APPENDIX C

In-situ Production of Utah Oil Sands

Final Project Report
Reporting period: June 21, 2006 to October 21, 2009

Milind Deo, Royhan Gani C. K. Huang, and Pete Rose
Department of Chemical Engineering
University of Utah

October 2009

DOE Award Number: DE-FC26-06NT15569

Submitted by:
Institute for Clean & Secure Energy
155 South 1452 East Room 380
Salt Lake City, UT 84112
Project Objectives

The objective of this project is to evaluate and rank a variety of in-situ heavy oil production method for the production of bitumen from a representative Utah oil sand formation within the Uinta Basin. Tools to be employed include a thorough survey of the geology of oil-sand intervals, a survey of various approaches described in the literature, and a numerical simulation study to test the most promising oil-extraction approaches applied to a Utah resource.

Summary of Project Outcomes

Two oil sand reservoirs located in Utah’s Uinta Basin were considered for analysis: Whiterocks, a small, steeply dipping, contained reservoir containing about 100 million barrels, and Sunnyside, a giant reservoir containing over four billion barrels of oil in place. Cyclic steam stimulation, steam assisted gravity drainage, and in-situ combustion processes were considered for the production of oil from these reservoirs. Different well configurations and patterns were examined. It was found that the application of steam-based in-situ processes would be feasible but challenging for Utah oil sands. For most configurations, the steam to oil ratios were higher than five, indicating marginal economic viability. Additionally, the water production rates were high. The in-situ combustion process was simulated with and without the presence of a hydraulic fracture for a homogeneous reservoir. The nature of the combustion front was radial without the fracture and linear with the fracture. Even though the process appears feasible, rigorous evaluation with an appropriate geologic model will be necessary to determine technical and economic viability.

Presentations and Papers


Characterization of Oil Sands

Bitumen is the principal organic material found in oil sands. While the world’s largest oil sands resources are found in the province of Alberta, Canada, major oil sands resources are also found in Utah. The characteristics of bitumen in comparison to other feedstocks are shown in Table 1. While bitumen does have high densities and low heating values compared with crude oil, its hydrogen to carbon ratio is reasonably favorable when compared with other unconventional fuels.

Table 1: General characteristics of oil sand bitumen in comparison to other feedstocks.

<table>
<thead>
<tr>
<th></th>
<th>Crude oil</th>
<th>Heavy Oil</th>
<th>Bitumen</th>
<th>Kerogen</th>
</tr>
</thead>
<tbody>
<tr>
<td>SG</td>
<td>0.85</td>
<td>0.95</td>
<td>0.98</td>
<td>1</td>
</tr>
<tr>
<td>C</td>
<td>86</td>
<td>86.5</td>
<td>85.1</td>
<td>79</td>
</tr>
<tr>
<td>H</td>
<td>13.6</td>
<td>11.5</td>
<td>11.3</td>
<td>10</td>
</tr>
<tr>
<td>N</td>
<td>0.2</td>
<td>0.5</td>
<td>1.6</td>
<td>2</td>
</tr>
<tr>
<td>S</td>
<td>0.2</td>
<td>1</td>
<td>1.5</td>
<td>1</td>
</tr>
<tr>
<td>O</td>
<td>0</td>
<td>0.5</td>
<td>0.5</td>
<td>7</td>
</tr>
<tr>
<td>H/C</td>
<td>1.90</td>
<td>1.60</td>
<td>1.59</td>
<td>1.52</td>
</tr>
<tr>
<td>Heating</td>
<td>42</td>
<td>38</td>
<td>35</td>
<td>34</td>
</tr>
<tr>
<td>Value (MJ/kg)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The Utah oil sand reservoirs containing significant quantities of oil are listed in Table 2 along with a few other characteristics about the deposits.

Table 2: Some characteristics of Utah oil sand reservoirs (adapted from [1]).

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Areal Extent (Square Miles)</th>
<th>Range of Gross Thickness</th>
<th>Oil in place (in millions of barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Asphalt Ridge</td>
<td>20 to 25</td>
<td>10 to 135</td>
<td>800 - 1000</td>
</tr>
<tr>
<td>PR Spring</td>
<td>240 to 270</td>
<td>10 to 80</td>
<td>4000 - 5000</td>
</tr>
<tr>
<td>Sunnyside</td>
<td>35 to 90</td>
<td>15 to 550</td>
<td>3500 - 4000</td>
</tr>
<tr>
<td>Whiterocks</td>
<td>0.6 to 0.75</td>
<td>1000+</td>
<td>65-125</td>
</tr>
</tbody>
</table>
Studies in this report focus primarily on the Whiterocks and Sunnyside oil sand reservoirs. Locations of these resources can be seen in Figure 1. The Whiterocks reservoir is located in the northern section of the Uinta Basin while the Sunnyside reservoir is located on the Basin’s southwest flank. The Whiterocks formation, a small, contained deposit, consists of relatively homogeneous sandstone with high viscosity bitumen [2,3]. The Sunnyside formation, one of the largest oil sands deposits in the state, is characterized by rugged terrain, uneven quality, consolidated oil sands, and very high viscosities [2,3].

Figure 1: Locations of the prominent oil sand deposits in the State of Utah (from [2]).

General formation properties of significant Utah deposits, including the White Rocks and Sunnyside formations, are also shown in Table 2 [2]. The biggest difference between the Utah and the Canadian bitumen is that the viscosity of Utah bitumen at reservoir conditions is 30,000 to 300,000 cp, about one or two orders of magnitude larger than the Canadian bitumen. The
Sunnyside formation is characterized by ultra-high viscosity bitumen while the Whiterocks deposit contains a relatively “lighter” bitumen. Other major distinguishing features between Utah and Canadian oil sands include the higher level of sand consolidation, the lower resource quality (weight percent bitumen in the oil sand mixture) and the significant reservoir heterogeneity exhibited by Utah oils sands.

Survey of In-situ Oil Sand Production Approaches

Most large-scale oil sands production strategies involve ex-situ processes, e.g. strip mining followed by bitumen extraction [1,2]. In-situ production of oil sands bitumen offers an excellent alternative to the ex-situ processes. In addition to leaving the landscape relatively undisturbed, in situ processes allow for partial upgrading of oil sands, leaving heavier, less profitable components of the bitumen in the subsurface. Some in-situ methods use much less water and generate less CO₂ than ex-situ methods. In addition, in-situ approaches allow for the exploitation of much deeper oil sand formations—where the cost of removing the overburden is prohibitively expensive.

In-situ oil sands production is increasing in Canada. In 2007, in-situ production accounted for 41% of the 1.3 million barrels produced each day [4]. In-situ technologies might be particularly attractive for the State of Utah because of its arid climate and because of the proximity of some oil sands deposits to environmentally sensitive areas.

Steam processes, including cyclic steaming, steamdrives, and Steam-Assisted Gravity Drainage (SAGD) are the most common in-situ production processes being used globally for oil sands production. Likewise, in-situ combustion is an emerging in-situ process that has achieved some early success in Canada’s vast oil sand deposits. A recently created process called Toe-to-Heel Air Injection (THAI) takes advantage of the best qualities of the SAGD and in situ combustion approaches and uses a horizontal well both to direct the combustion process and to collect the mobilized bitumen [5]. Even though these concepts are relatively simple and have been used successfully in other countries, significant challenges exist in adapting these technologies to Utah’s lenticular oil sands deposits.

Cyclic steam stimulation, SAGD, and in-situ combustion are the in-situ processes considered in this report. A survey of other in-situ processes for the production of oil sands can be found in [6].

Cyclic Steam Stimulation (CSS)

Perhaps the simplest, most reliable, and most commonly practiced form of in-situ production is cyclic steam injection, also known as “huff-and-puff” [7,8]. With this approach, steam is injected at high pressures and temperatures (550°F or higher) and is then allowed to soak. The pressure dilates or fractures the formation and the heat reduces the viscosity of the bitumen. The heated
bitumen is then pumped to the surface using downhole pumps in the injection well (Figure 2). The process is repeated in a cyclical fashion until saturations become non-productive [9].

Although the cyclic steam process is simple and reliable, recoveries are relatively low (~25%) and large amounts of water are required to generate steam. Likewise, the energy to generate the required steam is expensive.

Figure 2: Schematic of the cyclic steam stimulation process showing the injection phase, the soak period and production from a single well (from [6]).

**Steam Assisted Gravity Drainage (SAGD)**

SAGD has become the dominant technology employed in a variety of heavy oil and bitumen recovery processes, with Canadian development leading the way. A number of oil companies are currently involved in pilot and commercial applications of the SAGD process. In SAGD, two horizontal wells are placed near the bottom of a formation as shown in Figure 3. Steam is injected through the upper well, which, due to buoyant forces, rises through the formation to create a steam chamber near the top of the formation. Steam mobilizes the bitumen by lowering its viscosity, and the bitumen then flows downward. The production well, placed about 5 m below the injection well, is used to collect the resulting condensate and the released oil, which is then pumped to the surface. Long horizontal well segments have the potential for higher oil recovery rates. SAGD is the dominant in situ technology because it utilizes the natural tendency
of oil to drain by gravity into production wells and it is a relatively simple process to implement [10,11].

While the SAGD process can lead to high recoveries (up to 60% of the oil in place) and is economically viable, it has several disadvantages. It requires large amounts of water and the energy that is required to generate the required steam is expensive and leads to the production of large quantities of the greenhouse gas CO2. Also, since it relies on gravity drainage, it requires comparatively thick and homogeneous reservoirs.

![Figure 3: Schematic showing the operation of SAGD (from [6]).](image)

**In-situ Combustion**

In-situ combustion is an enhanced oil recovery (EOR) technique that has been widely studied and used in the production of heavy oils since its inception in the mid-1930’s [12-14]. It is a process in which air, oxygen, or oxygen-enriched air is injected into a bitumen reservoir. The air/bitumen mixture is ignited to produce a combustion zone that creates heat and causes the flow of the remaining bitumen to a collector.
In situ combustion offers the advantages of high recovery (60% or more of original oil in place), high efficiency due to self-heating of the reservoir, low cost [15] and low water use, the latter being especially attractive in arid settings such as those in Utah. The injection of pure oxygen in the place of air [16] or the injection of water to produce in situ steam [17] can both significantly improve sweep efficiencies and recoveries. However, the combustion front is difficult to control and some of the resource in place is lost to combustion. Classical in-situ combustion not expected to work well in oil sands unless some scheme is used to provide initial interwell communication and mobility to the bitumen [18].

**Numerical Simulation of In-situ Production of Utah Oil Sands**

Numerical simulation of these processes can give insight into the potential of the resources of interest. First, both SAGD and cyclic steam processes, loosely based on the Whiterocks resource characteristics, were modeled. Second, SAGD and a process involving steam injection with vertical wells were modeled for the Sunnyside resource. In-situ combustion was simulated with a homogeneous hypothetical resource due to complexities associated with modeling this process.

**Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Processes**

*Whiterocks Deposit*

Initial numerical simulation models of the SAGD and cyclic steam production processes based upon the Whiterocks reservoir model were constructed and run using STARS, the thermal compositional simulator developed by Computer Modeling Group, Calgary, Canada [19]. The reservoir was divided into 25 layers of varying thicknesses. These layers were categorized as: rich (r), lean (l), very lean (v), and barren (b). Properties of the various layers used in the simulation are shown in Figure 4. For example, the rich layers were assumed to have the following characteristics: vertical and horizontal permeability of 125 md, porosity of 0.3, and oil saturation of 0.6. The thickness of the 25 layers can be seen in Figure 5, which is a visualization of the permeability of the grid blocks. Red grid blocks represent rich layers, green grid blocks represent lean layers, light blue grid blocks represent very lean layers, and dark blue blocks represent barren layers. Layer 1 in Figure 4 is the layer furthest to the left in Figure 5 progressing to layer 25 as the final layer furthest to the right in Figure 5.
Figure 4: The 25 layers used in the simulation of cyclic and SAGD processes. The categories are rich, lean, very lean and barren.

<table>
<thead>
<tr>
<th>Layer</th>
<th>Category</th>
<th>Perm.</th>
<th>Por.</th>
<th>Sat.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>r</td>
<td>125</td>
<td>0.3</td>
<td>0.6</td>
</tr>
<tr>
<td>2</td>
<td>l</td>
<td>75</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>3</td>
<td>r</td>
<td>125</td>
<td>0.3</td>
<td>0.6</td>
</tr>
<tr>
<td>4</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>l</td>
<td>75</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>6</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>7</td>
<td>l</td>
<td>75</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>8</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>9</td>
<td>v</td>
<td>25</td>
<td>0.15</td>
<td>0.2</td>
</tr>
<tr>
<td>10</td>
<td>l</td>
<td>75</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>11</td>
<td>v</td>
<td>25</td>
<td>0.15</td>
<td>0.2</td>
</tr>
<tr>
<td>12</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>13</td>
<td>l</td>
<td>75</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>14</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>15</td>
<td>v</td>
<td>25</td>
<td>0.15</td>
<td>0.2</td>
</tr>
<tr>
<td>16</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>17</td>
<td>v</td>
<td>25</td>
<td>0.15</td>
<td>0.2</td>
</tr>
<tr>
<td>18</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>19</td>
<td>l</td>
<td>75</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>20</td>
<td>r</td>
<td>125</td>
<td>0.3</td>
<td>0.6</td>
</tr>
<tr>
<td>21</td>
<td>v</td>
<td>25</td>
<td>0.15</td>
<td>0.2</td>
</tr>
<tr>
<td>22</td>
<td>r</td>
<td>125</td>
<td>0.3</td>
<td>0.6</td>
</tr>
<tr>
<td>23</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>24</td>
<td>l</td>
<td>75</td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td>25</td>
<td>b</td>
<td>5</td>
<td>0.1</td>
<td>0</td>
</tr>
</tbody>
</table>

Figure 5: Model of the Whiterocks reservoir constructed in STARS.
Whiterocks is a steeply dipping reservoir \( (75^\circ) \). The model constructed in STARS is shown in Figure 5. It should be noted that if horizontal wells were used, they would cut across the bedding planes in almost a perpendicular manner.

The geometry and the well configurations used are shown in Figure 6. The wells were placed so that the steam chambers would be able to effectively drain oil from the reservoir. For the SAGD process, three pairs of horizontal wells, the SAGD injector and producer, were simulated. The pairs of wells alternated between a location near the bottom of the reservoir and a location and in the middle of the reservoir (290 ft. higher) as seen in Figure 6. This pattern allows for efficient heat and fluid transfer throughout the reservoir. The lower pairs of wells lie on the boundary of the simulation, so only half of each well is calculated. This boundary condition can be repeated to represent more wells in the same pattern. In the cyclic steam simulation, the same geometry and well configurations were used. However, a single vertical well was used as both the injection well and the producer. Bitumen was assumed to be highly viscous dead oil. Fluid properties for this dead oil were assumed. Three components were represented in appropriate phases: water, dead oil, and solution gas. Both types of simulations were performed on a PC. After adjustment of numerical parameters, SAGD simulations required approximately 4 hours while the cyclic steam simulations required over 46 hours.

![Figure 6: Geometry and well configuration used.](image)

SAGD oil production is shown in Figure 7 and the cyclic oil production is shown in Figure 8. In both cases, substantial amounts of oil can be produced from the reservoir. Since the initial water saturation in the reservoir is significant, large amounts of water are also produced. It should be noted that the uncertainty in these simulations can be significant. The simulation results are very sensitive to the rock-fluid properties (relative permeability curves) employed in the simulation. Relative permeabilities at conditions of interest for these formations have not been measured and
“typical” values were used in the simulations. Additionally, the geologic information is assembled using data from one log, so lateral variability is not accounted for. The flow properties are also approximate as they are based on limited laboratory testing.

Figure 7: Oil production in Whiterocks SAGD simulations.
Steam-oil ratios (SOR) in most SAGD simulations averaged about 5-10. Initially, water was assumed to fill the remaining pore space not filled by oil in the simulations (e.g. no gas was present). This initial water saturation, in addition to the injected steam, accounts for the high water cuts. For comparison, the SOR in economic SAGD operations in Canada is about 3. With the geologic conditions employed and the assumed water saturations, it appears that the computed SORs are not very favorable for in-situ oil production in Utah.

**Sunnyside Deposit Modeling**

The conceptual geologic model of the Sunnyside deposit provided by Gwynn [20] and shown in Figure 9 was adapted for reservoir simulations. The thickest zones are about 90 feet in thickness, but these are interspersed with numerous thin and sometimes lean layers. This layered heterogeneous reality represents the most significant challenge to exploiting Utah oil sands resources. For the simulations, the layered geologic model was simplified by using alternating lean and rich zones as shown in Figure 10.
Figure 9: A geologic model of the Sunnyside deposit used in the simulations (from [20]).

Figure 10: A small section of the Sunnyside geologic model used in the reservoir model. The model is 200 feet by 200 feet by 120 feet thick and has alternating rich and lean layers.
The well configurations used in steam injection and production are shown in Figure 8. Conditions were the same for both simulations in order to compare the performance of a SAGD process to a simpler steam flood with vertical wells. In Figure 11, the panel on the left shows a classic SAGD configuration with a horizontal well pair. The panel on the right shows a vertical injector and vertical producer configuration. The injector has been completed in only half of the formation to allow for the steam override. This injector configuration allows for more steam contact in the reservoir than if the vertical injector were completed over the entire formation. In addition to well placement, Figure 11 shows a 2D side view of the domain described in Figure 10. This geologic model is conceptual and approximate. Layers with different richness are represented with different properties but cells within layers have uniform properties. Oil saturation averages about 0.65 for the entire model. This reservoir realization represents a thick tongue in the Sunnyside formation that is sufficiently deep (500+ feet) to contain the steam chamber. A detailed characterization program (with a number of core holes over the entire deposit) will be necessary to obtain a better reservoir model and a better reservoir representation.

Figure 11: The horizontal and vertical well configurations used for steam injection in Sunnyside.

The horizontal well configuration consists of an injection production pair with the injector above the producer at the bottom of the reservoir. The injector in this simulation was 20 feet above the producer. The separation between these horizontal wells is partially determined by horizontal drilling capabilities. Also, it is possible to produce the injected steam before it transfers heat to the reservoir if the wells are too close to each other. In the vertical well configuration, steam is injected at the bottom half of the reservoir as illustrated by the yellow dots in Figure 11 while oil is produced from the entire cross section. These simulations required a few hours of computational time on a fast PC.

Results from the SAGD simulation, including horizontal well production and other parameters, are shown in Figure 12. Because of the high initial water saturation (0.35 average), water
production was consistently high throughout the production period. Once again, SOR ranged from 5-10 throughout the simulated period.

Figure 12: Production rates, cumulative production, etc. for SAGD production from Sunnyside.

The vertical well pair production is shown in Figure 13. The rates and cumulative oil production are much lower in the vertical well case than for SAGD. Heat transfer is likely insufficient from the vertical well, and the distance is too large between the injector and producer wells for economic utilization of steam. These results further demonstrate that production rates may be uneconomically low due to high oil viscosities and limited steam injectivities.
In-situ Combustion

In-situ combustion is considered a highly complicated EOR process from both a practical and a modeling standpoint. In practice, the interplay between the geological heterogeneity of the reservoir and the distribution of the hydrocarbons increases the difficulty of controlling the process. In performing simulations, chemical reaction rates, phase equilibrium calculations, and complicated rock-fluid interactions make numerical stability a challenge. The addition of fracture considerations increases the numerical difficulty since multi-scale flow regions exist in the problem. We examined the use of in-situ combustion in homogeneous media without the additional consideration of complex geology reported for the steam injection simulations in the previous section.

Injecting air in oil sand reservoirs for in-situ combustion requires reasonable permeability. Hydraulic fracturing is a logical method of creating this permeability. To study the impact of fractures and faults, an in-situ combustion simulator for complex fractured media was developed at the University of Utah. The simulator is a discrete-fracture, finite-element model for multiphase reservoir simulation that is based on models described in the late 1970s [21].
The simulator was developed using a modularization concept that divides the development of the simulator into two major modules: physical method module (PM) and the discretization module (DM). The first module provides the property data required in the reservoir model and performs the solution of the governing equations that describe the nature of the reservoir performance. The second module provides the spatial information related to the chosen discretization method.

The in-situ combustion algorithms were first tested with dry (no-water) combustion and then with wet combustion where different amounts of water were co-injected with air. Additional simulation details, including boundary conditions, inlet conditions, and reservoir characteristics, can be found in [22].

The temperature profiles along the injection path (dimensionless) are shown in Figure 14. With wet combustion, the high-temperature plateau is wider due to the effect of water evaporation and re-condensation at the front. This plateau results in better heat utilization and distribution, an additional benefit (combustion besides permeability creation) to hydraulic fracturing with in-situ

![Figure 14: Comparison of temperatures profiles with dry and wet combustion.](image)

While hydraulic fracturing is necessary to improve the air injectivity (or sometimes productivity) and sweep efficiency, the actual effect of the hydraulic fracture depends on its dimension, orientation and system of complexity. Therefore, the near-well displacement in a hydraulically-
fractured in-situ combustion process was studied next. The discrete fracture model in the in-situ combustion simulator is an ideal discretization method for providing a better understanding of flow phenomena in this type of application. The domain used for the study is shown in Figure 15. A five-spot well pattern is used together with full-length and half-length fractures. Additional simulation details are found in [22].

Figure 15: Domain used to study in-situ combustion in an oil sand reservoir with hydraulic fracture. The blue sphere represents the injector and the red sphere represents the producer. FA is the full-length fracture, and FB is the half-length fracture. The yellow square shows the boundary of the simulation domain (symmetry).

The oil saturation distributions with half- and full-length fractures are shown in Figure 16. The injectivity of air improves due to the presence of the fracture and the front is more linear than the front created when only a half-length fracture is present.
Figure 16: In-situ combustion with hydraulic fracture – comparison of half length and full-length fractures. It is seen that the full-length fracture creates a linear front compared to the radial front.
Conclusions

The efficacy of a variety of thermally-enhanced oil recovery methods was examined for the production of oil from Utah oil sands reservoirs. Specific geologic models were used for the evaluation of steamfloods in Whiterocks and in Sunnyside. Cyclic and SAGD processes were found feasible, resulting in significant oil production. However, the water rates were high and the SOR was in the 5-10 range, making economic operation of these processes challenging. A thermal enhanced oil recovery reservoir simulator developed for fractured reservoirs was used to examine the use of in-situ combustion in the presence of hydraulic fractures. The front development and front geometry were observed to be different with hydraulic fractures.

Acknowledgements

The authors would like to acknowledge financial support for the project from the U.S. Department of Energy through the Utah Heavy Oil Program at the University of Utah under grant #00056-55800308. The steam treatment simulations were performed using STARS from the Computer Modeling Group, Calgary, Canada. The authors would like to thank CMG for granting the Academic Licenses for their suite of reservoir simulators.

References


