

# Deep Geothermal Heat Storage Under Oilsands— Can We Use it to Help Oilsands Industry? New EGS Concept Proposed

Jacek Majorowicz<sup>1</sup>, Hannes Hofmann<sup>2</sup>, and Tayfun Babadagli<sup>2</sup>

<sup>1</sup>Department of Physics, University of Alberta, Edmonton, Alberta, Canada

<sup>2</sup>Department of Civil and Environmental Engineering, University of Alberta, Edmonton, Alberta, Canada

## Keywords

*EGS, Geothermal energy potential, Canadian sedimentary basin, Alberta basin, oilsands recovery, EGS model*

## ABSTRACT

The research into a geothermal energy option for a deeper crystalline basement heat source in the Northern Alberta basin as a potential artificially fractured subsurface heat exchanger to deliver heat for oilsands processing and/or deep geothermal energy for heating to offset CO<sub>2</sub> emission is currently underway as part of the University of Alberta Helmholtz-Alberta Initiative (HAI) geothermal energy project. Temperature logging into old Precambrian granites beneath 0.5 km thin sedimentary column in the 2.35 km deep Hunt well near Fort McMurray shows that there is a rather limited amount of heat in granites. It would require drilling some 4-5 km to get to 80-100 °C in Fort McMurray area and 120-150 °C in Peace River area, respectively. This temperature is not sufficient to generate steam for the in-situ recovery of heavy-oil and bitumen but the demand for hot water for surface processing is limited to only 40-70 °C. Our current effort is to generate hot-water through engineered geothermal systems (EGS) for surface processing of bitumen in the Fort McMurray area as an alternative to burning natural gas for this purpose. At the same time, relatively high temperature gradient areas can serve as a heat source for communities. In this paper, we propose a new concept for greening oilsand energy through the new EGS system. This system is planned to deliver heat for the processing of mined oilsands or pre-heating using inclined to horizontal drillholes used to create artificial heat exchange space and use deep underground heat beneath oilsand.

In addition to this, tapping into naturally existing hot aquifers in the hotter Foreland Alberta basin to produce heat/electricity for communities in order to offset the CO<sub>2</sub> emissions from oilsand operations is proposed as another option.

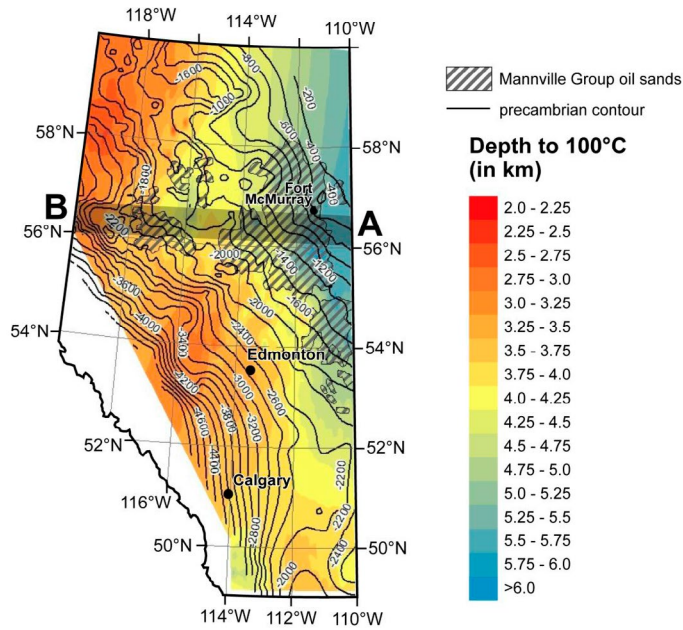
## The Need for a Heat Source in Northern Alberta

Processing of mined oilsands (separation from sand) accounts for around 6% of Canada's natural gas consumption and incurs significant economic costs and environmental impact. This process requires a continuous supply of heated surface water with temperatures around 40-70 °C. The remaining 80% of oilsands reserves are too deep to mine but can be extracted using in-situ techniques such as Steam Assisted Gravity Drainage (SAGD) where steam is injected. This process also requires large quantities of steam to be generated by burning natural gas.

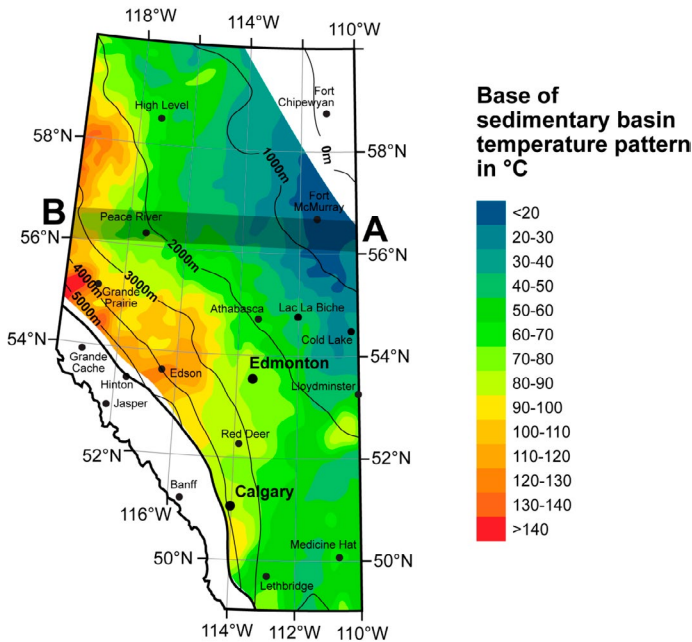
An alternative to burning natural gas could be geothermal heat extracted from the crystalline basement. The primary area of interest is in the Athabasca oilsands where the Western Canadian Sedimentary Basin (WCSB) is relatively thin and the Phanerozoic sedimentary succession thins towards the northeast and sub-crops onto the Canadian Shield. In this area, the Precambrian basement is at a depth of some 0.5 km and is being currently studied by Helmholtz-Alberta Initiative (HAI) scientists through the analysis of geophysical logs, core, and rock chip samples from a deep well drilled into the granitic basement rocks (Majorowicz et al., 2012). A preliminary study (Majorowicz et al., 2012) showed that we would need to drill as deep as 4-7 km into the granites of the Precambrian basement to provide significant amount of heat. This idea is currently under investigation in more details by the same research group of the (HAI), which is a recently established research collaboration between the Helmholtz Association of German Research Centers and the University of Alberta

## Heat Available In and Beneath Sedimentary Basin

Heat naturally stored in the sedimentary basin beneath oilsands is rather low, varying from 13 °C to some 80 °C, and depths to drill to higher temperatures are high (3-5 km to reach 100 °C; Figure 1) as the map of temperature patterns at the base of the Alberta basin shows (Figure 2). Temperatures greater than 100 °C (150 °C max.) are in the deep part of the basin far west and south west of the oilsands accumulations, especially the Athabasca region.



**Figure 1.** Depth to drill to 100 °C vs. depth to Precambrian basement. Profile AB data are discussed later in the paper (map modified from Majorowicz and Weides, 2012). Precambrian basement isopachs and geological pattern (Mannville group oilsands) are shown here modified from Mossop, G., and Shetsen, I. (Eds), 1994.

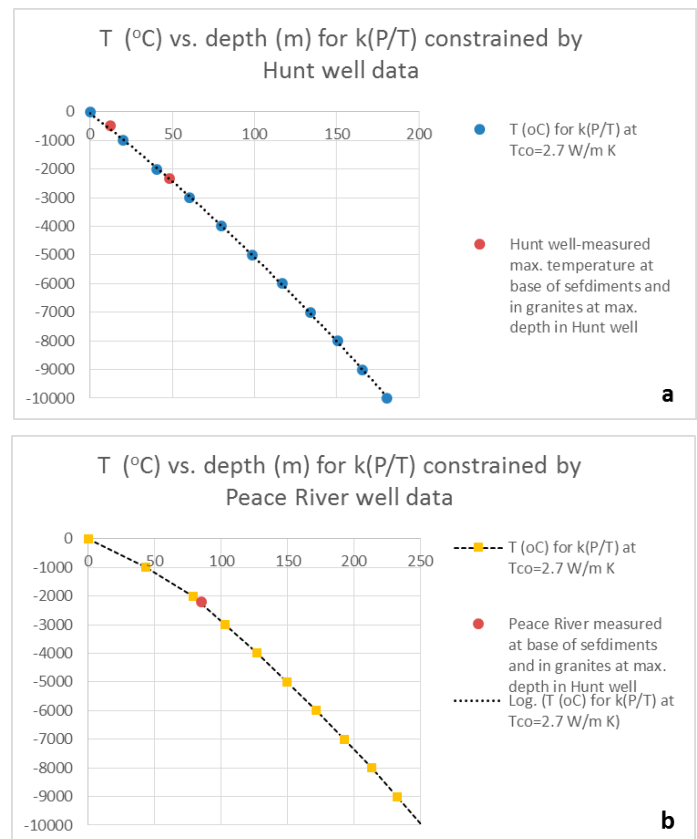


**Figure 2.** Maximum temperatures available at the base of the sedimentary basins fill (top of Precambrian crystalline basement) from measured industrial temperature data (Annual Pool Pressure surveys (APP) temperatures, Drill Stem Test (DST) temperatures and Bottom Hole Temperatures (BHT)), and few precise equilibrium logs like the one in Hunt well (Majorowicz et al., 2012)), and estimated thermal conductivity and heat flow (Majorowicz et al., 2012b and Gray et al., 2012) used for downward extrapolation in case measurements made above.

The estimates of thermal conductivity of the Phanerozoic WCSB fill was described in detail in Majorowicz et al. (2012) and Gray et al. (2012). The observed main trend of thermal conductivity change across the basin in this area is a trend of

increasing thermal conductivity that is approximately parallel to the Phanerozoic isopach. The lower thermal conductivities in the deep basin are the result of a combination of two factors. Firstly, low conductivity shale formations are relatively more abundant in the fore-deep to the SW while sandstones and carbonates are much more abundant in the shallow basin succession. Secondly, many rocks experience decreasing thermal conductivity with increasing temperature; therefore, the deeper parts of the basin experience a stronger “blanketing effect” by low conductivity sediments causing higher gradients to the west. This is well illustrated in Figure 3 which compares these two profiles in temperature in °C vs. Depth (m) for the shallow and deep parts of the basin. The predicted temperatures are well constrained by measurements.

Measured heat generation (HG) values for the sedimentary rocks of the WCSB have been found to be too low (<0.5 mW/m<sup>3</sup>) to significantly affect heat flow; however, they have been taken into



**Figure 3.** (a) Temperature-depth predictions in the Fort McMurray region (Hunt well). The surface heat flow in the well reaching deep into granites beneath Hunt well near Fort McMurray is calculated as a product of geothermal gradient at max. well depth in granites, 21 K/km, measured thermal conductivity TC for this granite, 2.7W/m K corrected for the in situ pressure –temperature conditions (2.5 W/m K), measured mean heat production in granite, 3 μW/m<sup>3</sup>, and heat production of sediments, 0.5-0.7μW/m<sup>3</sup>. Correction for the influence of glacial to interglacial surface temperature change has been applied (Gosnold et al., 2011; Majorowicz et al., 2012b). Predictions for the Peace River area **Figure 3.(b)** are based on measured temperature at Precambrian (Pc) base and HF determined from industrial data, thermal conductivity (net rock+ average measured TC for Alberta sedimentary rocks acc. to Beach et al (1987) and measured heat generation of the basement rocks (Jones and Majorowicz, 1987). In both cases, (a) and (b) predictions are constrained by the measured temperatures in the upper parts of the profiles.

account in this calculation together with measured Precambrian granites HG values (Majorowicz et al., 2012).

## Reliability of the Industrial Temperature Data in the Basin

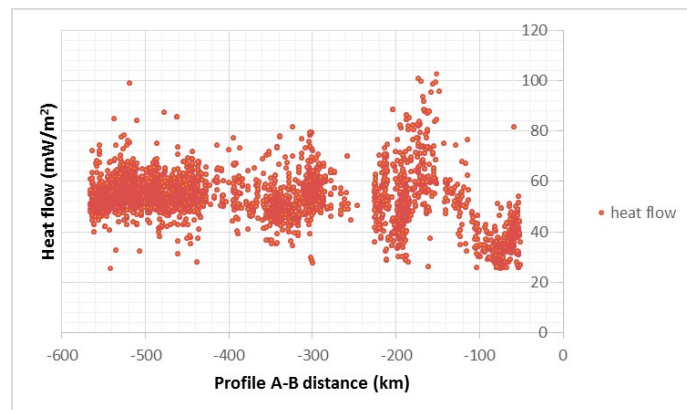
The temperature data we have been using in predicting deep geothermal field within the sedimentary basin are: Annual Pool Pressure surveys (APP), Drill Stem Tests (DST), and Bottom Hole Temperatures (BHT), drill stem test temperatures (DST) and precise equilibrium logs, which are few (Garland and Lennox, 1962; Majorowicz et al., 2012). The systematic errors were identified as a significant overestimation of Alberta industrial well logs from shallow depths (<1000m) before Hackbarth (1978), Majorowicz et al. (1999, 2012), and Gray et al. (2012). These have been filtered out from our data base. This data used to calculate geothermal gradient (Figure 4) still show large noise typical for industrial temperatures from wells despite applying all of the standard corrections (Horner, Harrison SMU, etc.) (Lam et al., 1985).

Tens of thousands of industrial temperature measurements in three independent datasets coupled with 33 TC (Thermal Conductivity) from Alberta wells were used by Beach et al. (1987). This (Figure 5) provides a more accurate prediction of heat flow of the northern Alberta part of the WCSB (Majorowicz et al., 2012, 2012b and Gray et al., 2012). Temperature and heat flow corrections for paleoclimatic influence was applied by Gosnold et al. (2011) and Majorowicz et al. (2010) for the correction meth-

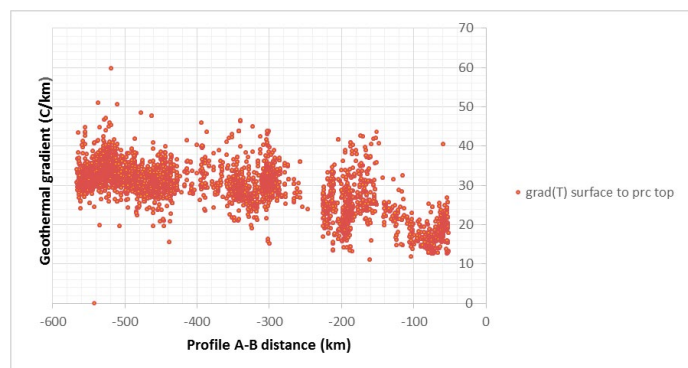
odology. The corrected heat flow profile is shown in Figure 6.

## Geothermal Profile Across the Oilsands Area and Beyond

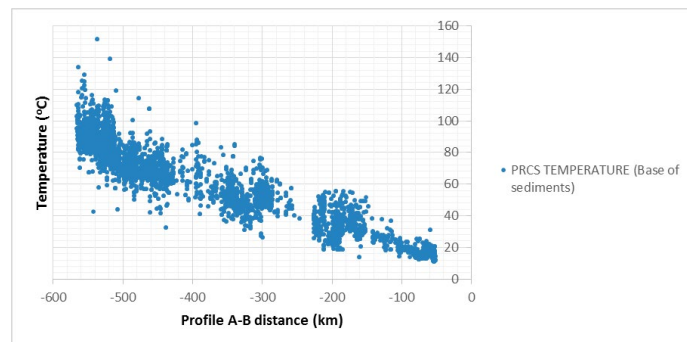
We looked at the temperature at the basin's base (top of Precambrian), geothermal gradient and heat flow along the profile A-B in a wide 100 m band. The profile goes from the shallow part of the basin in the east (0.5 km) in the Fort McMurray area to the deeper 3 km-thick basin west of Peace River. We observed large variability and narrowing the profile width down to 10 km still



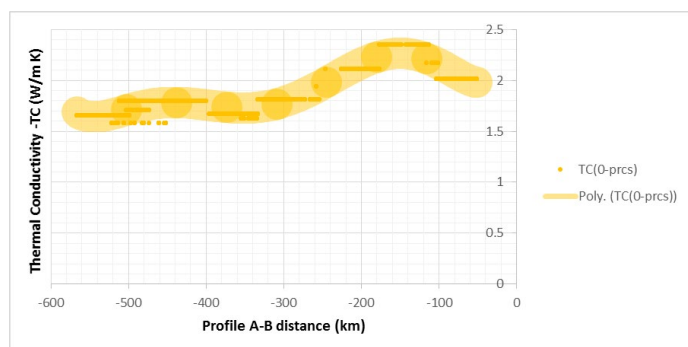
**Figure 6.** Estimated heat flow ( $\text{mW/m}^2$ ) for the wells on the profile A-B (East-West) in the 100 m wide band.



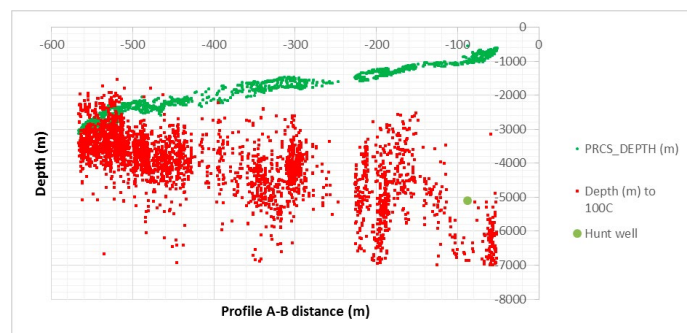
**Figure 4.** Variability of geothermal gradient along the profile A-B (East-West) in the 100 m wide band.



**Figure 7.** Temperature at the base of sediments (Precambrian surface – PRCS) for the wells on the profile A-B (East-West) in the 100 m wide band.



**Figure 5.** Thermal conductivity model for the depth interval between the surface and Precambrian top for the wells on the profile A-B (East-West) in the 100 m wide band.



**Figure 8.** Predicted depth to a temperature of  $100\text{ }^{\circ}\text{C}$  (depth to drill to) for the wells on the profile A-B (East-West) in the 100 m wide band. Precambrian surface top (PRCS) for each well with thermal data is shown. Hunt well prediction of depth to  $100\text{ }^{\circ}\text{C}$  is marked.

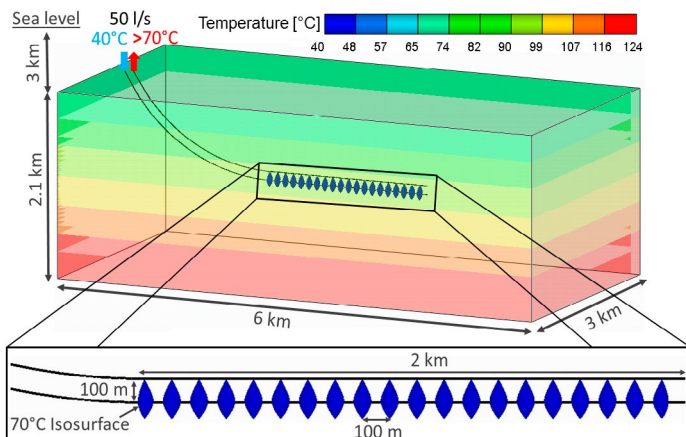
gives high data noise. This is because of the fact that the data has been corrected for return to equilibrium with Horner (Lachenbruch and Brewer, 1959), Harrison (Harrison et al, 1983), SMU (Blackwell and Richards, 2004) corrections. This leaves us with a lot of uncertainty in predicting temperature at depth below the data depth (max. well depth). Therefore, we give the most trust to equilibrium temperature logs in 2.35 km Hunt well and predictions based on other measured parameters like HG (Heat Generation), TC and derived heat flow with depth. However, industrial data give us some important information about where we have high temperatures, and it turns out that these ( $>100\text{ }^{\circ}\text{C}$ ) are all in crystalline rocks below sedimentary succession in the oilsands areas (Figure 7-8). In the Athabasca oilsands, the temperature at the base of sedimentary cover is only  $10\text{-}40\text{ }^{\circ}\text{C}$  (Figure 7).

## Partial Conclusion Derived From Thermal Data

As seen from the above summary, the available basin temperatures are not sufficient to be of much use in the deep part of the basin where SAGD in situ recovery is used. Temperatures greater than  $200\text{ }^{\circ}\text{C}$  is needed for SAGD operations, whereas in the shallower part of the basin, lower temperature water ( $40\text{-}70\text{ }^{\circ}\text{C}$ ) is sufficient for separating oil from sand from mined oilsands at surface facilities (plants). Note, however, that we have enough heat beneath in the granitic rocks of the basement. These needed temperatures come at large drilling depths (some  $100\text{ }^{\circ}\text{C}$  at  $5\text{ km}$  beneath mined Fort McMurray area and  $150\text{ }^{\circ}\text{C}$  at  $5\text{ km}$  beneath SAGD mined oilsands of Peace River ( $200\text{ }^{\circ}\text{C}$  at some  $7\text{ km}$ ) as shown below (Figures. 2-3).

## Proposed EGS System - Model

We propose a new EGS system layout that has never been tested in the field so far to mine the heat of the Precambrian basement below the Fort McMurray oilsands area for oilsands processing purposes. The model is based on recent shale gas exploitation concepts. Long horizontal wells are drilled at the target depth and hydraulic fracture systems are induced at several stages to develop a well distributed fracture network along the well lateral with a relatively large amount of fractures having a



**Figure 9.** Temperature distribution and  $70\text{ }^{\circ}\text{C}$  isosurface for Scenario 7 ( $400\text{ mD m}$  fracture conductivity) after 15 years of operation.

relatively low fracture conductivity (Figure 9).

In this system the injection well is placed below the production well. It is expected that with this configuration, gravitational forces will help to increase the residence time of the water in the fracture system and prevent early thermal breakthrough.

The system has the advantage that a hydraulic connection between the two wells can be achieved more easily as compared with longer well spacing configurations. However, the creation of single high conductivity fractures has to be avoided in order to prevent thermal breakthrough.

## Reservoir Simulations - Methodology

A simulation study of different EGS well triplets in the Precambrian basement in Alberta was presented earlier by Hofmann et al. (2012). In this study, the thermal and hydraulic performance of three parallel wells was evaluated for different hydraulic fracture systems and well configurations. A similar study was conducted for sedimentary formations in the central part of the WCSB (Hofmann et al., 2013). In the present study, we considered a different configuration and tested the hydraulic and thermal performance of a well doublet in the Precambrian basement with one well above the other and relatively small well spacing of  $100\text{ m}$ . The thermal and hydraulic reservoir properties we used for our simulations are given in Hofmann et al. (2012).

Coupled single phase (water) fluid flow and heat transport were modeled using the commercial finite difference reservoir simulator CMG STARS (CMG, 2011). Fluid viscosity and density change depending on pressure and temperature. Fractures are represented using a single porosity approach. High conductivity fracture cells ( $100\text{ mDm} - 800\text{ mDm}$ ) are located within low permeability ( $0.0005\text{ mD}$ ) rock matrix cells. In the vicinity of fractures and wells the grid is locally refined (Figure 9).

We simulated a well doublet with a horizontal injection well (at  $4.1\text{ km}$  depth) below a horizontal production well (at  $4.0\text{ km}$  depth). The horizontal section of both wells is a  $2\text{ km}$  long open hole. Fractures are perpendicular to the wells. We considered eight different cases. Fracture spacing, number of fractures, fracture conductivity, temperature gradient and temperature at  $4\text{ km}$  depth for these Scenarios are given in Table 1.

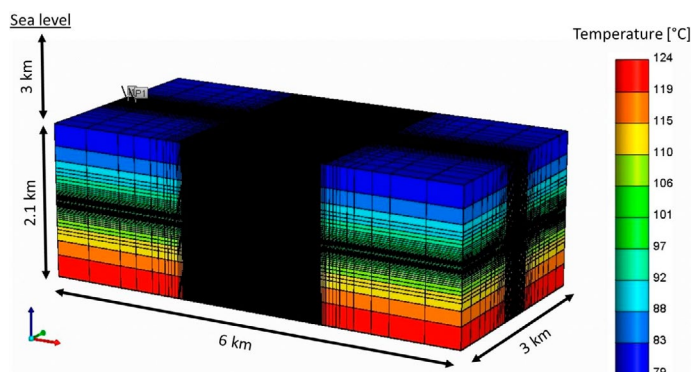
The number of fractures and fracture conductivities were

**Table 1.** Summary of Thermal and Fracture Properties of the Eight Scenarios.

Scenario	1	2	3	4	5	6	7	8
Temperature Gradient [ $^{\circ}\text{C}/\text{km}$ ]	20	20	20	20	25	25	25	25
Temperature at $4\text{ km}$ [ $^{\circ}\text{C}$ ]	80	80	80	80	100	100	100	100
Fracture Spacing	25	50	100	200	25	50	100	200
Number of Fractures [-]	80	40	20	10	80	40	20	10
Fracture Conductivity [ $\text{mD m}$ ]	100	200	400	800	100	200	400	800

changed in such a way that the overall reservoir transmissivity was the same for all scenarios. For four scenarios, we assumed a low thermal gradient of  $20\text{ }^{\circ}\text{C}/\text{km}$  as observed in the Hunt Well near Ft. McMurray. For the other four scenarios, a temperature gradient of  $25\text{ }^{\circ}\text{C}/\text{km}$  was used that can be found in other parts of NE Alberta. Fracture dimensions are the same for all simulations

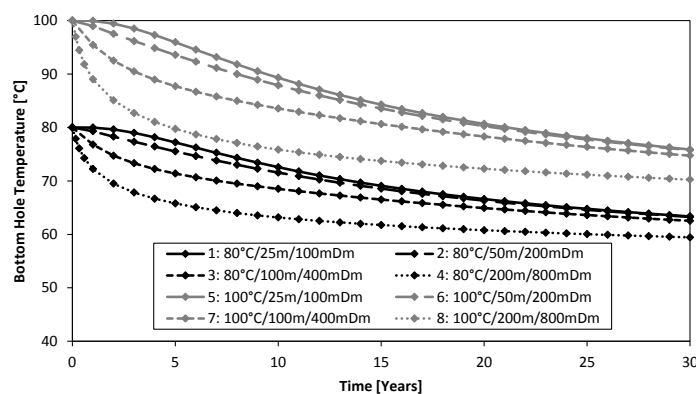
(rectangular shape, 400 m high and 800 m long). Injection and production rates are 50 l/s. The re-injection temperature is 40 °C. The simulations are performed for a period of 30 years. Overall, model dimensions are 6,000 m (length) x 3,000 m (width) x 2,100 m (height). The top of the model domain is located at 3 km depth. The discretized 3D reservoir model is shown in Figure 10.



**Figure 10.** 3D Reservoir model showing the initial temperature distribution for a geothermal gradient of 20 °C/km.

## Results

For the eight different scenarios the bottom hole temperature (Figure 11) and the cumulative produced heat (Figure 12) are shown for a period of 30 years. What is meant by cumulative produced heat is the net heat produced, which is the difference between the cumulative heat produced in the production well and the cumulative heat injected in the injection well.

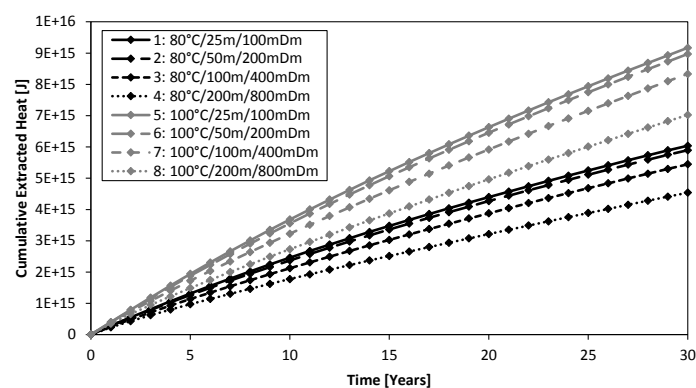


**Figure 11.** Temperature development over time for different initial temperatures, well spacing and fracture conductivities.

As expected, the lowest temperature drawdown occurs in Scenarios 1 and 5 with the lowest fracture conductivity and the largest number of fractures. However, the temperature drawdown after 30 years of production is relatively similar for fracture spacings of or below 100 m. For all scenarios the temperature after 30 years is still sufficient to be used for oilsands processing purposes.

The largest amount of heat can be extracted from the scenario with the lowest fracture conductivity and the largest number of fractures. Between 25 and 50 m fracture spacing the difference

is relatively low ( $1.99E14$  J for 100°C initial temperature). But, for fracture spacing between 25 and 100 m, significantly less heat can be extracted from the subsurface ( $8.37E14$  J for 100 °C initial temperature). Therefore, it is obvious that very dense, evenly distributed and complex fracture networks need to be generated over the whole length of the horizontal well section to improve heat production. The largest simulated cumulative extracted heat is  $9.17E15$  Joules after 30 years for the case of the initial temperature of 100 °C. This is comparable to the heat extracted from a three well system of parallel wells which could produce between  $9.6E15$  and  $14.4E15$  Joules in 30 years at a slightly higher total flow rate of approximately 60 l/s (Hofmann et al., 2012). With an 80 °C initial temperature, up to  $6.04E15$  Joules of heat can be extracted with a fracture spacing of 25 m. The productivity index for all scenarios lies between 13 and 14 l/s/MPa, which we consider to be sufficient for economic heat production.



**Figure 12.** Cumulative extracted heat for different initial temperatures/well spacing/fracture conductivities.

The proposed idea of a closely spaced (100 m) horizontal well doublet with a long lateral (2 km) has a large potential if a dense (fracture spacing below 100 m) and well distributed (over the whole lateral) fracture network can be created. Further research is needed on how to create such a fracture network.

## Conclusions

- Recent results from a 2.3 km deep temperature log in northern Alberta, Canada and thousands of industrial temperature, thermal conductivity, and heat generation records acquired as part of the University of Alberta Helmholtz-Alberta Initiative (HAI) geothermal energy project shows that there is a significant amount of heat under the oilsands.
- The configuration of the basin and thermal resource is such that there is not enough heat for feasible geothermal energy projects to help oilsands industry in their in situ oil recovery projects, unless deep 7-8 km wells are drilled deep into the Precambrian granites under some 2 km sedimentary thermal blanket in the Peace River oilsands area.
- In the shallow basin (0.5km) near Fort McMurray there is not enough heat to make it feasible to use it economically and commercially for heating water used in separating mined oil from sand (40-70 °C would do). We can, however,

produce such temperature water circulating it through artificially created underground heat exchanger in granites at some 4-5 km below the surface.

- We propose a doublet well system that deviate from vertical and run horizontally 2 km at some 4 km depth closely spaced (100-200m) above each other. A dense and well distributed fracture network is intersecting the wells perpendicular.
- The system gives comparable amounts of output heat as compared with largely spaced deviated wells connected through some major fractures. The system is sustainable for some 30 years before significant cooling. It may have advantages as drilling 2 wells could be enough, fractures do not need to be larger than 100-200 m and a hydraulic connection between injector and producer can be achieved more easily.

## Acknowledgments

UofA-GFZ team has been working on the project under Helmholtz Alberta Initiative HAI project (Theme 4). The leadership of Prof. Martyn Unsworth (HAI 4 Leader) is greatly appreciated. We thank CMG for providing the reservoir simulator for research purposes.

## References

- Beach, R. D.W., Jones, F.W., and Majorowicz, J.A. 1987. Heat Flow and Heat Generation Estimates for the Churchill Basement of the Western Canadian Basin in Alberta, Canada, *Geothermics*, 16-1, 1-16.
- Blackwell, D. D., and Richards, M. 2004. Calibration of the AAPG geothermal survey of North America BHT data base, AAPG Convention, 2004 poster online: <http://smu.edu/geothermal/bht/aapg04%20blackwell%20and%20richards.pdf>.
- Computer Modeling Group Ltd. 2011. "User's Guide STARS Advanced Process and Thermal Reservoir Simulator".
- Garland, G. D., and Lennox, D. H. 1962. Heat flow in Western Canada, *Geophys. J. R. Astr. Soc.*, 6: 245-262.
- Gosnold, W., Majorowicz, J. A., Klenner, R., and Hauk, S. 2011. Implications of Post-Glacial Warming for Northern Hemisphere Heat Flow, *GRC Transactions*, 35: 795-800.
- Gray, A., Majorowicz, J., and Unsworth, M. 2012. Investigation of the geothermal state of sedimentary basins using oil industry thermal data: Case study from Northern Alberta exhibiting the need to systematically remove biased data. *IOP J.Geoph. Eng.*, JGE/428217/PAP/128312.
- Hackbarth, D. A. 1978. Groundwater temperatures in the Athabasca oil sands area, Alberta, *Canadian Journal of Earth Science*, 15, 1689-1700.
- Harrison, W.E., Luza, K.V., Prater, M.L., and Chueng, P.K. 1983. Geothermal resource assessment of Oklahoma. Special Publication 83-1, Oklahoma Geological Survey.
- Hofmann, H., Weides, S., Babadagli, T., Zimmermann, G., Moeck, I., Majorowicz, J., Unsworth, M. 2013. Integrated Reservoir Modeling for Enhanced Geothermal Energy Systems in Central Alberta, Canada. *Proceedings, Thirty-Eight Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, February 11-13, 2013.
- Hofmann, H., Babadagli, T., Zimmermann, G., 2012. Hydraulic Fracturing Scenarios for Low Temperature EGS Heat Generation from the Precambrian Basement in Northern Alberta. *GRC Transactions*, Vol. 36.
- Jones, F. W., and Majorowicz, J. A. 1987. Regional trends in radiogenic heat generation in the Precambrian basement of the Western Canadian Basin, *Geophysics Resource Letters*, 14, 268-271.
- Lachenbruch, A., and Brewer, M. 1959. Dissipation of temperature effect of drilling a well in Arctic Alaska *USGS Bull.* 10834, 73-109.
- Lam, H, Jones, F, and Majorowicz, J. (1985). A statistical analysis of bottom-hole temperature data in southern Alberta: *Geophysics*, v. 50, no. 4, p. 677-684.
- Majorowicz, J.A., and Jessop, A. M. (1981). Regional heat flow patterns in the Western Canada Sedimentary Basin, *Tectonophysics*, 74: 209-238.
- Majorowicz, J., and Wybraniec, S. 2010. New terrestrial heat flow map of Europe after Regional paleoclimatic correction application, *International Journal of Earth Sciences (Geol. Rundsch.)*, DOI 10.1007/s00531-010-0526-1.
- Majorowicz, J.A., Garven, G., Jessop, A., and Jessop, C. 1999. Present heat flow along a profile across the Western Canada Sedimentary Basin: The extent of hydrodynamic influence, in: A. Forster, and D. Merriam, eds., *Geothermics in Basin Analysis, Computer Applications in the Earth Sciences*, 61-80, Kluwer Academic / Plenum Publishers.
- Majorowicz, J., Unsworth, M., Chacko, T., Gray, A., Heaman, L., Potter, D., Schmitt, D., and Babadagli, T. 2012. Geothermal energy as a source of heat for oil sands processing in Northern Alberta, Canada, in: *Heavy Oil/Bitumen Petroleum Systems in Alberta and Beyond*, co-edited by F. J. Hein, D. Leckie, J. Suter and S. Larter, AAPG Mem.
- Majorowicz, J., Gosnold, W., Gray, A., Safanda, J., Klenner, R., and Unsworth, M. 2012b. Implications of post-glacial warming for northern Alberta heat flow, correcting for the underestimate of the geothermal potential *GRC Transactions*, 36: 693-698.
- Majorowicz, J., and Weides, S. 2012. Is it feasible to use Engineered Geothermal Systems to produce electrical energy in Alberta basin? *Can GRC Rev.*, 3: 2-3.
- Mossop, G., and Shetsen, I., (Eds). 1994. Geological atlas of the Western Canada Sedimentary Basin; Canadian Society of Petroleum Geologists and Alberta Research Council, Special Report 4, URL: [http://www.ags.gov.ab.ca/publications/wcsb\\_atlas/atlas.html](http://www.ags.gov.ab.ca/publications/wcsb_atlas/atlas.html).