APPENDIX B

Depositional heterogeneity and fluid flow modeling of the oil shale interval of the upper Green River Formation, eastern Uinta Basin, Utah

Final Project Report
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Project Objectives

1. Conduct a detailed sedimentological analysis of about 100 logs and a 1000-foot core to help construct realistic reservoir characteristics of the main organic-rich zones of the Green River shale in Utah.
2. Create a stratigraphic map and depositional analysis of a 40 square kilometer area in the Uinta Basin.
3. Perform a detailed, bed-by-bed investigation of lithological variations of oil shale, including distinguishing rich vs. lean zones.
4. Understand the controls and environmental conditions that led to the deposition of oil-shale rich zones.
5. Conduct a quantitative assessment of the impact of reservoir heterogeneity on production by simulating production from a realistic stratigraphic section.
6. Provide oil production rates, oil recoveries, and residual oil values for a section (around the core) in the Uinta Basin.

Summary of Project Outcomes

In this project, a detailed geological analysis was performed followed by a reservoir modeling exercise. For the geological analysis, ~300 m of cores were correlated to gamma and density logs in well P4 in the lower to middle Eocene (49.5–48.0 million years ago (Ma)), upper Green River Formation of the eastern Uinta Basin, Uintah County, Utah. In well P4, three distinct facies associations were identified that represent three phases of deposition linked to the hydrologic evolution of Lake Uinta: 1) an overfilled, periodically holomictic lake system with deposition of primarily clastic mudstones, followed by 2) a balanced-filled, uniformly meromictic lake system with deposition of primarily calcareous and dolomitic mudstones, followed by 3) an underfilled, evaporative lake system with nahcolite precipitation. The richest oil shale zones were deposited during the second depositional phase. While the studied interval is popularly known as oil "shale", this bed-by-bed investigation revealed that lithologically, thus chemically, the interval is quite heterogeneous. This complexity has significant impact on modeling strategies for oil shale exploitation.

In the project’s second phase, various in-situ oil shale production methods for this heterogeneous resource were explored. In-situ methods have a lessened environmental impact and are likely to have lower costs than mining and surface processing. Heat transfer pathways, chemical kinetics, geomechanics, multiphase fluid flow, and process strategies add complexity to any in-situ oil shale production strategy. Understanding each of these phenomena as well as appropriate model coupling is necessary to accurately model in-situ oil shale production processes. Results from in-situ oil shale modeling with the STARS simulator show that oil production from the Green River Formation is feasible. Challenges to achieving economic rates of recovery include porosity-permeability creation and the establishment of contiguous pathways between injectors and producers. Idealized energy efficiency and carbon footprint for an electrical conduction-
type process were estimated as 3:1 net energy gain and 36 kg CO₂/barrel (bbl) oil produced respectively.

**Presentations and Papers**

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Geological Characterization

The Green River Formation in northeastern Utah, northwestern Colorado, and southwestern Wyoming (Figure 1) contains the world’s largest deposit of oil shale. Estimates of recoverable resources in Utah alone range as high as 321 billion barrels (1). A recent Utah Geological Survey (UGS) report uses five key constraints to estimate Utah’s potential recoverable oil shale resource at 77 billion barrels (2).

While the unconventional asset represented by the Green River Formation is obvious, sedimentology of its oil-shale bearing units is insufficiently documented, particularly in the subsurface. In outcrop, detailed investigation of oil shale lithology is hindered by weathering as evidenced by fine-grained mudstone laminations that are more clearly visible in slabbed core than in outcrop.

Previous work in the Green River Formation of the eastern Uinta Basin describes basin-margin depositional environments from outcrops, particularly for the lower and middle part of the formation (3, 4, 5), but lack information regarding subsurface lithological variation. Other work interpreting well log data without core data (6) describes the strata in this region in a scope that is temporally too broad for the objectives of this study.

This study focused on the upper Green River Formation closer to the basin center than previous work. It provides the first detailed account of subsurface sedimentology of the upper part of the Green River Formation in the eastern Uinta Basin. The study used a ~300 m thick core correlated to gamma-ray and neutron density logs to meet its objectives.

Regional Geology

As the Late Cretaceous Sevier fold-and-thrust orogeny waned during the late Campanian to early Maastrichtian, the onset of Laramide orogeny broke the broad foreland basin of the Western
Interior Seaway into a series of perimeter, axial, and ponded basins (7,8). The Uinta Basin formed as a ponded basin bounded to the west by the Sevier orogenic belt; to the south by the San Rafael, Uncompaghre, and Monument uplifts; to the east by the Douglas Creek arch; and to the north by the Uinta uplift (Figure 1). The north-south trending Douglas Creek arch separated the Uinta Basin from its time-equivalent neighbor, the Piceance Creek Basin in northwestern Colorado, and acted episodically as a hydrological barrier and as a subsumed structural saddle through the duration of deposition in these basins. The Piceance Creek Basin was, in turn, subjected to inundation from the overfilled Greater Green River Basin in southwestern Wyoming (Figure 1).

![Figure 1. Location map of the study region in the western United States showing the configuration of the Laramide lacustrine basins in which the Green River Formation was deposited in the early to middle Eocene (49.5–48.0 Ma).](image)

The Green River Formation in the Uinta, Piceance Creek, and Greater Green River Basins was deposited in the early to middle Eocene, approximately 55 Ma to 44 Ma (9,10). Ash beds from volcanism in the Absaroka Mountains episodically blanketed the region, providing datable
isochrons (9). Typical of ponded basins, the Uinta, Piceance Creek, and Greater Green River Basins were at times internally drained, depositing several thousand meters of profundal-lacustrine and evaporative strata in addition to fluvial-lacustrine, paludal, and alluvial strata (7).

**Study Area and Local Geology**

This study focuses on the oil-shale bearing profundal-lacustrine and evaporative strata of the Green River Formation in the eastern Uinta Basin of Uintah County, located in northeastern Utah (Figure 2). The highest quality core with available correlating well logs is from well P4 (also known as U059) and is housed at the UGS Core Research Center in Salt Lake City, Utah. Core P4, located in T10S-R25E, Uintah County, was recovered from the 65 m (211 feet) to 357 m (1170 feet) depth zone, covering 292 m (959 feet) of thickness.

The present study follows marker-bed nomenclature of Remy (5) due to the prominence of these marker beds in core P4 and the precedent they set for subsequent literature (9). This nomenclature was defined in outcrops of fluvial-lacustrine and marginal lacustrine strata of Nine Mile Canyon in the south-central Uinta Basin (Figure 2). Variations on Green River Formation nomenclature in the literature and the stratigraphic position of core P4 in that system are summarized in Figure 3. In addition, this study follows the oil shale nomenclature of Vanden Berg (2), a system consisting of rich (R) and lean (L) oil-shale zones derived from Uinta Basin well log data. The richest zone, the Mahogany Zone, is found in zone R7 (2). A-Groove and B-Groove are the names for the kerogen lean zones of L7 and L6 respectively (Figure 3). These zones are identified in density logs with the Fischer Assay, which correlates the presence of kerogen in the deposits with decreased bulk density (2). Oil shale zone richness varies; yield estimates for rich zones range from 15 to 50 gallons per ton (GPT) (2).
Figure 2. Location of well P4 (also known as well U059) in the eastern Uinta Basin of Uintah County, northeastern Utah. Note the location of Nine Mile Canyon, which is the site of previous outcrop-based work on the Green River Formation.
Figure 3. Stratigraphic nomenclature of Green River Formation in and around the study area. Core P4 belongs to the upper Green River Formation.

**Methods**

Lithology, sedimentary structures, and trace fossils (burrows) of core P4 were logged through visual investigation; HCl and a light microscope were used when necessary. Bioturbation intensity in the cores was quantified using a six-grade scale (6 being the highest) to generate a bioturbation index (BI) log (11). Photographs of key features were taken at various core depths.
Scanned images of Gamma and density well logs of P4 were acquired from UGS and digitized using NeuraLog software. The digitized logs were uploaded in Landmark’s Geographix software to pick stratigraphic surfaces correlated to core P4. These surfaces, defined as gamma kicks, are regions where gradual fluctuations in gamma values lead to, or are followed by, sudden changes in gamma values.

**Results**

*Core Sedimentology*

Figure 4 shows the graphic lithological log of core P4. The six lithofacies identified can be grouped into three broad intervals. The interval lying below the base of the Mahogany Zone (>235 m depth) is characterized by the preponderance of clastic mudstone facies. The middle portion of the core (125-235 m depth) is dominated by calcareous mudstone facies. The upper portion of the core (< 125 m depth) is characterized by evaporites. Oil shale, not categorized here as facies, is unevenly distributed among the three intervals.
Figure 4. Geophysical, chemical, ichnological, and lithological logs for well P4 (see Figure 2 for location). Prominent marker beds, rich (R) and lean (L) oil-shale zones, and genetic stratigraphic horizons (GRFm#) are labeled.
Sandstones are also unevenly distributed throughout the core as thin beds, but two groups of thicker sandstones are found. One unnamed group lies near the base of the core. Another group, identified as the Horse Bench sandstone (5), lies near the top of the core (Figure 4).

Two main groups of tuffs are identified. The lower tuff at the base of the Mahogany Zone is the Curly Tuff. The upper tuff, approximately 18 m above the top of the Mahogany Zone, is the Wavy Tuff (5, 9).

Evaporites, identified only in the form of nahcolite, are found only above the Mahogany Zone. With the exception of current- and wave-ripples in the Horse Bench sandstone, nearly all sedimentary structures indicating lake bottom agitation appear below the Mahogany Zone.

The sedimentological description and interpretation of the oil shale and of the six lithofacies are as follows:

1. Oil Shale
   a. Description: The term oil shale is lithologically ambiguous and scientifically misleading. Hence, oil shale is not identified as a facies in this study. Lithologically, oil shale in core P4 consists of kerogen-rich intervals of calcareous and dolomitic mudstones. The kerogen richness required for a mudstone to be considered as oil shale is an economic question, not a sedimentological one. Oil shale richness is represented in the Fischer Assay log of Figure 4 by oil yield in GPT. This log shows the distribution of average rich versus lean oil shale zones throughout core P4. The Mahogany Bed of the Mahogany Zone yields up to 75 GPT in the vicinity of core P4. Kerogen-rich oil shale does not react as strongly with HCl as the kerogen-poor calcareous and dolomitic mudstones due to its higher kerogen to carbonate ratio. Oil shale appears distinctively dark brown to black and is finely laminated (<1 mm thick) in core P4 (Figures 5a, 5b, and 5c). Rich oil shale beds with yields greater than 20 GPT are rarely thicker than 30 cm. Oil shale is often friable with core samples tending to crack along oil-shale lamination planes.
   b. Interpretation: Interpretation of oil shale is discussed in the interpretation section of calcareous mudstones (Facies 2).
Figure 5. A) Black, organic-rich, and friable oil shale (328.88 m depth in litholog of Figure 4). B) Mahogany Bed, the richest oil shale bed in the Mahogany Zone, which is the richest oil shale zone in Green River Formation (219.46 m depth in Figure 4). Core base is bottom-right and top is upper-left. C) Details of the Mahogany Bed. Lighter interlaminations are kerogen-poor calcareous and dolomitic mudstones (218.54 m depth in Figure 4). Note that scale is 5 cm long in all photos.

2. Facies 1: Clastic mudstones
   a. Description: The clastic mudstone facies consists of clay-rich to sometimes silty, grayish-beige to dark brown, finely-laminated (<1 mm thick) mudstones (Figure 6a). Light brown, beige, and gray laminations can be similar in color to calcareous or dolomitic mudstone facies (Facies 2 and 3, respectively), but the clastic mudstone facies never fizzes under HCl. The facies is often interrupted by ripple-topped interbeds of siltstone or sandstone lenses (<2 cm thick). Additionally, it shows varying degrees of soft-sediment deformation (Figure 6b); deformation due to post-depositional mineral and nodular growth of pyrite, siderite, and possibly marcasite; deformation due to overburden strata; and deformation due to bioturbation (Figure 6c). Despite local deformations and interruptions by sand lenses, the clastic mudstone facies is most commonly horizontally laminated.
b. Interpretation: The horizontally-laminated, non-calcareous, non-dolomitic, and very fine-grained nature of the clastic mudstone facies strongly suggests the deposition of siliciclastics in the deeper part of the lake basin, likely below storm wave base. Ripple-topped interbeds of coarser materials, especially those with scoured bases and basal rip-up clasts, indicate event depositions when turbidity currents reached this distal depositional site.
3. Facies 2: Calcareous mudstones
   a. Description: The calcareous mudstone facies consists of microcrystalline, calcium carbonate-rich, yellow-beige to dark brown, finely laminated mudstones (<1 mm to 1 mm thick laminae) and reacts strongly to HCl. The richest oil shale zones are dominated by calcareous mudstone facies (Figures 7a and 7b).

Figure 7. A) Typical calcareous-mudstone-dominated rich oil shale (259.69 –255.12 m depth in Figure 4). Lighter rocks on either end of figure are dolomitic mudstones. Gray laminated rocks are kerogen-poor vs. kerogen-rich interlaminations of calcareous mudstones. Black rocks at the middle portion are calcareous mudstones highly rich in kerogen. Each core box is ~1 m long. Core base is bottom-right and top is upper-left. B) Details of calcareous mudstone facies. Light-colored granular beds are unnamed tuffs (193.24 m depth in Figure 4). C) Bioturbated calcareous mudstones at the base of photograph, overlain by sandstone and by kerogen-rich calcareous mudstones (332.54 m depth in Figure 4). Note that scale is 5 cm long in all photos.
The calcareous mudstone facies shows evidence of local soft-sediment deformation but rarely of ripple cross-lamination or ripple-topped interbeds as does the clastic mudstone facies. Calcareous mudstone facies that is finely interlaminated with darker mudstones is difficult to distinguish from the clastic mudstone facies. However, the calcareous mudstone facies will always react with HCl while the clastic mudstone facies will not. Evidence of bioturbation is more commonly found in the calcareous mudstone facies than in other facies, although bioturbation is absent in the calcareous mudstone facies above the Mahogany Zone (Figure 7c).

b. Interpretation: Since there is no evidence of the production of calcareous shells, organic encrustations, or skeletal elements and evidence for clastic allochthonous calcium input or post-depositional precipitation is lacking, the remaining possible source for calcium in the calcareous mudstone facies is from direct precipitation from the water column (12). The association of carbonate minerals with oil shales is well documented (13) and is often characteristic of deep lacustrine basins (14).

The conditions for the deposition of the calcareous mudstone facies in association with the oil shale could be a meromictic, stratified lake with a slightly alkaline, nutrient-rich upper-layer and a high-pH, anoxic lower-layer. During seasonal algal blooms, removal of dissolved CO₂ from the water column through photosynthesis raised the upper-layer pH and allowed for the concentration of calcium and magnesium in algal sheaths. As algal blooms died, organic material was deposited in the lake bottom, where decomposition was inhibited by anoxic conditions. In this way, carbonate was deposited in association with the organic constituents of oil shale (15).

In order for the conditions to be met in which the calcareous mudstone facies were deposited rather than clastic mudstone facies, there must have been both meromictic lake conditions and some distance from the overwhelming input of clastic mudstone. Both of these conditions were met in deep water lake basins. The finely laminated nature of calcareous mudstone facies and lack of wave- or current-generated sedimentary structures further supports the interpretation of deposition of calcareous mudstone facies in deep water.

4. Facies 3: Dolomitic mudstones
a. Description: The dolomitic mudstone facies consists of microcrystalline, light beige to light gray dolomite (CaMg(CO₃)₂) mudstone that reacts weakly with HCl. This facies is sometimes finely laminated (<1 mm to 1 mm thick laminae; Figure 8a) but is often deformed and may bear nodular growths of pyrite, siderite, and possibly marcasite. The lower portion of the core exhibits a more even distribution of laminated dolomitic mudstone facies in association with the rich oil shale zones, calcareous mudstone facies, and clastic mudstone facies. Near the top of the core, the
dolomitic mudstone facies is closely associated with the evaporite facies (Facies 5). It is also massive rather than laminated, deformed, and pocked by nahcolite dissolution vugs (Figure 8b). Although the dolomitic mudstone facies is generally lighter in color, it can resemble either calcareous mudstone facies or clastic mudstone facies. However, the dolomitic mudstone facies reacts weakly with HCl while the calcareous mudstone facies exhibits a strong HCl reaction and the clastic mudstone facies exhibits no HCl reaction.

Figure 8. A) Finely laminated dolomitic mudstones (321.56 – 321.26 m depth in Figure 4). B) Massive dolomitic mudstones with nahcolite vugs (110.64 m depth in Figure 4). Note that scale is 5 cm long in all photos.

b. Interpretation: Dolomitic mudstone facies are interpreted differently for the lower and upper portions of the cores. In addition to calcium carbonate, magnesium-calcium carbonate is also found in association with oil shale (15). Certain algal blooms selectively remove magnesium from the water column for concentration in algal sheaths. The laminated dolomitic mudstone in the lower portion of the core (>235 m depth) probably formed under meromictic lake conditions similar to those that formed
the calcareous mudstone facies. Slight variations in ecological conditions may have regulated the deposition of calcareous versus dolomitic mudstones.

Primary inorganic dolomite precipitate is often deposited in shallow, saline lakes (16). The association of massive dolomitic mudstone facies with evaporites in the upper portion of the core (<125 m depth) is interpreted to indicate such conditions. The perceived problematic transition from deep water carbonates to shallow water evaporites without intervening basin-margin clastics is explained in the Discussion section.

5. Facies 4: Sandstones
   a. Description: The sandstone facies consists primarily of very fine, yellow-beige to gray sandstones. This facies contains rare instances of coarser-grained sandstones found in thin (1-3 cm) intervals. While most sandstone lenses are too thin to discern visible grading patterns, some thicker (>30 cm) sandstone beds show normal grading with erosive basal-contacts and rip-up mudstone clasts (Figure 9a). Asymmetrical and symmetrical ripple cross-laminations appear locally (Figure 9b). A prominent, medium-grained, well-rounded tar sandstone layer lies at 279 m depth. Most individual sandstone beds are thin (1-3 cm) and show no ripples or graded relationship to either overlying or underlying mudstones (Figure 9c). Thicker sandstone beds below the Mahogany Zone bear limited bioturbation (Figure 9d).
Figure 9. A) Sandstone facies (Horse Bench sandstone) with erosive basal contact and rip-up clasts (95.4 m depth in Figure 4). B) Wave ripple lamination (313.49 m depth in Figure 4). C) Sandstone bed (darker layer in the middle) with sharp lower and upper contacts, underlain by calcareous mudstones and overlain by clastic mudstones (278.89 m depth in Figure 4). D) Prominent solitary burrow in sandstone facies (278.59 m depth in Figure 4). Note that scale is 5 cm long in all photos.
In core P4, sandstones are mainly found at two stratigraphic intervals (Figure 4). The lower sandstone interval lies between ~300-315 m and the upper sandstone interval, identified as the Horse Bench sandstone (5), lies between ~80-95 m.

b. Interpretation: The deposition of sand facies in core P4 is interpreted to represent either 1) episodes of lower lake levels that brought the basin margin closer to the position of core P4, or 2) the periodic deposition of large turbidity flows capable of reaching the distal basin position of core P4. The sedimentary characteristics of the sandstone intervals indicate that most of these beds were not deposited from turbidity currents. Rather, the near absence of normal grading and the presence of oscillatory wave ripples suggest that these sandstone beds are related to periods of decreased distance between core P4 and the basin margin (i.e., decreased lake level). In the upper portion of the core, the deposition of the Horse Bench sandstone immediately following the deposition of both bedded evaporites and shallow, saline-water dolomitic mudstones suggests the onset of a wetter climate and fresher lake water conditions following a period of aridity and salinity.

6. Facies 5: Evaporite (nahcolite, NaHCO3)
   a. Description: The evaporite facies, found only above the Mahogany Zone, consists of the brown to gray, bedded precipitation of nahcolite (Figures 10a and 10b) as well as vugs filled with nahcolite (Figure 10c). No halite was observed. Nahcolite beds are generally < 3 cm thick and interbedded with calcareous mudstone facies. Beds containing nahcolite vugs can be >5 cm thick and are found mostly in massive, deformed dolomitic mudstones.

   Figure 10. A) Bedding plane view of bedded nahcolite (125.58 m depth in Figure 4). B) Small nahcolite vugs (113.45 m depth in Figure 4). C) Large nahcolite vugs (122.83 m depth in Figure 4). Note that scale is 5 cm long in all photos.

   b. Interpretation: The deposition of evaporites indicates conditions of shallow, saline water. Nahcolite can precipitate through shallow lake-bottom nucleation (bedded
nahcolite in core P4) or as displacive intrasediment nodules (vug-filling nahcolite in core P4) (17).

Nahcolite deposits in the Green River Formation are a significant economic resource and can serve to increase the value of otherwise costly surface or subsurface oil shale mining operations (18). However, their potential assistance or detriment to in-situ electrical, air, or steam heating production of oil from oil shale is yet to be determined.

In contrast to the eastern Uinta Basin, the strata of the Piceance Creek Basin show a higher prevalence of saline water facies, including extensive nahcolite deposits, below the Mahogany Zone (9). This difference is interpreted to represent varying hydrologic gradients at different times among the Eocene lake basins. These hydrologic gradients are further explained in the Discussion section.

7. Facies 6: Tuff (zeolite sands)
   a. Description: The tuff facies consist of both biotite ash and zeolite (hydrous aluminosilicate) sands, possibly including analcime (hydrated sodium aluminosilicate) in a matrix of unidentified fused volcaniclastic mineral hash. Two large (~75 cm thick) ash beds (Figure 4) are identified as the Curly Tuff (Figure 11a) and Wavy Tuff (Figure 11b). At least 17 other distinct, unnamed tuff beds are found in the core, with thicknesses ranging from 3–12 cm (Figure 11c). The tuff beds, together with adjacent underlying and overlying beds, are characteristically highly deformed.
b. Interpretation: As reported by Smith et al. (9), tuff ages are $49.02 \pm 0.30$ Ma for the Curly Tuff and $48.37 \pm 0.23$ Ma for the Wavy Tuff (ages are weighted means with errors of $2\sigma$). The Absorka volcanic province in northwest Wyoming and southwest Montana and the Challis volcanic field in Idaho were active at these ages and may be the source of both Curly and Wavy Tuffs (9). Zeolites represent volcanic glass altered after deposition in highly saline or alkaline waters (19), which supports the interpretation of high alkalinity lake conditions during the deposition of calcareous and dolomitic mudstones.

**Bioturbation**

Bioturbation occurs almost entirely in the lower portion of the core, particularly at intervals where beds of calcareous mudstone facies alternate with beds of clastic mudstone facies (Figure 4). It is likely that the trace-making organisms periodically colonized the lake bottom during aerobic bottom-water, holomictic conditions. These trace makers were able to mine lower tiers of sediments that were deposited during anaerobic bottom-water, meromictic conditions. When stratification in water-column resumed, anaerobic bottom-water conditions precluded
bioturbation. Such tiering of bioturbation is observed near the base of the core (325-350 m depth) in the BI log of core P4 (Figure 4). Tiered bioturbation controlled by bottom-water oxygen-level is well documented in the literature of marine ichnology (20).

Meromictic conditions were more prevalent farther up the core (>235 m depth) as evidenced by the onset and eventual dominance of thick intervals of calcareous mudstones. The upward-decreasing trend of clastic mudstones suggests greater distance of well P4 from the shoreline, possibly indicating greater water depth and better conditions for lake stratification. The halt of bioturbation and the increasing prevalence of calcareous mudstones above 235 m depth in core P4 further support the interpretation of deep, anoxic bottom-water conditions in the middle portion of core P4 (125-235 m depth).

*Gamma Log*

Eleven picks of potential genetic-stratigraphic (i.e., isochronous) surfaces were made in the upper Green River Formation from the gamma log of well P4. These eleven picks mark the top of stratigraphic units; names are abbreviated as GRFm followed by a three to four digit numeral. The stratigraphic order of GRFm picks as well as rich/lean oil shale zone picks in core P4 is shown in Figure 4. These eleven picks, coupled with six picks of rich and lean zones (2), are useful for ongoing subsurface stratigraphic correlation in the upper Green River Formation in the Uinta Basin.

The gamma log appears chaotic in the lower portion of the core, with at least two intervals of increasing-upward gamma values culminating at GRFm400 and GRFm500 (immediately below the Mahogany Zone). Above the Mahogany Zone, the gamma log shows a series of repetitive cycles of decreasing-upward gamma values with each cycle of decreasing gamma values topped by a sudden dramatic increase in gamma values. This pattern becomes less comprehensible above GRFm1000 (Figure 4).

When correlated to core sedimentology, many of the highest gamma values correspond to clastic mudstone facies (e.g., depth interval 244-250 m) while many of the lowest gamma values correspond to calcareous mudstone facies (e.g., most of the Mahogany Zone in depth interval 215-235 m). Therefore, the gamma log of core P4 can be considered as a direct measure of the relative abundance of clastic versus calcareous mudstones. This relationship, in turn, reflects the interplay of lake-level, water-depth, and lake stratification.

Two scenarios can be invoked to compare the relative abundance of clastic versus calcareous mudstones: 1) high gamma values correspond to clastic mudstones, indicating a wet climate favorable for delivering detrital-rich sediments (with K-feldspar, U, and Th) to the lake by surface runoff; low gamma values correspond to calcareous mudstones, indicating less detrital input during dry climate; or, preferably, 2) high gamma values correspond to clastic mudstones, indicating a fall in lake-level during which detrital input reaches the basin center (i.e. location of core P4); low gamma values correspond to calcareous mudstones, suggesting a rise in lake-level...
generating deeper, stratified water conditions with little to no input of siliciclastic fines at the basin center. Note that the second scenario is the inverse of gamma log interpretations of sand versus shale for marine and lacustrine environments (21).

Gamma signatures in the lower portion of the core (below the A-Groove) range from chaotic to bell-shaped (increasing-upward gamma). At least two bell-shaped trends, at GRFm400 and GRFm500, indicate a sudden richness of carbonate lithology (deep water facies) followed by a gradual increase in shale lithology (shallow water facies). Hence, these bell-shaped trends indicate shallowing-upward cycles, interpreted to be part of the lake system in which sediment and water supply exceeded (i.e., overfilled) or balanced (i.e., balanced-filled) with accommodation.

The gamma curve in the upper portion of the core, above the Mahogany Zone, exhibits a sawtooth pattern; high gamma values decrease gradually upward and then increase suddenly. These patterns are clear in GRFm1000, 900, 850, and 700 (Figure 4). The characteristic pattern of the gamma log exhibits aggradational to deepening-upward cycles. The persistence of deep water (i.e. calcareous mudstones) facies through the upper portion of the core coupled with the gamma signature indicates that the basin was overall a deep, balanced-filled lake system.

**Discussion**

Sedimentology of core P4 is interpreted to represent a depositional environment distal from the basin margin and sediment-input sources. Sedimentary structures such as current and wave ripples that were formed within a storm or fair weather wave base are only observed in limited places (the Horse Bench sandstone and other thin, scattered sandstones). However, the distance of core P4 from the shoreline varied over time, as evidenced by the three facies associations found in the core.

Excluding the volcanic input of tuff, the six facies of core P4 can be divided into three facies associations: A) relatively shore-proximal facies association (235-358 m depth) including clastic mudstones, calcareous mudstones, laminated dolomitic mudstones, and sandstones; B) deep-basin facies association (125-235 m depth) including mostly calcareous mudstones with small amounts of clastic mudstones and sandstones; and C) shallow water and evaporite facies association (60-125 m depth) including mostly sandstones, massive dolomitic mudstones, nahcolite, and some calcareous mudstones. The richest oil shale deposits are found in association B.

The models of overfilled, balanced-filled, and under-filled lake basins (22) suggest that lake-basin type is a function of sediment, water supply, and accommodation due to basin subsidence. Under conditions of continuous basin subsidence, sediment input and water supply should decrease with time, changing basin systems from overfilled to balanced-filled to under-filled.
The distinctly different facies associations of core P4 (Figure 4) resulted from changes in the lake basin system. In the lower portion of the core (> 235 m depth, facies association A), the pairing of the decreasing-upward trend in the abundance of clastic mudstone and the increasing-upward trend in calcareous mudstone is interpreted to reflect deepening conditions at core P4 in the Uinta Basin. This deepening resulted from an overfilled lake condition (excess of water and sediment input relative to accommodation; see Figure 12a. The overfilled lake condition led to a balanced-filled condition (Figure 12b) as the Uinta and Piceance Creek Basins joined. This transition is characterized by the rapid waning of clastic mudstone facies and the predominance of calcareous mudstone facies in the middle to upper portion of the core (235-125 m depth, facies association B). Balanced-filled lake conditions prevailed until evaporites deposited near the top (<125 m depth, facies association C) of the core, indicating an under-filled lake condition (Figure 12c).
Figure 12. Lake-level evolution of Laramide basins depositing the Green River Formation, 49.5-48.0 Ma ago. Schematic cross-sections show paleohydrologic flow according to published reconstructions (9). Schematic P4 core litholog shows three facies associations deposited at each evolution stage of Lake Uinta. A) At ~49.5 Ma, the overfilled Greater Green River Lake and the Uinta Lake flow into the Piceance Creek Lake. As a terminal basin, the Piceance Creek Lake acts much as the present-day evaporative Great Salt Lake or the Dead Sea. B) At ~48.7 Ma, Uinta Lake and Piceance Creek Lake joined over a subsumed Douglas Creek arch, and balanced-filled conditions prevailed as freshwater input was proportional to evaporation rate. Under profundal, meromictic conditions, calcareous mudstones with the richest oil-shale zones were deposited at this time. C) At ~48.0 Ma, Lake Uinta became a terminal, under-filled basin, probably by tectonic alteration of watersheds, that led to evaporative conditions in the basin.
The upward-decreasing trend in the BI log and the eventual cessation of bioturbation in core P4 (Figure 4) has implications for the relationship between bioturbation and lake conditions. During the initial overfilled conditions, bioturbation is active (BI: 2-3, and up to 5). The subsequent period of balanced-filled, deeper conditions shows bioturbation decreasing and then ceasing due to the lack of oxygen (also indicated by the presence of oil shale). Bioturbation is absent through the top portion of the core where massive dolomitic mudstones and nahcolite evaporite deposits indicate hypersaline, but shallower, conditions.

The lower portion of core P4 correlates with the transitional interval of Remy (5), who describes the interval as a period of lake level transgression. At this time, the Uinta Basin was separated from the Piceance Creek Basin by the Douglas Creek arch. The prevailing hydrologic gradient led overflow waters of both the Uinta and Greater Green River Basins to flow into the Piceance Creek Basin, which served as a closed terminal basin (9); see Figure 12a. Prior to the deposition of the Mahogany Zone, the Piceance Creek and Uinta Basins were joined over the Douglas Creek arch and formed a single Lake Uinta (9); see Figure 12b. After the deposition of the Mahogany Zone, conditions reversed. The Uinta Basin eventually became the terminal basin in the hydrologic system (Figure 12c).

Oil shale was deposited in the upper Green River Formation during the deep stages of Lake Uinta. The richest oil shale zones are the Mahogany Zone, R6, and the lower portions of R8 (2, 23). These zones were deposited during the transition from the small, over-filled basin of Lake Uinta to a large, balanced-filled basin incorporating both Lake Uinta and the Piceance Creek Basin. Anoxic conditions at the bottom of Lake Uinta, obligatory for the preservation of organic materials comprising oil shale deposits, suggest that the lake was meromictic and profundal during the deposition of oil shale.

The perceived problematic transition from deep-water calcareous mudstones to shallow-water evaporites without intervening basin-margin clastic input can be explained by the deposition of terminal fan deltas. Such deltas, commonly developed at modern arid lake margins, are described by Pusca (4) in the lower part of the Green River Formation. In the terminal fan delta model during arid periods, surface runoff quickly infiltrates the arid soil or evaporates before reaching the lake. As a result, clastic sediments are deposited as sub-aerial fans, and sediment input to the lake becomes negligible. The resumption of wetter conditions would have delivered the clastic sediments of the Horse Bench sandstone to the site of core P4. Although Pusca (4) identifies terminal fan deltas in the lower part of the Green River Formation, the marginal lacustrine strata that deposited contemporaneously with the upper portion of core P4 are likely not preserved along the Uinta Basin’s southern rim due to Neogene and Quaternary erosion (8).
Conclusions

Oil shale

- Oil shale zones of the upper Green River Formation in the eastern Uinta Basin, Utah were deposited during profundal, meromictic, lacustrine conditions.
- In core P4, oil shale is a calcareous or dolomitic mudstone with high kerogen content.

Sedimentology of core P4

- Core P4 has six facies: clastic mudstones, calcareous mudstones, dolomitic mudstones, sandstones, evaporite (nahcolite), and tuff.
- The six facies are divided into three facies associations: (A) relatively shore-proximal facies association dominated by clastic mudstones (235-358 m depth), (B) deep-basin facies association dominated by calcareous mudstones (125-235 m depth), and (C) evaporating-basin facies associations, characterized by nahcolite and massive dolomitic mudstones (60-125 m depth).
- Facies associations A, B, and C were deposited in an overfilled, balanced-filled, and under-filled lake basin, respectively.
- The bioturbation index log of core P4 can be used as a proxy for bottom-water oxygen level. The BI log’s upward-decreasing trend supports the interpretation of overfilled, balanced-filled, and under-filled lake basins.

Depositional history of the upper Green River Formation in the Uinta Basin (49.5 – 48.0 Ma)

- First, an overfilled, fluctuating holomictic, and siliciclastic-influenced lake system transitioned to a balanced-filled lake system as the water level rose in the Uinta Basin, subsuming the Douglas Creek arch and filling the adjacent Piceance Creek Basin.
- Second, a balanced-filled, profundal, and often meromictic lake system hosted the deposition of the richest oil shale zones during the unification of the Uinta and Piceance Creek Basins.
- Third, an underfilled, evaporitic, and terminal fan-dominated lake system commenced as the Uinta Basin separated from the Piceance Creek Basin.
Reservoir Modeling

Most large-scale oil shale processing operations involve mining and retorting at the surface. In-situ oil shale retorting is an attractive alternative to ex-situ technologies due to reduced environmental impacts from surface disturbance, water requirements, and waste management (24). However, in-situ technologies are still in the development stage and include more uncertainty, especially at large scales. Kerogen, the organic component of oil shale, is a solid that must be converted to a flowing fluid in order to be produced. With in-situ processing, the oil shale must be heated underground until the oil can flow.

In order to model any type of in-situ technology, understanding the fundamental processes is necessary. These fundamental processes include heat transfer through the reservoir, chemical kinetics of kerogen pyrolysis or combustion, geomechanics, multiphase flow, and other factors due to process variations.

Current In-Situ Processing Strategies

Shell Oil Company has been the most aggressive to this point with in-situ oil shale technology development. They have tested their InSitu Conversion Process (ICP) at a pilot scale facility on private land in the Piceance Creek Basin. The ICP consists of resistive, down hole heaters slowly supplying heat to the reservoir for a period of years. After this extended heating period, Shell reports that a high-quality oil is produced. The heating wells are arranged in a hexagonal pattern with 6 heating wells surrounding a production well. Shell is also testing a freeze wall technology that will surround the heater wells. The purpose of the freeze wall, where coolants are circulated underground to create an ice barrier, is to prevent groundwater contamination (25).

ExxonMobil is developing an in-situ oil shale extraction technology known as the Electrofrac process. First, they create hydraulic fractures in the oil shale reservoir. Next, they inject conductive material into the fractures and use resistive heating to heat the reservoir. With the Electrofrac technology, ExxonMobil maximizes heat transfer efficiency by increasing heat transfer area where the conductive material has been injected (26).

American Shale Oil (AMSO) is developing the Conduction, Convection and Reflux (CCR) process. In this process, two horizontal wells, a heater and a producer, are drilled at the bottom of the pay zone. Heat is supplied to the bottom of the reservoir, the kerogen decomposes to lighter products, and the hot vapors rise to the cooler top of the reservoir and reflux (27). This process can be engineered to create high quality oil.

The EcoShale In-Capsulation process developed by Red Leaf Resources combines the benefits of ex-situ and in-situ processing strategies. In their process, a rectangular impoundment (e.g. the
“capsule”) is excavated at the surface and lined with clay. Circulation pipes attached to natural gas burners are installed into the open capsule, which is then filled with mined oil shale. The capsule is covered by native soil and overburden for environmental reclamation, and the shale in the capsule is slowly heated in-situ (28). Advantages of this strategy include that the properties in the capsule are more easily controlled than in a traditional reservoir and that heat transfer is more efficient because the previously mined shale is fragmented.

Mountain West Energy has developed their In-Situ Vapor Extraction (IVE) technology where hot methane gas is injected into the reservoir to pyrolyze the kerogen. Following pyrolysis, shale oil is produced. IVE has been successfully tested in the Naval Petroleum Reserve #3 at the Tea Pot Dome Field near Casper, Wyoming (29).

**Modeling Considerations**

Kerogen, the organic solid in oil shale, is insoluble in most solvents. Therefore, pyrolysis is a common method for decomposing kerogen into liquid and gaseous components. For any in-situ oil shale retort, the kerogen in the reservoir must be heated to a pyrolysis temperature of 350°C – 500°C. Heat that is supplied to the reservoir through a heating well is transferred through the reservoir by conduction and convection. Acceptable heating efficiency is essential to any successful in-situ operation. Temperature control in a reservoir is also a significant challenge due to the complexity of temperature profiles that develop as a result of kerogen pyrolysis kinetics, thermodynamics, and multiphase flow.

The chemical mechanism and kinetics of kerogen pyrolysis are uncertain. Thermal Gravimetric Analysis (TGA) is often used to measure the kinetics of oil shale pyrolysis. Typically, the oil shale is crushed to minimize any heat transfer resistance. Results from the TGA studies reported in Appendix E of this report give a distribution of activation energies, which add additional complexity to the kinetic model. The current consensus is that isoconversion models are theoretically and physically appropriate for describing kerogen pyrolysis. Kerogen structure is widely unknown and may vary significantly within and between resources. Because of this complexity, kerogen compositional behavior and decomposition mechanisms can be difficult to predict. Chemical lumping (grouping) can be used to model compositional behavior.

Combustion process options can be very attractive for oil shale production. In-situ combustion can significantly lower heat generation requirements for oil shale pyrolysis, resulting in a more efficient and economical process. Understanding coke and kerogen combustion in the reservoir is essential for engineering and predicting the behavior of this type of process.

For in-situ thermal processes, inorganic rock decomposition can also take place when temperatures are high. Carbonate rock decomposition could be a significant source of CO₂ emissions.
Geomechanics have a significant impact on the behavior of underground reservoirs. In oil shale reservoirs, the geomechanics are somewhat unique due to the thermal treatment of the rock. Evidence suggests that permeability is created as the rock is heated. Subsidence may also occur as the rock is changed and weakened due to heating.

Resource heterogeneity also has a significant role in reservoir engineering. The detailed characterization of Uintah Basin oil shale resource described in the first section of this report is an example of the type of analysis that is necessary for accurate oil shale reservoir simulations.

Flow characteristics in oil shale reservoirs can be quite complex. Depending on the process design and reservoir characteristics, models are needed to accurately represent flow characteristics. Water, oil, gas, organic solid, and inorganic solid flow behavior in an oil shale reservoir is different from that of a conventional reservoir due to the high temperatures and other factors. The geologic information from U059 (core P4) was converted to wt% hydrocarbon (organic matter or kerogen), and used directly in the reservoir simulation model.

**In-situ Prototype Model**

Pyrolysis of kerogen produces a complex mixture of oil, gas, and residue. For the reservoir simulations described here, the following reaction mechanism, which employs properties of lumped representative components, was used (30).

1. Kerogen $\rightarrow$ Heavy Oil + Light Oil + Gas + CH$_4$ + Char (capitalize Char, Coke)
2. Heavy Oil $\rightarrow$ Light Oil + Gas + CH$_4$ +Char
3. Light Oil $\rightarrow$ Gas + CH$_4$ + Char
4. Gas $\rightarrow$ CH$_4$ + Char
5. Char $\rightarrow$ CH$_4$ + Gas + Coke

All reactions were assumed to be first order, and kinetic parameters from a previous study (30) were used. The heat of reaction was assumed to be 46.5 kJ/gmole for each reaction based on similar reactions from the template input files of the thermal simulator used in the study. Overall heats of reaction of kerogen pyrolysis to oil have been reported previously (31). Detailed thermochemical studies with individual products would be necessary to assign heats of reactions of each individual reaction in the above mechanism. Sensitivity studies on the heats of reaction values showed that this parameter does not affect important production parameters in a significant manner (32).
Stoichiometry was approximated based on the molecular weights and on hydrogen to carbon ratios chosen for each component to force a mass balance. Table I lists molecular weights and two variations of the hydrogen to carbon ratio for the representative components in the kerogen pyrolysis mechanism. The first column of values for the H/C ratio is based on a mechanism and model developed by Braun and Burnham (30). The second column of values for the H/C ratio is based on the more realistic hydrogen to carbon ratio of 1.50 for Green River oil shales (32).

<table>
<thead>
<tr>
<th>Component</th>
<th>Molecular Weight</th>
<th>Hydrogen/Carbon Ratio</th>
<th>Hydrogen/Carbon Ratio (Alternate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kerogen</td>
<td>670</td>
<td>1.05</td>
<td>1.50</td>
</tr>
<tr>
<td>Heavy Oil</td>
<td>441</td>
<td>1.64</td>
<td>1.52</td>
</tr>
<tr>
<td>Light Oil</td>
<td>152</td>
<td>2.27</td>
<td>1.52</td>
</tr>
<tr>
<td>Gas</td>
<td>54</td>
<td>2.5</td>
<td>1.62</td>
</tr>
<tr>
<td>Methane</td>
<td>16</td>
<td>4.0</td>
<td>4.0</td>
</tr>
<tr>
<td>Char</td>
<td>12.4</td>
<td>0.6</td>
<td>0.39</td>
</tr>
<tr>
<td>Coke</td>
<td>12.5</td>
<td>0.45</td>
<td>0.34</td>
</tr>
</tbody>
</table>

Simulations were run with both columns of H/C ratios. The accuracy of the mass balance in the original kinetic model was not sufficient for the simulator, so we forced a mass balance without elemental balance for the first set of values. The second set of values forces a mass balance with an H and C elemental balance. The results for the second set of values (more rigorous) show that production rates, temperatures, produced quantities, etc., are relatively insensitive to hydrogen/carbon ratios.

It should be noted that stoichiometric coefficients used in this reaction scheme are not unique. They are simply estimated to force mass and elemental balances based on approximated molecular weights and hydrogen to carbon ratios of each representative component.

STARS, a thermal-compositional simulator coupled with chemical kinetics developed by the Computer Modeling Group, was used to solve mass and energy conservation equations with necessary constraint equations and physical models (33).
Geometry

The well geometry used in the simulations was loosely based on Shell’s ICP pilot scale test (2). Six heating wells spaced 53 feet (16.2 m) apart surround one production well as shown in Figure 13. The thickness of the simulated reservoir was 50 feet (15.2 m) based on data obtained from the U059 well in the Uintah Basin (see next section for additional information). Due to symmetry, only a triangular wedge was simulated as shown in Figure 14. The results from this simulated section can be repeated to represent the field.

![Figure 13. Aerial view of well geometry for reservoir simulations.](image1)

![Figure 14. Simulated triangular wedge.](image2)

The triangular wedge was discretized into 21 vertical, 1-19 wide, and 1-10 length (10 blocks being the height of the triangle from an aerial view) blocks using CMG Builder.

Initial conditions
Gamma-ray log data from UGS for the U059 well (referred to as P4 in the Geological Characterization section) in the Uinta Basin (33) was used to estimate the weight percent of hydrocarbons in the oil shale (e.g. kerogen). The kerogen-rich section of the well is from 665 feet to 715 feet (202.7- 217.9 m) deep, and the kerogen weight percent varies from 12.5 wt% to 25 wt%. Table II shows the weight percent of kerogen at different depths in the well. The information in this table was used to calculate the initial kerogen volume at each depth. The remaining volume was assumed to be inorganic rock.

Table II. U059 (or P4) Well Survey Data

<table>
<thead>
<tr>
<th>Depth(ft)</th>
<th>wt% of HC</th>
</tr>
</thead>
<tbody>
<tr>
<td>665-670</td>
<td>12.5</td>
</tr>
<tr>
<td>671-680</td>
<td>12.5</td>
</tr>
<tr>
<td>681-690</td>
<td>14</td>
</tr>
<tr>
<td>691-694</td>
<td>15</td>
</tr>
<tr>
<td>695-700</td>
<td>16</td>
</tr>
<tr>
<td>700-710</td>
<td>25</td>
</tr>
<tr>
<td>710-715</td>
<td>16</td>
</tr>
</tbody>
</table>

The porosity of the initial rock was calculated for each layer. Porosities ranged from 0.3 to 0.6. To obtain these values, it was assumed that kerogen nearly filled the pore space in the rock. The initial pressure and temperature assigned to the reservoir were a constant 1000 psi and 80°F (27°C). The values are typical of a reservoir that is about 2800 feet deep.

Production strategy

The reservoir was directly heated with two vertical injection wells to simulate resistive or burner heaters. These heaters heated uniformly from the top to the bottom of the well. Each heater supplied 50,000 BTU/day to the reservoir for a four-year time period. Production was pressure controlled by the producer. For the base case simulation described here, the following conditions were applied: BHP = 100 psi; H/C = 1.05 with associated mass balance + stoichiometry; and U059 well data.
Results

Results from this simulation are shown in the next series of figures. Cumulative oil and gas production over a four-year period is plotted in Figure 15.

No significant quantity of oil is produced prior to 400 days of heating. This time delay represents the time required to convert solid kerogen to producible oil with the given heating rate, well geometry, reservoir characteristics, and process parameters.

The oil production rates in Figure 16 show a maximum rate of approximately 1.2 bbl oil/day occurring two years after the heating is initiated. To convert to bbl oil/day/acre, the rate is multiplied by 30. Oil production rates are low, but oil production rate and quantity are a strong function of temperature history in the reservoir. With the pyrolysis kinetic parameters and mechanism used in this simulation, much of the kerogen was converted to residue and gas rather than to oil.
Figure 16. Oil and gas production rates.

Figure 17 shows the energy efficiency of the heating strategy. After four years, approximately 50% of the heat supplied to the reservoir is lost to overburden and underburden. To minimize such losses, changes in heating patterns, histories, and strategies are required. For example, pyrolysis could be followed by in-situ coke combustion to improve heating efficiency.

Figure 17. Energy supplied to reservoir and energy lost to under/overburden.

Figures 18, 19, 20, and 21 show a comparison of three simulated grid blocks: one near the heater (block 18, 10, 11), one far from the heater (block 10, 1, 11), and one in the middle of the section.
(block 14, 5, 11). In all four figures, the red line represents the location near the heater, the blue line represents the location far from the heater, and the orange line represents the location in the middle. Near the heaters (see Figure 18), the temperature rises rapidly. However, temperature changes in the other two blocks indicate that conduction through the reservoir is slow. The high temperatures near the heaters are excessive but may be required to generate a temperature gradient that results in heat conduction through the reservoir in a reasonable time. It may take up to 700 days to supply sufficient heat for pyrolysis far from the heater under these conditions. Note that the temperatures reported here are specific to the heat input strategy used in the simulations. Figure 19 shows that kerogen conversion was rapid at the high temperatures near the heater. Figure 20 shows the oil saturation versus time at different locations in the reservoir. Coking was also significant due to high temperatures near the heaters, as shown in Figure 21.

Figure 18. Temperature history comparison for three distances from heaters.
Figure 19. Kerogen concentration comparison for three distances from heaters.

Figure 20. Oil saturation comparison for three distances from heaters.
Additional simulations were run to explore the sensitivity of results to back pressure in the reservoir. Increasing reservoir pressure increases the residence time of organic components, which has compositional implications. Cumulative production results for a case with BHP = 1000 psi are shown in Figure 22. When compared to the base case simulation in Figure 15 (BHP = 100 psi), it is observed that this pressure increase caused increased oil conversion to gases, an expected result due to the increased residence time. In addition, residue creation was greater with the higher bottom hole pressure.
The net energy gain/loss was estimated for this type of process assuming the following: (1) 15 wt% kerogen in the oil shale source rock, (2) all kerogen converted to recoverable oil, (3) source rock heated from 25°C to a retort temperature of 350°C, and (4) heat of reaction for kerogen conversion of 370 kJ/kg. In this idealized estimate, 17 units of energy were produced per unit of energy required. The base case simulation results show 50% reservoir heating efficiency at the end of four years. If resistive heating is used and one assumes 36% electricity generation efficiency and 50% reservoir heating efficiency, a net energy gain of 3 units of energy out per unit of energy required is calculated. For their pilot scale ICP test, Shell estimated a net energy gain of 3 units out per unit of energy required with resistive heating supplied.

Preliminary estimates of the carbon footprint for this type of process were also calculated based on the following assumptions were made: (1) underground natural gas heating, (2) production of 33 API crude oil, and (3) the assumptions mentioned in the energy gain/loss estimate. Assuming 100% heating efficiency, 18 kg CO₂/bbl oil are emitted. If 50% heating efficiency is assumed, 36 kg CO₂/bbl oil are emitted. These estimates do not include any CO₂ emissions due to combustion inefficiency or carbonate mineral decomposition.

No estimates for water requirements were made because water is not necessarily required for in-situ oil shale conversion processes. When using resistive heating, water is required for electricity generation but is not directly required for oil shale processing.
Conclusions

A realistic geologic representation of the Green River oil shale formation was used to study the potential of an in-situ production process based on direct heating. A rigorous kinetic model was incorporated into a reservoir simulation framework. Oil production rates were low, amounting to about 40 bbl/day/acre. A significant portion of the kerogen was converted to non-condensable gas. Coke and char were also generated in the process. The net energy gain was about 3 units of energy out per unit of energy in due to significant heat losses to underburden and overburden. The net CO₂ production was about 18 kg/bbl of oil produced in an ideal situation, but under more realistic assumptions, CO₂ production increased to 36 kg/bbl. The study showed that direct heating for oil production from shale may be feasible process, but a number of technical challenges remain.
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References


