INTEGRATED RESERVOIR MODELING FOR ENHANCED GEOTHERMAL ENERGY SYSTEMS IN CENTRAL ALBERTA, CANADA

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ABSTRACT

The province of Alberta has a high demand of thermal energy for both industrial and residential applications. Currently, the vast majority of the heat used in these applications is obtained by burning natural gas. Geothermal energy production from deep aquifer systems in the sedimentary basin could provide an alternative source of heat that would be both sustainable and help Alberta reduce greenhouse gas emissions.

To date there has been no geothermal field development in Alberta because the average geothermal gradient of 30 °C/km was considered to be too low for economic geothermal energy generation. However, with technologies for Enhanced Geothermal Systems (EGS), it may be possible to develop geothermal resources from the sedimentary rocks in the Alberta Basin. A feasibility study based on existing and newly gained data is necessary to identify scenarios for geothermal energy production in the region.

In this paper, we investigate the potential of these geothermal energy systems by geological modeling and reservoir simulation in terms of EGS. Geological modeling enables us to map and quantify the subsurface conditions and delineate thermal resources. Reservoir simulation is then used to identify the potential productivity of thermal energy.

A regional scale geological model of the Central Alberta Basin has been developed for an area around Edmonton with a horizontal extent of 200 km x 160 km (Weides et al., in press). This model is based on stratigraphic data from about 7000 wells and includes all major formations from the surface to the Precambrian basement. In Central Alberta, four Devonian carbonate formations and the Cambrian Basal Sandstone Unit are identified as the highest geothermal potential zones. Four formations were selected for more detailed investigations; thermal, hydraulic, and mechanical properties of these formations are obtained from geological databases, literature, and from new laboratory measurements.

Finally, thermal-hydraulic reservoir simulations for a 5 km x 5 km site in the city of Edmonton were performed to evaluate reservoir development concepts. Hydraulic fracturing treatments are simulated for the various geological formations. Different utilization concepts are presented for possible applications of geothermal energy generation in residential, industrial and agricultural areas.

INTRODUCTION

In the western Canadian sedimentary basin (WCSB), low enthalpy geothermal energy (\(<90°C - 190°C\); Williams et al., 2011) is present. Areas in the western part of the basin with temperatures higher than 100°C within the sedimentary rocks may be feasible for electricity generation (Majorowicz and Weides,
2012). However, there are diverse applications other than electricity generation for low enthalpy geothermal energy (Lindal et al., 1973). In central Alberta, geothermal energy could play a role in replacing some fossil-fuel generated heat energy used within industrial processes and/or as an energy source for district heating (Weides et al., in press).

For direct utilization, geothermal wells and the customers using the heat energy need to be in close proximity to one another, however Alberta’s population density is relatively low. The largest amount of energy is needed in specific industrial and administrative centers of the province such as Edmonton, the capital of Alberta. Out of a total of about 3,650,000 people living in Alberta, Edmonton is home to about 1,160,000 people and its population is still growing (Statistics Canada, 2011). Industry, agriculture, residential areas, administrative buildings from the provincial and municipal government, the University of Alberta and other educational institutions, as well as big malls and hospitals are the main energy consumers with a huge part of this energy being used for heating.

The necessary heat is currently provided by burning natural gas with severe environmental impacts. Geothermal energy has the potential to save valuable gas resources and reduce greenhouse gas emissions and the largest geothermal potential lies within the WCSB.

Weides et al. (in press) identified formations with the largest potential for geothermal energy extraction in the Edmonton area. In this study, we present subsequent reservoir simulations showing from which of these formations the largest amount of heat can be extracted, which of the formations need additional engineering in order to be productive, and which is the most economical way to extract the heat. Hydraulic stimulation techniques can be utilized to enhance the reservoir permeability by stimulating existing fracture networks and/or creating new ones. These systems are generally called Enhanced (or Engineered) Geothermal Systems (EGS; Tester et al., 2006). Major stimulation techniques are hydraulic stimulation (gel-proppant fracturing, hybrid fracturing and water fracturing), matrix acidizing, acid stimulation, and thermal stimulation (Economides and Nolte, 2000).

In this paper, we focus on the simulation of conventional gel-proppant treatments. First a pad (fracturing fluid without proppants) is pumped into the formation to open existing fractures and/or create new ones and furthermore propagate these fractures into the formation. Then the slurry (fracturing fluid mixed with proppants) is pumped to transport and distribute the proppants in the fracture, and finally the wellbore is flushed, ideally leaving a proppant filled conductive fracture (Economides and Nolte, 2000).

In addition, we studied the role of well and fracture arrangements within the reservoir rocks and from this information compare the four formations in terms of energy, economics, CO₂ emission savings, and natural gas savings. This integrated approach gives us insight about which formation is most suitable for heat generation for specific applications in the vicinity of the city of Edmonton.

**GEOLOGICAL MODEL**

A 3D geological model was developed for an area in central Alberta, located around the city of Edmonton (Weides et al., in press). This area is approx. 160 km x 200 km in size, and the thickness of the sedimentary succession from ground surface to the top of the Precambrian crystalline basement is between 1.8 km and 3.5 km.

The model is based on the stratigraphy identified by numerous well logs from the Alberta Geological Survey (AGS) database. In total, stratigraphic tops from 6916 wells were used to build the model. While this database is extensive it is also biased towards hydrocarbon-rich strata and areas since most of the data comes from hydrocarbon exploration and production wells. A high amount of data exists for the Mesozoic succession (> 6500 wells in the Lower Cretaceous) and hydrocarbon-bearing Upper Paleozoic strata (> 2000 wells in the Upper Devonian). In contrast, only a small number of wells have been drilled in the strata below the Upper Devonian carbonates. In the central Alberta study area, 72 wells have reached the top of the Middle Devonian Elk Point Group, of which 16 wells were drilled into the Cambrian strata, with 13 penetrating the top of the Precambrian basement in a depth between 1769 m and 3533 m.

No seismic information was used in the development of the 3D model; therefore, no information on faults was integrated into the model.
Due to the large scale of the model (the study area is approx. 160 km x 200 km) only regionally extensive formations have been modelled. The lithostratigraphic 3D model comprises 20 different geological units, of which 14 are in the Paleozoic strata and six are in the Mesozoic- and Cenozoic-aged strata (Figure 1).

Figure 1: Three dimensional geological model of the study area. The model is based on stratigraphic picks from about 7000 wells and potential geothermal reservoir units are indicated by the letter “G”; from Weides et al. (in press).

POTENTIAL TARGET FORMATIONS

Potential target formations that are present in the vicinity of the city of Edmonton are the three Devonian carbonate (carb.) formations and the Basal Sandstone (Sst.) Unit. A summary of the most important properties is given in Table 1.

Table 1: Summary of the main properties of the four potential target formations for geothermal energy extraction in the Edmonton Area.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Wabamun</th>
<th>Nisku</th>
<th>Cooking Lake</th>
<th>Basal Sst.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth [m]</td>
<td>1,193</td>
<td>1,312</td>
<td>1,615</td>
<td>2,427</td>
</tr>
<tr>
<td>Thickness [m]</td>
<td>106</td>
<td>56</td>
<td>81</td>
<td>33</td>
</tr>
<tr>
<td>Hor. Perm. [mD]</td>
<td>2.8</td>
<td>9.7</td>
<td>10.4</td>
<td>1.6</td>
</tr>
<tr>
<td>Vert. Perm. [mD]</td>
<td>0.5</td>
<td>1.3</td>
<td>0.4</td>
<td>0.6</td>
</tr>
<tr>
<td>Porosity [%]</td>
<td>8.0</td>
<td>8.0</td>
<td>8.2</td>
<td>8.9</td>
</tr>
<tr>
<td>Temp. [°C]</td>
<td>45</td>
<td>49</td>
<td>60</td>
<td>91</td>
</tr>
</tbody>
</table>

RESERVOIR AND STIMULATION MODELS

A 5 km x 5 km square area around the Edmonton city airport was cut out of the regional scale geological model to build a local scale reservoir model. Some layers of the geological model were split into finer formations where more detail was necessary. The thickness of those formations was estimated based on boreholes within a 25 km x 25 km square around the center of the reservoir model. In order to reduce computation times and increase accuracy, the reservoir model was divided into 3 separate models in different depth ranges around the target formations (Figure 2).

For the fracturing simulations, only one model was built for which the thicknesses from the center of the reservoir model was taken with no lateral change. The parameterization of both models is based on data from the closest wells from geological databases, literature, and new laboratory measurements. The data from all these different sources was integrated to build the models.

The reservoir pressure $P_p$ at depth $z$ was calculated based on reservoir fluid densities $\rho$ from Connolly et al. (1990) and the acceleration of gravity $g$ using Equation 1.

$$ P_p = \rho gz $$  \hspace{1cm} (1)

The total compressibility $c_t$ was calculated by Equation 2:

$$ c_t = S_w c_w + S_g c_g + c_r $$  \hspace{1cm} (2)

where $S_w$ is the water saturation, $S_g$ is the gas sat., $c_w$ is the water compressibility, $c_g$ is the gas comp. and $c_r$ is the bulk rock compressibility.
Porosity and permeability data were obtained from core tests reported in the Alberta general well data file and new laboratory measurements (for the Cambrian Basal Sandstone Unit; from Weides, ongoing PhD thesis). These plug-scale values were first scaled-up to the well scale, and then the well scale values were scaled-up to average values representing the regional scale. Data of the Devonian target formations came from wells within a 25 km x 25 km square area around the center of the model. Below the Cooking Lake Formation, data from the whole basin was taken.

For deep formations within the WCSB, a normal stress regime with vertical stress ($\sigma_V$) > maximum horizontal stress ($\sigma_H$) > minimum horizontal stress ($\sigma_h$) can be expected. The average gradient of $\sigma_V$ is 23.8 MPa/km and the average gradient of $\sigma_h$ is 16.6 MPa/km. The fracture pressure (pressure at which a new fracture within the formation is opened) gradient is about 19 MPa/km for the whole WCSB (Hawkes, 2005).

Keeping these average values in mind, we calculated the minimum horizontal stress gradient based on Poisson’s ratio, $\nu$ and the vertical stress using Equation 3 (Zoback, 2007).

$$\sigma_h = \frac{\nu}{1-\nu} (\sigma_v - P_p) + P_p \tag{3}$$

Data from the world stress map (Heidbach et al., 2008) suggests the direction of the maximum horizontal stress to be approximately 45° and hydraulic fractures will most likely tend to develop perpendicular to this direction (Yew, 1997).

Mechanical data was derived from literature and new laboratory measurements from the Basal Sandstone Unit. From Haug et al. (2007), the static Young’s modulus was calculated based on UCS measurements and the dynamic Poisson’s ratio was taken. For the fracture toughness, typical values for the five different rock types were chosen. The properties of deeper formations without measurements were derived based on rock type and the properties of shallower formations. In general, for deeper formations, less information was available from close wells and therefore the information was less reliable.
Tensile strength was not considered because of the lack of data. The mechanical parameters as well as the magnitude of the minimum horizontal stress are shown in Figure 4.

**FRACTURING SIMULATIONS**

Fracturing simulations were performed for all four potential target formations with the planar three dimensional fracturing simulator MShale (Meyer, 2011).

For all simulations a binary fracturing fluid was injected at a constant flow rate of 100 l/s. The intermediate viscosity fluid was chosen to ensure sufficient proppant transport (high viscosity needed) and to reduce fracture height growth out of target formations with low stress barriers (low viscosity needed). To prop the fractures open, 16/30 CarboLite proppants were chosen.

**Wabamun Group**

The Wabamun Group is the shallowest unit of all four and is characterized by a relatively low permeability of 2.8 mD; hence, hydraulic stimulation may be needed. However, due to the lack of an upper stress barrier, a controlled fracture development within the target formation can only lead to relatively low maximum fracture half-lengths of about 50 m (Figure 5). If longer half-lengths are anticipated, the fracture grows unimpeded upwards as shown in (Figure 6). Therefore, no hydraulic stimulation treatment should be performed within this formation.

**Nisku Formation**

Hydraulic fracturing may not be the appropriate technology to enhance the permeability of the Nisku Formation because of the high fluid leak-off (and hence significant amounts of fluid needed) due to the relatively high permeability of 9.7 mD, and the unrestricted upward fracture height growth due to the lack of an upper stress barrier. Maximum half-lengths between 100 and 200 m can be achieved depending on the actual stress state (Figure 7 and Figure 8). Hence, the Wabamun Group and the Nisku Formation may be connected leading to a relatively large reservoir. However, long fractures connecting two or more wellbores cannot be created.
A possible stress barrier of the Calmar shales does not lead to sufficient fracture height growth confinement, but longer half-lengths can be achieved.

Cooking Lake Formation
Whether or not the fracture height growth in the Cooking Lake Formation is confined cannot be determined at this stage. Further investigations are needed to clarify the stress gradients within the Cooking Lake and adjacent formations. However, the thick shale formations overlying may have the potential to confine fracture height growth (Figure 9). Figure 10 shows the simulated fracture geometry for the unconfined case.

Due to the relatively large initial permeability (10.4 mD), significant amounts of water would be needed to create new fractures due to the high fluid leak-off. Further investigations are needed to clarify whether or not this formation is suitable for hydraulic stimulation treatments.

Basal Sandstone Unit
The Basal Sandstone Unit is the deepest formation of the four investigated target horizons. Core test from the wells around Edmonton result in an average regional scale permeability of 1.6 mD. This low expected permeability makes stimulation treatments imperative for efficient heat production.

The stress gradient within the sandstone formation is expected to be relatively low. The overlying shale and carbonate formations act as upper fracture height growth barrier due to their larger expected stress gradients. The increasing stress with depth within the underlying Precambrian basement rocks serves as lower stress barrier (Figure 11 and Figure 12). But, since the Basal Sandstone Unit has an expected thickness of only 33 m, the fracture will grow into the basement rocks. Depending on the actual stress within the Basal Sandstone Unit and the actual stress gradient within the Precambrian basement, fractures will grow more or less into the basement rocks (Figure 11 and Figure 12). Fracture growth into the basement can be desired because of the potential increase in the heat exchanger area.
Figure 12: An increased stress confinement leads to the development of fractures with less height.

Figure 13 shows that for the less and better confined cases, the injected slurry volume (fracturing fluid and proppant) and the injected proppant mass needed to create a fracture with 750 mD m conductivity and 300, 400, 500, and 600 m half-length. Depending on the actual fluid leak-off the necessary fluid volume could change significantly.

Figure 14 shows how the fracture area and the average fracture height increase with increasing target fracture half-length.

**Summary of Fracturing Simulations**

For all four target formations the stimulation potential was investigated. Important findings based on potential fracture height growth confinement and important reservoir characteristics are summarized in Table 3. We found that not all of the formations are suitable for massive stimulation treatments. The Wabamun Group should not be hydraulically fractured due to its lack of a sufficient upper stress barrier. For the Nisku and the Cooking Lake formations, a more detailed exploration work is needed to evaluate their confinement potential. While stimulating the Nisku Formation, a hydraulic connection to the Wabamun Group may be developed.

The Basal Sandstone Unit is well confined and has the lowest initial permeability. Therefore, this formation is the best suited for permeability enhancements by conventional gel-proppant fracturing treatments.

**RESERVOIR SIMULATIONS**

Reservoir simulations were performed using the CMG STARS thermal simulator (CMG, 2011). The major performance criteria for the reservoir simulations were a maximum pressure drawdown/buildup of 500 m (5 MPa), a maximum production rate of 50 l/s, a maximum injection rate of 100 l/s, and a re-injection rate of 20°C below the initial reservoir temperature. We investigated how much heat can be extracted from each target formation within these boundary conditions over a period of 1, 5, 10, 20, and 30 years.
The well spacing was set to 400 m and the length of the horizontal well section was 1,000 m for all simulations. The simulations were performed for intact and stimulated reservoir rock and different reservoir development concepts were studied.

Table 3: Stimulation potential for the four investigated formations based on fracture height growth confinement and other characteristics ($k=\text{permeability}$).

<table>
<thead>
<tr>
<th>Formation</th>
<th>Confinement</th>
<th>Characteristics</th>
<th>Conclusions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wabamun</td>
<td>Un-confined</td>
<td>Thickest formation, low init. k</td>
<td>No stimulation suggested</td>
</tr>
<tr>
<td>Nisku</td>
<td>Un-confined</td>
<td>High initial k</td>
<td>Connection to Wabamun</td>
</tr>
<tr>
<td>Cooking Lake</td>
<td>Possibly confined</td>
<td>High initial k</td>
<td>Short or long fractures possible</td>
</tr>
<tr>
<td>Basal Sst.</td>
<td>Confined</td>
<td>Lowest initial k, Thinnest formation</td>
<td>Long fractures, connection to basement</td>
</tr>
</tbody>
</table>

**Intact Reservoir**

For the intact formations reservoir simulations were performed with two vertical wells, two horizontal wells, and three horizontal wells. Figure 15 shows the average total flow rate between injection and production wells for the simulated cases. A relatively poor hydraulic performance can be observed for all four formations in their initial conditions. The maximum flow rate can be achieved with three horizontal wells in the Nisku Formation (24 l/s), which has the highest vertical permeability (1.3 mD) followed by the same well system in the Cooking Lake Formation, which has a lower vertical permeability. It is important to note that the hydraulic performance of a vertical well is best suited in the Cooking Lake Formation because it has the highest horizontal permeability; the lowest initial flow rates can be achieved in the Basal Sandstone Unit due to its low permeabilities.

The flow rate significantly influences the produced heat. This results in relatively low amounts of extracted heat. Figure 16 shows the cumulative produced thermal energy over time. The most heat can be extracted from the Nisku Formation followed by the Cooking Lake Formation and the Basal Sandstone Unit. From the Wabamun Group, the lowest amount of heat can be extracted due to its low permeability and lowest initial reservoir temperature. In all formations, the maximum amount of heat was extracted by three horizontal wells.

**Stimulated Reservoir**

Fractures were implemented as high permeability structures in the single porosity reservoir model. The fracture half-lengths were based on the fracturing simulations: 125 m for Wabamun Group & Nisku Formation; 300 m for Cooking Lake Formation, and; 500 m for the Basal Sandstone Unit. The fractures in the Nisku Formation range up to the Wabamun Group. The Wabamun Group itself was not stimulated.
In cases where one fracture does not intersect all wellbores the injection and production wells were stimulated, otherwise only the injection well was stimulated. An overview of the different fracture and well arrangements is given in Figure 17. Cases 1 and 3 consist of five fractures with a spacing of 200 m. In Case 1, 3, 5, and 7 the fluid flow between the wells is through the fracture(s). In Case 2, 4, 6, and 8 the fluid flows from the fractures through the matrix.

Due to the different permeabilities the flow rates differ in the formations and also significantly differ for different fracture and well arrangements (Figure 18). The maximum flow rate of about 50 l/s was reached by horizontal wells with fluid flow through the fracture (Case 1) for the low permeability Basal sandstone Unit and for the Cooking Lake Formation (Case 1). The same flow rate was achieved by flow through the matrix for the higher permeability Cooking Lake (Cases 2 and 4) and Nisku (Case 2 and 4) formations.

Figure 17: Overview of the 8 different well and fracture alignments as used for the stimulated reservoir simulations.

Figure 18: Average total flow rate for the stimulated reservoir scenarios. The maximum flow rate constraint is 50 l/s.

Figure 19: Cumulative produced thermal energy from stimulated reservoirs for different formations and fracture-well geometries.

Figure 19 shows the resulting cumulative heat produced vs. time. The largest amount of heat was extracted from the Basal sandstone Unit, which had the deepest formation with the highest temperature but also the smallest initial permeability; this was
achieved by applying Case 1 (three horizontal wells and flow through five fractures perpendicular to the wells). The largest amount of heat was extracted from the Cooking Lake and Nisku formations applying Case 2 (three horizontal wells and flow from the three fractures, which are parallel to the wells, through the matrix).

**Summary of Reservoir Simulations**

To summarize the outcome of the reservoir simulations, Table 4 shows the relative thermal performance of the four formations for intact and stimulated rock cases as well as vertical and horizontal wells. In general, horizontal wells outperform vertical wells. All formations show a much better hydraulic performance when stimulated, resulting in much larger amounts of extracted heat. However, the Basal Sandstone Unit in particular needs to be stimulated in order to be productive.

**Table 4: Relative thermal performance and stimulation potential for different formations (1=worst, 4=best).**

<table>
<thead>
<tr>
<th>Formation</th>
<th>Wabamun</th>
<th>Nisku</th>
<th>Cooking Lake</th>
<th>Basal Sst.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stimulation Potential</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
<td>Intact Rock Vert. Wells</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>1</td>
</tr>
<tr>
<td>Intact Rock Hor. Wells</td>
<td>1</td>
<td>4</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>Stimulated Vert. Wells</td>
<td>1</td>
<td>2</td>
<td>4</td>
<td>3</td>
</tr>
<tr>
<td>Stimulated Hor. Wells</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>4</td>
</tr>
</tbody>
</table>

**UTILIZATION OF GEOTHERMAL ENERGY**

The extracted heat can be used for different applications based on the fluid temperature; a summary of this is provided for all four formations in Table 5. Only in the Basal sandstone Unit temperatures are high enough for district heating and refrigeration. The other three formations can be used mainly for agricultural purposes and pre-heating in industrial processes.

84.8% of the energy demand of residential homes in Alberta is for space heating and hot water (NRC, 2010). An average home in Alberta (140 m²) has a space heating load of 80 GJ per year and a water heating load of 40 GJ per year (Hanova et al., 2007). With the generated thermal energy from extracting water at 91°C from the Basal Sandstone Unit and injection at 71°C, up to 1,140 houses can be heated over a period of at least 30 years from a stimulated horizontal three well system with 5 fractures. From the intact reservoir rock, a maximum of about 260 homes can be heated from three horizontal wells or about 18 houses from two vertical wells. To achieve these numbers the system has to run without interruptions.

**Table 5: Potential applications for heat extracted from the four formations (after Lindal, 1973).**

<table>
<thead>
<tr>
<th>Formation</th>
<th>Temperature [°C]</th>
<th>Potential Applications and minimum temperature needed.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basal Sandstone</td>
<td>91 - 71</td>
<td>70°C: Space heating (building and greenhouses), refrigeration.</td>
</tr>
<tr>
<td>Cooking Lake</td>
<td>60 - 40</td>
<td>60°C: Animal husbandry, greenhouses by combined space and hotbed heating.</td>
</tr>
<tr>
<td>Nisku</td>
<td>49 - 29</td>
<td>50°C: Mushroom growing, Balneological baths.</td>
</tr>
<tr>
<td>Wabamun</td>
<td>45 - 25</td>
<td>40°C: Soil warming; 30°C: Swimming pools, biodegradation, fermentations, warm water for year-round mining in cold climates, de-icing; 20°C: Hatching of fish, fish farming.</td>
</tr>
</tbody>
</table>

**ECONOMICS**

The economics of geothermal energy production from intact rock (Figure 20) and stimulated rock (Figure 21) was approximated in terms of $/GJ. Fixed costs for all scenarios were approximated as $2.5 million for pumps and surface installations and $1 million for other operational costs. The cost of one stimulation treatment was assumed as $0.5 million (Tester et al., 2006).

A major cost factor arises from the power needed to produce and inject the fluid which was calculated by multiplying the total required pump power (based on flow rate and well design) with the cost of 0.08 $/kWh.

The other major cost factor was the cost of drilling which was approximated based on experience from hydrothermal wells. Data from Augustine et al. (2006) was fitted by Equation 4 which was used for cost (c [million $]) estimation for the vertical wells based on depth z (km).

\[
c = 0.7108 e^{0.4298z} \tag{4}
\]

Horizontal wells may be up to 3 times more expensive than vertical wells (Helms, 2008); hence, for the cost calculation for horizontal wells and the
cost for the vertical wells were multiplied by a factor of 3.

For intact rock, the most cost effective cases are the Nisku Formation (6.9 $/GJ over 30 years) and the Cooking Lake Formation (8.4 $/GJ over 30 years) which are both accessed with 3 horizontal wells (Figure 20). For all formations, energy extraction is more cost effective when using horizontal wells and when using 3 wells instead of 2.

Energy can be extracted most economically from the shallow formations Nisku/Wabamun and Cooking Lake with three horizontal wells and fractures parallel to the wells. From the Basal Sandstone unit, heat (which can be used for space heating) can be extracted at cost of about 10 $/GJ from three horizontal wells with five perpendicular fractures. Lower costs may be possible if higher flow rates are used and the number of fractures, well spacing, and fracture spacing is optimized.

**REDUCTIONS IN CO$_2$ EMISSIONS AND GAS SAVINGS**

The amount of potential reductions in CO$_2$ emissions and the amount of natural gas that can be substituted by geothermal energy was calculated based on the extracted thermal energy in 30 years. The burning of natural gas emits 15 gCO$_2$/MJ and the total CO$_2$ emissions from the production and burning of natural gas could go up to 31 gCO$_2$/MJ (Howarth et al., 2011). Geothermal energy, on the other hand, emits only 2 to 3 gCO$_2$/MJ (Bartani and Thain, 2002). Therefore, using geothermal energy can reduce CO$_2$ emissions by 12 to 29 gCO$_2$/MJ.

Possible CO$_2$ savings for the most promising simulated cases are shown in Figure 22. For the 3 horizontal well intact rock cases, the highest amount of CO$_2$ can be saved by utilizing the Nisku Formation (24,764 – 59,846 tons). Overall, the stimulated Basal Sandstone Unit leads to the largest reductions in CO$_2$ emissions (49,200 – 118,900 tons). By comparison, the annual greenhouse gas emissions from space heating in the residential sector in Alberta are approximately 6.3 Mt (6,300,000 tons) of CO$_2$ per year (Hanova et al., 2007).

About 27 m$^3$ of natural gas needs to be burned to produce 1 GJ of energy. For the intact rock cases between 22.0E+6 m$^3$ (Wabamun) and 55.7E+06 m$^3$ (Nisku), natural gas can be saved. The gas savings for the intact Cooking Lake Formation is 47.1E+06 m$^3$ and for the intact Basal Sandstone Unit 25.3E+06 m$^3$. If the reservoirs are going to be stimulated, savings are up to 110.7E+06 m$^3$ for the Basal sandstone unit, 108.4E+06 m$^3$ for the Cooking Lake Formation, and 103.1E+06 m$^3$ for the Nisku Formation /Wabamun Group.
Figure 22: Potential CO₂ savings for stimulated (stim.) and intact reservoirs assuming 12 and 29 g CO₂ reductions per GJ. The presented data is from the Scenarios generating the most heat.

CONCLUSIONS & REMARKS
The integrated geological, reservoir, and stimulation modeling approach leads to the following conclusions and remarks:

1. The Wabamun Group is not viable for heat extraction purposes.
2. Stimulation treatments may connect the Nisku Formation and the Wabamun Group.
3. The Cooking Lake Formation is more suitable for geothermal energy extraction than the Wabamun Group and the Nisku Formation.
4. The Basal Sandstone Unit is potentially the most promising EGS reservoir out of the four investigated formations and reservoir stimulation is imperative and possible for this formation. Gel-proppant fracturing could be a suitable stimulation method. The fracture development is most likely well confined by the overlying shale formations. Fracture development into the Precambrian basement is likely and could increase the reservoir volume significantly; however, the data basis for this formation is very poor. Additional investigations are needed to clarify rock properties.
5. For all four formations, stimulation treatments significantly increase the amount of produced heat, horizontal wells outperform vertical wells, and a three-well system is more suitable than a two-well system.
6. In low permeability formations (Basal Sts.) fractures should connect the wells. In higher permeability formations (Cooking Lake, Nisku) fractures should be parallel to the wells.
7. Geothermal energy generation can be economically feasible if the natural gas price increases. Costs range between 6 and 14 $/GJ and can be further reduced by optimization.
8. Up to 1,140 houses can be heated (space and water heating) with geothermal energy from the most promising simulated three-well system.
9. Large amounts of CO₂ emissions can be reduced (up to 0.12 Mt in 30 years) and natural gas can be saved (up to 111E+06 m³ in 30 years) by substituting natural gas with geothermal energy from a three well system in the Basal Sandstone Unit.

REFERENCES


