroleum Institute (API) gravity[2] of 5.5° puts the developer at a distinct disadvantage compared with developers of other deposits whose raw bitumen API gravities are higher, since the Sunnyside developer would need to invest greater effort to improve the gravity of his product for economical pipeline transport. However, as can be seen from Table 1, API gravities for any U.S. tar sands bitumen can range from a low of 5.5° to a high of 14.4°. Consequently, even the bitumen with the highest API gravity is still not acceptable for pipeline transport, suggesting that all developers would be faced with the requirement to improve on the quality of the raw bitumen they recovered before having any realistic opportunity of finding both a refining market and an economical way of getting their product to that market.

Likewise, developers whose raw bitumen has the lowest percentages of refining catalysts-fouling contaminants, such as sulfur and nitrogen, would have an initial competitive edge over sources where the amounts of these contaminants are higher. In addition to threatening the safe operation of refinery processing units, adding to the cost of operation by reducing the life of expensive catalysts and adding to processing unit downtime for catalyst replacement, the presence of both nitrogen and sulfur contaminants may cause a refinery to incur heavier regulatory burdens. Severe limitations could be placed on resulting processing emissions, which would require significant investments in pollution control devices before necessary operating permits could be secured. Even without emission limitations, the recently promulgated standards for low-sulfur diesel fuels for on-road vehicles further increases the costs of processing by requiring additional expensive sulfur removal steps to meet product specifications. Premature catalyst replacements, increased regulatory controls, and more rigorous product specifications can each severely impact refining margins and thus reduce the attractiveness of the feedstock. To remain competitive with intrinsically higher quality feedstocks, purveyors of high-sulfur, high-nitrogen, and low API gravity feedstocks must consider discounting or, alternatively, carrying the costs themselves of improving these parameters before offering their product to refineries.

Crude feedstock quality is among the most critical of factors affecting refinery market penetration. Because there has been very little commercial development of U.S. tar sands deposits, there is virtually no empirical evidence on which to base any presumptions of the quality factors for U.S. tar sands–derived products; however, irrespective of the recovery technology employed, recovery of bitumen from its natural setting is simply a physical separation process and is not expected to substantially change its chemical composition. Consequently, it is safe to assume that the quality factors displayed by bitumen in its natural setting will survive virtually unchanged throughout any separation processes (see Table 1).

Tar sands deposits in Canada are fundamentally different from tar sands in the United States. The presence of a free water sheath surrounding the inorganic sand and separating it from the bitumen in Canadian deposits (known as "water-wet tar sand") facilitates the separation of the bitumen from the sand using relatively inexpensive and highly effective (but water-intensive) separation technologies. Those same technologies, while technically

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2 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.

available to developers of U.S. tar sands, will not produce the same efficiencies of separation as they do for Canadian developers and would be executed at a higher cost in U.S. development or not at all because of the unavailability of the required volumes of water. Amended technologies to those practiced in Canada, as well as alternative technologies, are nonetheless available for U.S. tar sands, although at higher overall costs and/or reduced recovery efficiencies. As noted above, however, such development costs are not of particular concern to refiners; decisions regarding acceptance of new feedstocks are based on the quality, availability, and cost of the feedstocks and the refining margins of the resulting products, and disregard the difficulty or efficiency of resource recovery. In this sense, raw bitumen recovered from U.S. deposits can be expected to be generally equivalent to Canadian bitumen in critical quality factors, despite expected higher recovery costs. Likewise, synthetic crude resulting from upgrading of U.S. tar sands–derived bitumen is expected to be generally equivalent to synthetic crude that results from upgrading Canadian-derived bitumen to an equivalent extent, again, costs notwithstanding. Consequently, those same refineries that now are configured to receive significant quantities of Canadian syncrude or raw bitumen can be expected to find U.S. tar sands–derived feedstocks equally attractive from a quality perspective. Other factors of attractiveness, such as reliability and consistency of supply over time, have not been established for U.S. tar sands–derived feedstocks, however, and are not likely to be equivalent to Canadian analogs, based on the relative magnitudes, accessibility, and quality of the respective tar sands resources and the maturity of the Canadian tar sands industry and its supporting transportation infrastructures.

3 ISSUES ASSOCIATED WITH UPGRADING

As discussed above, all tar sands deposits are not equal with respect to the products they might potentially offer to refineries. Obtaining equality by improving upon or eliminating unattractive chemical and physical properties of the raw bitumen involves upgrading of the raw bitumen by either removing carbon (coking reactions) or adding hydrogen (hydrogenation) Reacting bitumen with hydrogen results in two distinct types of reactions: hydrocracking (adding hydrogen to complex, unsaturated molecules to make smaller, more desirable saturated hydrocarbons) and hydrotreating (converting sulfur- and nitrogen-bearing constituents to hydrogen sulfide and ammonia, respectively, both of which can be subsequently easily removed from the product stream). Upgrading can be performed to whatever extent is desired, yielding ever-increasing quality of resulting products with proportionally increasing costs. Upgraded products are generally referred to as synthetic crude, regardless of the extent of upgrading. Even modest degrees of upgrading would require a substantial investment in resources (e.g., electric power, natural gas, and water), expensive reactants such as hydrogen, processing equipment, and related infrastructure. Developers of tar sands deposits that exist in relatively remote, arid areas with limited access to required resources and other logistical constraints would be at a disadvantage in pursuing this strategy. Consequently, any upgrading performed at the tar sands development site would be expensive and impossible without significant investment in supporting infrastructures. Nonetheless, the analyses in this PEIS anticipate that some modest amount of upgrading of raw bitumen would occur at U.S. tar sands developments.

An additional strategic option exists that is unique to tar sands. The raw bitumen itself is a legitimate constituent of conventional crude oil and, without further chemical alteration, can serve as a feedstock for properly configured refineries. Some logistical impediments still exist for this development path, however. The relatively low API gravity of raw bitumen (see Table 1) preempts its transport by pipeline. However, diluents such as raw naphtha, raw gas oil, or other crude oil distillation condensates, any of which would be in abundance in integrated refineries, can be shipped to the tar sands development and mixed with the raw bitumen to form a solution (known in the industry as "dil-bit" or "dilbit") that can be transported by conventional pipeline. Once arriving at the refinery, the diluent can be separated and used again for pipelining subsequent batches of raw bitumen. However, dilution ratios as high as 30% by volume diluent may be necessary (Brierley et al. 2006), and transporting the diluent to the mine site in requisite volumes by truck would ensure that any strategy involving dilbit would be expensive. Nevertheless, as will be discussed later, evolution in processing capabilities in the refining industry to add greater coking capacity is compatible with this strategic option, and production and shipment of diluted bitumen are already being pursued by many Canadian tar sands developers. Of the more than 2.17 million bbl/day of crude feedstocks imported into the United States from Canada, approximately 400,000 bbl/day consists of un-upgraded bitumen (transported as dilbit), sold primarily to refineries configured to process heavy crudes.[3] Finally, a smaller fraction of Canadian crude imports is transported as "Syn-dil-bit," a blend of synthetic crude, distillation condensates, and bitumen. Such mixtures, however, are typically sold to refineries configured to process light to medium crudes. Each of the bitumen mixtures described above commands its own unique processing scheme, and major challenges remain for refiners of such bitumen mixtures. Bitumen dilutions typically are assembled to meet a target API gravity of 20°; however, most will still contain significant volumes of residuum and have a high sulfur content. By comparison, the synthetic crudes resulting from upgrading of raw bitumens would be characterized by virtually no residual and relatively low sulfur content.[4] Distillates yielded in their subsequent refining, however, would have high aromatic character, which would necessitate greater degrees of subsequent hydrotreating to produce rigorously specified transportation fuels. Further, distillate suites also would typically include relatively high volumes of polyaromatic gas oil, which would reduce the yields in subsequent downstream fluid catalytic cracking (FCC) units.

4 EVOLVING CRUDE FEEDSTOCK MARKETS

Currently, light crude (API gravity of 34° or higher) represents approximately 50% of the crude oil available on the world market. Much of the availability and thus more rapid depletion of light crudes are due to the Organization of Petroleum Exporting Countries (OPEC) quota system. This quota on total production volumes provides incentives to OPEC producers to sell

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3 To facilitate import of bitumen, pipelines specifically designed to deliver diluent to Canadian tar sands mine sites are also now being constructed.

4 Although synthetic crudes are typically low in overall sulfur content, the specific sulfur-bearing species that remain are difficult to treat. Significant effort is required to hydrotreat synthetic crude distillate fractions to meet the recently promulgated ultra-low-sulfur on-road diesel fuel specifications.

the higher margin light crudes. Production of light sour crude is expected to increase by 9 million bbl/day by 2015, but the production of light sweet crude is expected to increase by only 1 to 2 million bbl/day over the same period (Phillips et al. 2003). Availability of light sweet crude is expected to continue to decline as production in key areas declines. At the same time, availability of heavier synthetics and bitumen blends is increasing and is expected to reach almost 3 million bbl/day by the year 2015 (Brierley et al. 2006). Concurrently, demand for lighter distillate fuels continues to increase, and specifications for such fuels become more rigorous. Consequently, refiners throughout the country are focusing their attention on expanding their capacity for "bottom of the barrel" processing and seeking out heavier crude feedstocks, including synthetics. Traditionally, heavier crude feedstocks were converted to low-value fuel oils, asphalts, and lube stocks, with these relatively low-value products commanding severe discounting of the parent feedstock. However, reconfiguration to add coking, delayed coking, FCC, and hydrocracking capacities allows refineries to switch to heavier crude stocks and still meet market demands for lighter, more rigorously specified fuels.[5] Deep discounting of heavier crudes allows refineries to obtain amortization of their reconfiguration costs over a reasonable period while still maintaining adequate refining margins. Increased "bottom of the barrel" processing capacity is driven not only by "upstream" factors, such as crude source availability, but also by "downstream" factors such as increased markets for transportation fuels with a coincident decline in the market for heavier residuals, an increasing demand for anode-grade coke,[6] and a continued inclination by the refinery industry to meet changing processing and product demands by reconfiguring or expanding capacities at existing refineries rather than building new grass-roots crude processing capacity.

Crude feedstocks from Canadian tar sands production can be seen as significant competition for U.S. tar sands–derived synthetics and bitumen. Not only is the Canadian tar sands resource substantially larger, more contiguous, and more homogeneous than the U.S. resource, the Canadian tar sands industry is mature, and the volumes of Canadian imports are expected to grow significantly in the near term. For example, by 2015, a forecasted Canadian syncrude import volume of approximately 4.5 million bbl/day could represent as much as 28% of the U.S. refinery industry's crude consumption nationwide.[7]

Canadian imports into PADD 4 refiners, the region in which the Utah tar sands deposits are located, has increased from 2000 to 2005 by approximately 40%, as shown in Table 2.

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5 Phillips et al. (2003) reports that approximately 50% of the worldwide coking capacity is concentrated in the United States and totaled more than 2,000,000 bbl/day of installed capacity in 2003. In the 15 years previous to 2003, delayed coking capacity had grown by 56% in the United States, followed by hydrocracking (37%) and FCC (14%).

6 Anode grade coke is used in aluminum smelting and generally requires a crude feedstock that is low in sulfur and low in metals but that typically commands a high price, guaranteeing high refining margins even with the purchase of more expensive crude.

7 The Energy Information Administration (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 bbl per stream day refinery distillation capacity, which can be reasonably expected to come from incremental expansions of existing facilities. EIA crude volume consumption forecasts can be downloaded from http://www.eia.doe.gov/oiaf/aeo/pdf/aeotab_11.pdf.

TABLE 2 PADD 4 Crude Imports by Mode of Transportation

Mode of Transportation	Year (1,000s of bbl/day)					
	2000	2001	2002	2003	2004	2005
Total	505	501	522	527	555	559
Pipeline	474	468	488	489	510	508
Domestic	287	263	257	253	248	247
Canadian	187	205	230	236	261	260
Trucks	31	33	34	38	45	52
Domestic	31	33	34	38	45	52
Canadian	0	50	0	0	0	0

Source: EIA (2006a).

The majority of this was upgraded synthetic crudes. These crudes (after upgrading) are being offered at prices roughly equivalent to domestic conventional crudes in the region. The attractiveness of the synthetic crudes over conventional domestic crudes is based on the lack of light ends, such as butane and propane, and the lack of the bottoms or residual. Both of these fractions are of less value than the "middle of the barrel" transportation fuel progenitors and sometimes even below the cost of the crude, thereby destroying overall value. In addition, the domestic crude in the area has a higher sulfur content, which requires additional capital investment and operating expense to meet low-sulfur fuel specifications.

The overall markets for residual fuel oils have diminished over time. The key remaining market is heavy, relatively high-sulfur "bunker fuels" used primarily in ocean-going vessels. PADD 4 refineries do not have ready access to this market, primarily because of their geographic location. Therefore, there has been an incentive to import upgraded synthetic crudes, which lack a residual cut. Aside from acquiring a synthetically derived crude, which lacks a bottoms or residual product, it must either be sold as lower value asphalts and fuel oils or be upgraded into transportation fuels. The most common process technologies in the upgrading of bottoms (as found in bitumen, but not in upgraded synthetic crudes) are forms of thermal cracking called cokers. They produce roughly 65% transportation fuels and 35% petroleum coke from the residual portion of a full crude barrel. PADD 4 thermal cracking capacity has been relatively flat since 2001 (except for normal capacity creep through normal maintenance and debottlenecking) as shown in Table 3. This represents coking capacity at only 4 of the 16 PADD 4 refineries. This leaves a significant portion of the market with available options to invest in this heavy upgrading utilizing this new crude resource. Currently, two coker projects are under construction in PADD 4, with one more announced. In addition, there is one coker being constructed adjacent to, but outside PADD 4, at Borger, Texas, which is to be supplied as part of a new strategic partnership between Encana and ConocoPhillips.

Because of the Canadian tar sands industry's maturity and other important circumstantial factors such as resource availability, many Canadian developers have begun extensively

TABLE 3 PADD 4 Thermal Cracking Downstream Refining Capacity

	Year (1,000s of bbl/stream day)					
Coking Type	2001	2002	2003	2004	2005	2006
Total	45,700	45,700	46,850	47,250	47,950	48,850
Delayed	36,800	36,800	37,950	37,950	37,950	38,450
Fluid	8,900	8,900	8,900	9,300	10,000	10,400

Source: EIA (2006b).

upgrading their products to eliminate problematic characteristics of earlier products and enhance more desirable characteristics without proportional increases in costs. For example, Brierley et al. (2006) report that Suncor markets a light sweet crude, Suncor Oil Sands Blends A (OSA), that is the product of hydrotreating the products of delayed coking performed at the Suncor mine site. Suncrude Canada Ltd. markets a fully hydrogenated blend, Syncrude Sweet Blend (SSB), utilizing fluidized bed coking technology. Husky Oil now operates a heavy crude upgrading system consisting of a combination of ebullated-bed hydroprocessing and delayed coking to produce Husky Sweet Blend (HSB). The Athabasca Oil Sands Project uses ebullated bed hydroprocessing to produce Premium Albian Synthetic (PAS). Upgraded Canadian synthetics display very favorable characteristics over un-upgraded bitumens, with API gravities as high as 38.6° and sulfur contents as low as 0.1% by weight (Brierley et al. 2006). Light sweet synthetic crudes produced at mine site upgrading facilities command a premium price on the market (but still discounted relative to conventional light sweet crudes) and are comparable to conventional light sweet crudes in many respects. However, because of the high aromatic character of the parent bitumen, even these upgraded light sweet synthetic crudes are attractive only to refineries configured specifically to handle them.

In recent years, strategic mine site upgrading decisions have not been made unilaterally by Canadian developers, but, instead, are the products of extensive collaboration with individual refineries. The result has been the production of synthetic feedstocks uniquely suited to a particular refinery's processing capabilities and, at the same time, reconfiguration strategies undertaken by the refineries to ensure full compatibility with particular synthetic crude sources. The highly integrated agreements between feedstock supplier and refiner that result from such collaborations are not easily overturned or displaced. However, while such one-on-one collaborations can yield both increased overall efficiencies and maximum refining yields, it is generally acknowledged that, as the Canadian tar sands industry continues to grow, there will be an increasing need to direct synthetic crude production into a few "marker" categories in consultation with major refining market centers as opposed to individual refineries, rather than allow a continuing expansion in the number of "boutique feedstocks" (OSEW/SPP 2006).

Irrespective of any controls being placed on the variety of synthetic crudes being developed, it will continue to be the case that Canadian tar sands developers will have much greater opportunities to undertake bitumen upgrading at their mine sites than will

U.S. developers. The ability to upgrade at the mine site, together with purchasing agreements already in place for synthetic crudes with specific properties, gives a distinct advantage to Canadian developers over their U.S. counterparts in the competition for refinery market share, especially in the near term.

Notwithstanding the extensive mine site upgrading discussed previously, the potential refinery market for raw bitumen would be only incrementally different from the market available to producers of relatively heavy conventional or synthetic crudes, including synthetic crudes from tar sands. Refineries configured to accept heavier crude feedstocks, including Canadian synthetics upgraded to various degrees, would be in an ideal position with respect to processing capability to accept the raw bitumen. However, processing schemes are established against the characteristics of a particular crude feedstock or feedstock blend, and myriad process modifications are required before even modest changes in feedstock character are made. Thus, simple replacements of feedstocks are not necessarily straightforward operations even if the required processing units are in place. In addition to the unique processing requirements of each feedstock, available processing capacity for new sources is likely to be very limited. This is especially the case for refineries that have recently reconfigured to accept products from Canadian sources that currently import both synthetic crude and dil-bit into the United States as heavy crude feedstocks. All of the above being said, it is the case that PADD 4 refineries in closest proximity to the STSAs were some of the first U.S. refineries to reconfigure to accept Canadian synthetic crude. Refineries in Denver, Salt Lake City, and Cheyenne, among others, have reconfigured to accept Canadian feedstocks, including raw bitumens, and would be the most likely candidates for receipt of U.S. tar sands–derived crude feedstocks and/or raw bitumen.

The evolution of the refining industry toward heavier feedstocks bodes well for the tar sands industry in a general sense; however, there are still substantial supplies of conventional crude oils of equivalent densities and qualities against which unconventional or synthetic crudes such as those from tar sands must still compete. Those other conventional sources aside, however, of more immediate interest and concern to U.S. tar sands developers are the current and anticipated productions of Canadian tar sands–derived synthetic crudes, and especially the upgraded synthetic crudes that are now being offered.

5 CONCLUSIONS

Bitumen and synthetic crude oil derived from Canadian tar sands represent the most immediate and direct competition to U.S. tar sands–derived feedstocks for refinery market share. The enormous size of the Canadian tar sands resources, the maturity of the Canadian tar sands industry, the proven reliability and consistency of Canadian products, the ever expanding pipeline infrastructure devoted to delivering Canadian tar sands to U.S. refineries, and the ability of Canadian developers to undertake extensive upgrading of recovered bitumen at their mine sites to remove unfavorable characteristics all give Canadian developers substantial market advantages over U.S. developers.

Refineries in PADD 4 are geographically closest to each of the STSAs and have also already undertaken reconfiguration of their processing streams to accept heavy synthetic crude feedstocks, making them the most likely candidates to receive U.S. tar sands–derived feedstocks. However, Canadian imports of bitumen and synthetic crude are already being received at these refineries, and unused processing capacity is not expected to be available in any appreciable amount. It is possible that the current investment rate of transportation of Canadian crudes to alternative markets, such as the Gulf Coast (PADD 3), the West Coast (PADD 5), and international export to China and Asia could produce more competition for Canadian crudes over the long run and provide more economic room for tar sands–derived crude feedstock in PADD 4.

With a projected maximum collective production rate approaching a total of about only 300,000 bbl/day, the U.S. tar sands developments would not be large enough to single-handedly or collectively motivate significant expansions in either long-range crude pipeline transportation networks or refinery expansions, suggesting that penetration into the refinery market would be limited to refineries in the immediate vicinity of the STSAs, primarily the properly configured PADD 4 refineries. Only modest expansions of crude oil pipeline networks already in place in PADD 4 would be required to connect STSAs to PADD 4 refineries.

The market for PADD 4 refinery products is geographically constrained, thus even if additional processing capacity were to be made available by PADD 4 refinery expansions, construction and/or expansion of product pipelines to distant markets would need to occur before that additional processing capacity could be utilized.

6 REFERENCES

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

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