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Geomechanical and Thermal Reservoir Simulation Demonstrates SAGD Enhancement Due to Shear Dilation

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Abstract

A novel numerical analysis is described, in which the steam-assisted gravity drainage (SAGD) recovery process in bituminous oil sand is studied. A geomechanical/reservoir simulator was modified to incorporate the absolute permeability increases resulting from the progressive shear dilation of oil sands. The objective was to obtain a realistic prediction of shear dilation, as the oil sands approached failure and beyond, and the concomitant increases in permeability. Changes in the *in situ* stresses that caused this dilation were due to the combined effects of reduced effective stress with high-pressure steam injection, and increased deviatoric stress with thermal expansion under lateral confinement. The resultant volumetric strains were used to modify the absolute permeability characteristics of the oil sands as the SAGD process progressed. The spatial and temporal growth of enhanced permeability zones resulted in an accelerated steam chamber growth.

The relationship between volumetric strains and absolute permeability changes was obtained from existing laboratory data on quality specimens of non-bituminous Athabasca oil sands. The source sample was obtained from an outcropping of the McMurray Formation, thus avoiding most of the sample disturbance associated with unconsolidated core obtained conventionally. Under triaxial loading, the resultant volumetric strains increased absolute permeabilities by a factor of 4 to 6.

The analysis is innovative in that the model used an effective stress approach, and used the volumetric strains to modify absolute permeabilities. Thus, the encroaching SAGD steam chamber was found to modify the stress regime, which in turn modified the permeabilities within the reservoir. Geomechanical enhancement of the SAGD process was found to be a significant beneficial effect, and would be increased by operating the SAGD process at higher injection pressures.

Introduction

Conventional reservoir simulations of thermal recovery processes in heavy oil and bituminous oil sands do not explicitly incorporate geomechanics. However, they implicitly include geomechanics since input permeabilities are air permeabilities obtained from core plugs. Due to the unconsolidated structure of these sands, core plugs are highly disturbed[1]. Porosities are typically 120% to 130% of the *in situ* porosities, as determined by petrophysical logging and other means. Specimens tested at overburden stress indicate that this disturbance results in permeabilities that are four times higher than *in situ* liquid permeabilities, on average.

Fortuitously, these inflated permeabilities are comparable to those *in situ*, once the oil sand reservoirs have been disturbed. This is due to the shearing and dilation resulting from stresses altered by the recovery process itself. This is evident from history matches of SAGD projects, such as the UTF[2], which used permeabilities obtained conventionally. Note that the limited number of operating SAGD projects have all been operated at relatively high injection pressures, relative to the reservoir depth, which result in low effective stresses. Therefore, while the implicit use of geomechanics, through the use of high absolute permeabilities, does work for the existing SAGD projects, this methodology cannot necessarily be extrapolated to other reservoirs with different operating conditions.

Although history matches and predictions have been successfully conducted without geomechanics, these have been done without a complete accounting of the underlying physics. This is acceptable practice if simulating reservoirs and operating conditions comparable to those of current successful SAGD projects. However, a more rigorous approach was taken in this study, in which the geomechanics of the SAGD process were explicitly included in a combined geomechanics and reservoir simulation.

When geomechanics are considered, absolute permeability in an oil sands reservoir is far from being a fixed property. Thus, the effects of the changing reservoir pressures and temperatures on the geomechanical behaviour of the reservoir were calculated, and in turn, these were used to modify the reservoir parameters.

Laboratory Evidence of Shear-Enhancement of Absolute Permeability

"Absolute" Permeability. The term "absolute permeability" is a misnomer for unconsolidated formations such as oil sands. Permeability is a physical property of a rock and is largely a function of the connected porosity, and the connectivity. For almost all rocks, this physical attribute remains constant, irrespective of the pore fluids. However, oil sands can undergo large increases in porosity, both *in situ* and in the laboratory. As such, the permeability for any given core plug is also a function of its varying porosity, and the term "absolute" becomes relative to the current porosity.

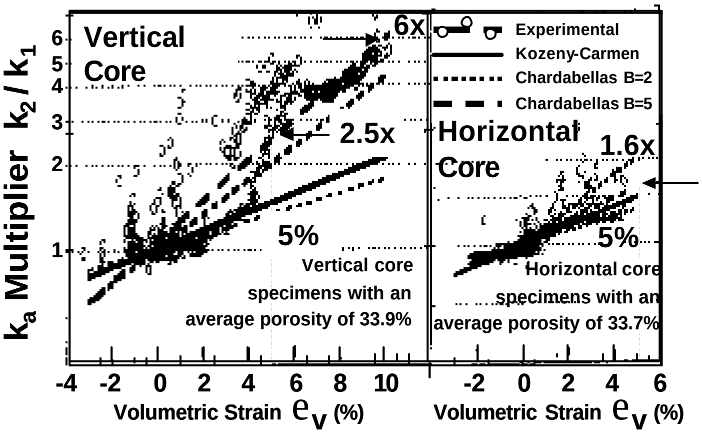
While this behaviour has been qualitatively recognized, a quantitative assessment of this behaviour has been impeded because of the lack of undisturbed oil sands specimens. Currently, the best absolute permeability data for undisturbed oil sand is available from the University of Alberta, as provided in Touhidi-Baghini (1998)[3] and Touhidi-Baghini and Scott (1998)[4].

Increases in Absolute Permeability. Touhidi-Baghini's laboratory work was on specimens from undisturbed, bitumen-free oil sands, obtained from an outcrop of the McMurray Formation. Horizontal and vertical specimens were cored from the outcrop samples in the laboratory. In general, initial porosities were in the order of 34%, and initial absolute permeabilities were 1 to 2 Darcies, with horizontal specimens having the higher permeabilities. In contrast, most numerical simulations for the same formation have only been successful when using permeabilities of 5 to 10 Darcies.

Figure 1 shows the results of a number of permeability tests conducted while the specimens were loaded under triaxial conditions, in which the axial load was increased while the specimens were under a confining stress. On the left is the plot for specimens cored in a vertical orientation; on the right, one for specimens cored horizontally. The vertical axis is the absolute permeability multiplier, relative to the initial absolute permeability at the beginning of the test, before the axial load was increased. The horizontal axis is volumetric strain or dilation, measured as a percentage of the original sample size.

At a volumetric strain of 5%, there are increases in absolute permeability by a factor of 2.5 for the vertical specimens, and by a factor of 1.6 for the horizontal specimens. At a higher volumetric strain of 10%, the vertical specimens have an increase in absolute permeability by a factor of six.

The implications of this plot are very significant. Not only is there an increase in absolute permeability with dilation; it is almost an order of magnitude. This is not discussed nor accounted for in conventional thermal reservoir simulations. In addition, some dilation and permeability enhancement are occurring from the onset of shearing, before failure occurs.



Touhidi-Baghini (1998) Fig.8.21 & 8.22 (mod.)

Figure 1 Absolute Permeability Increase with Dilation

SAGD Process

Steam is injected into a horizontal well within the bitumen-rich oil sands reservoir at a constant pressure (Figure 2). Steam migrates to the perimeter as condensation occurs on the colder bitumen-rich oil sands at the perimeter of the steam chamber. As the steam condenses, the latent heat released heats the bitumen until its viscosity is reduced sufficiently to flow. The hot water and bitumen flow to the horizontal producer well by gravity alone. Production rates are automatically throttled to prevent steam production, i.e. under "steam trap" control. As a result, steam injection rates are determined by the rate at which the steam condenses under the constant pressure criterion.

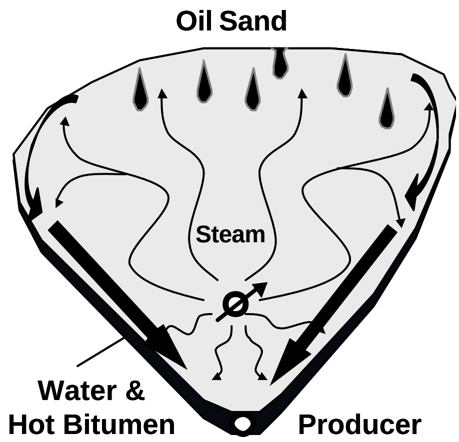


Figure 2 Schematic of the SAGD Process

SAGD-Induced Stress and Permeability Changes

The injection of hot, high-pressured steam into the oil sands during the SAGD process induces stress changes, and these cause increases in permeability. There are three driving mechanisms for the stress changes.

Reduced Effective Stress. The high steam pressures reduce the effective stresses within the reservoir. "Effective" stresses are that portion of the total stresses, such as the overburden stress, that is supported by the sand matrix, with the remainder being supported by the pore fluid pressure. These high steam pressures not only reduce the effective stresses within the depleted steam chamber; they also reduce the effective stresses in the colder zones ahead of the steam chamber. Pressures are conducted through the cold oil sands by the effective mobility of the water phase, especially once shear dilation has occurred: the resultant increase in porosity, and therefore water saturation, amplifies the initial low fluid mobility. Stringers of lower bitumen saturation, within the bitumen-rich oil sands reservoir, also act as pressure conduits.

By reducing the effective stresses, the strength and stiffness of the oil sands are reduced. Given the anisotropic stress state in the reservoir, this will result in the shear failure of the oil sands at sufficiently high injection pressures.

Constrained vs. Unconstrained Thermal Expansion. The high temperature of the injected steam raises the temperature of the sand within the steam chamber. The thermal expansion of this zone is laterally constrained, but vertical expansion is possible for shallower deposits. With increased steam chamber volume, horizontal stresses accumulate much faster than the vertical stress above the steam chamber because the overburden can be displaced upwards. Additionally, due to the elongated shape of the steam chamber at the onset of steaming, stresses parallel to the horizontal well pairs increase substantially, as compared to the transverse horizontal and vertical directions. This increases the anisotropic stress state in the reservoir, thereby increasing the shear stresses, which can contribute to shear failure of the oil sands.

Thermal Jacking. The thermal expansion of the oil sands within the ever-increasing steam chamber will result in the vertical displacement of the overburden. The steam chamber acts as a thermal "jack", progressively displacing the overburden upwards. This effect is greatest when the steam chamber is large in volume, since a small steam chamber would be relatively confined so thermal expansion would result in an increase in isotropic stress. While the volume of the steam chamber increases, the vertical stresses through the steam chamber will increase because the expanding sands will also support a percentage of the overburden above the cold oil sands on either side of the steam chamber. The degree to which this occurs is partially a function of the shear stiffness of the overburden.

As the steam chamber takes up more vertical stress, the colder oil sands on the shoulders of the steam chamber will be stress-relieved, i.e., subjected to less and less vertical stress. For shallow to medium-depth reservoirs, the vertical stress is the minimum stress in the Athabasca oil sands. The reduction of the vertical stress within the cold oil sands outside the steam chamber reduces the minimum stress even further. This both reduces the minimum effective stress, and therefore the strength of the oil sands, and increases the anisotropic stress state in the reservoir. Both these effects can result in shear failure ahead of the steam chamber. This effect would be even greater between well pairs within a steaming pattern.

Shear-Induced Dilation and Enhanced Permeability. The significance of shearing is that it causes dilation before, during, and after shear failure. This dilation is caused by sand grain rotation and displacement, resulting in a permanent disruption of the sand structure. This increases the porosity of the oil sands, which increases the absolute permeability. More significantly, this relatively small increase in porosity results in an increase in the water phase. This allows the fluids to mobilize, resulting in the displacement of bitumen by steam.

Laboratory tests on high-quality specimens of bitumen-rich oil sands demonstrate that, at cold virgin reservoir temperatures (8°C), the dilation of oil sands under triaxial loading results in higher porosities and an influx of water[5]. This increased the effective mobility of the water phase by three orders of magnitude over the course of the tests. With bitumen viscosities of $5 \cdot 10^6$ cP in the cold virgin reservoir, the bitumen is essentially a solid. Therefore, the enhanced fluid mobility due to dilation allows for the influx of warm fluids and the enhancement of the SAGD process.

Field Evidence of Shearing and Dilation

Field evidence of shearing and dilation of oil sands due to the SAGD process are rare. Most projects are instrumented to obtain temperatures, and sometimes pressures, for monitoring the encroaching SAGD steam chamber. These data are used to calibrate the thermal simulation model history match in order to obtain a better model for predicting behaviour. Monitoring displacements, both vertically and laterally, is rarely done since conventional thermal simulations cannot use the data.

An exception was the AOSTRA UTF project (now Devon UTF). The laboratory-scale Phase A pilot project, consisting of three well pairs with 55m completions at 25m spacing, was extensively monitored for pressure, temperature, lateral displacement, and vertical displacement within the reservoir. The SAGD steam chamber was seen to progressively displace the formation outwards, with strains of 0.3%, in response to thermal expansion and dilation within the expanding steam chamber[6]. Furthermore, vertical strains in the order of 4% confirmed that the oil sands were expanding within the steam chamber, with compression above. However, as these extensometers recorded displacements over 3m or 5m intervals, they could only provide an average vertical strain. More variance in strains would be expected, i.e. higher strains and lower strains, if measured over smaller intervals.

To that end, the design of the UTF Phase B commercial pilot included a comprehensive monitoring program to compliment the Phase A monitoring. Phase B had three well pairs with 500m completions at a 70m spacing. The monitoring included a new magnetic extensometer, consisting of ceramic magnets on non-magnetic inconel casing. This provided a means of monitoring displacements throughout the reservoir, the underburden, and the overburden.

Displacements were read periodically from surface, from which strains could be determined.

Preliminary results were encouraging[7], with an expansion of 55mm over the 24m of pay over seven months of heating. While this was only a 0.2% strain, it should be noted that this occurred at the onset of steaming when the steam chamber was extremely small, and that at this well's location, it was between well pairs, i.e. 35m away from the nearest horizontal well pair. No temperature change was recorded at this well over these seven months: the dilation was occurring in the cold oil sands.

Furthermore, the displacement at surface was 50mm, indicating that there was almost no attenuation of the reservoir displacements through the overburden. This would indicate that the reservoir displacements of 55mm were extensive, occurring throughout the pay zone, thereby lifting the overburden uniformly. From this uniformity of dilation, one would infer increased water saturations and enhanced water mobility throughout the predominantly cold reservoir.

Pressure measurements taken within the Phase A pilot clearly demonstrate that pressures are being elevated to near steam pressures far in advance of the steam chamber[8]. Conventional numerical simulators, without considering geomechanics, fail to predict this observed behaviour. These elevated pressures reduce the effective stresses within the cold oil sands, which enhances shearing.

Geomechanical and Reservoir Simulator

A geomechanical and reservoir simulation of the SAGD process was performed, using the GEOSIM program[9]. For every timestep, the geomechanical stress-strain analysis and the thermal reservoir analysis were done independently, and the results used to modify reservoir parameters for the next timestep. In this way, it was feasible to incorporate the absolute permeability increases resulting from the progressive shear dilation of oil sands.

The reservoir model is a full-featured thermal simulator including steam and four-component compositional PVT. The stress-strain model (FEM3D) is a poroelastic and thermoelastic finite element code, which treats elasticity and plasticity. The simulation was run using the hyperbolic model for the pre-failure elastic analysis, with a Mohr-Coulomb failure criterion with nonlinear friction.

Modelling Dilation in FEM3D. Stress-ratio-induced dilation and shear-induced dilation were added to the hyperbolic constitutive model. The overall change in volumes during shear loading is comprised of an elastic component, $\Delta\varepsilon_v^{\,e}$, and a plastic component, $\Delta\varepsilon_v^{\,d}$. The elastic component is due to a change in the mean effective stress, σ_m', and the plastic portion is due to a change in the applied shear stress. In dense sands, the shear strain causes expansion (dilation), while in loose sands, shear strain results in compression.

Stress-ratio-induced dilation. The method for stress-ratio-induced dilation is taken directly from Rowe's dilation theory[10]. The dilation model is based on two equations:

$$b = 45 + {f^*}/{2} \quad \text{..} [1]$$

$$\tan^2 b = \frac{s_1'}{s_3'\left(1+\dfrac{\Delta e_v}{\Delta e_1}\right)} \quad \text{...................................} [2]$$

where, ϕ^* is ϕ_{cv} for loose sands and ϕ_μ (grain-to-grain friction angle) for dense sands, σ_1' is the maximum principal effective stress, σ_3' is the minimum principal effective stress, $\Delta\varepsilon_v$ is the incremental volumetric strain and $\Delta\varepsilon_1$ is the incremental maximum principal strain. The typical behaviour for dense sand is shown in Figure 3:

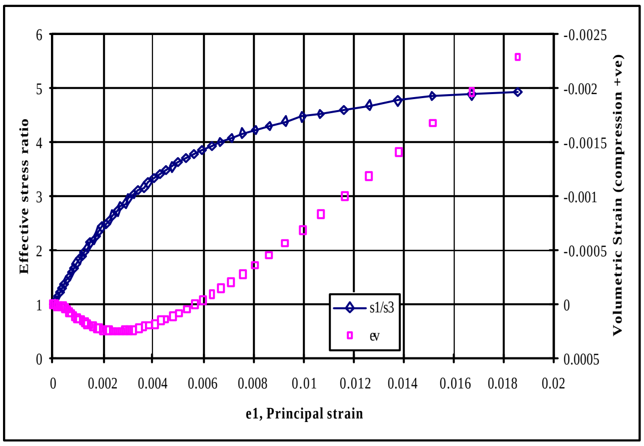


Figure 3. Stress-ratio induced dilation of a dense sand

SAGD Simulation with Geomechanics

A simulation of a SAGD process was conducted using the geomechanical and thermal reservoir simulator. Because of the complexity of the steam-assisted gravity drainage (SAGD) process, only a single well pair was simulated. Permeability enhancement was described by:

$$\ln\frac{k_2}{k_1} = C_{nl} e_v \quad \text{..} [3]$$

where k_2 is the current absolute permeability, k_1 is the original absolute permeability, C_{nl} is a proportionality constant, and ε_v is the volumetric strain. The Touhidi-Baghini data provided C_{nl} = 17.48 for vertical core specimens. As an example, with an initial absolute permeability of 1778 mD, this would provide a permeability of 6000 mD at a volumetric strain of 10%.

The *in situ* stresses were arbitrarily assumed to be orthotropic, with a vertical stress gradient of 22 kPa/m and a uniform horizontal stress gradient of 19 kPa/m. The minimum stress at the depth at the bottom of the grid at 390m was 7410 kPa. This stress state is conservative for the Athabasca oil sands as it is a tectonically affected region, with the major stress expected to be a horizontal stress.

Three steam injection pressures were examined: a base case of 3950 kPa with uniform geology, a high pressure case at 6900 kPa, and a case at 3950 kPa with mudstone stringers within the reservoir. The results are shown in Figure 4. Here, the advantages of operating at a higher injection pressure are obvious, as seen in the solid black lines. Rates are higher, and recoveries occur sooner when compared with the base case, shown as the red dashed lines. The mudstone barriers delay recovery, but do not prevent it, as seen in the dotted blue lines. For the base case, acceptable steam oil ratios (SOR) of 2.6 were obtained by the end of the most productive period, with an ultimate SOR of 3.0 after 10 years.

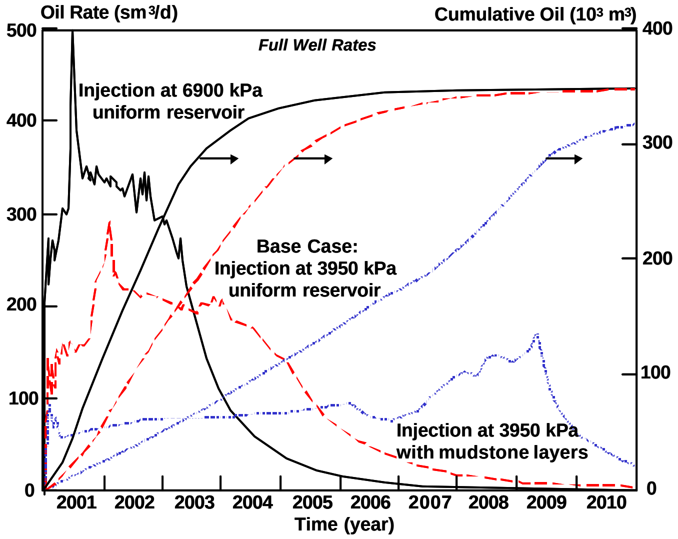


Figure 4. Oil Production

With the injection pressure of 3950 to 6900 kPa, the oil sands reservoir has not failed in shear. Instead, the oil sands are in the process of shearing but are below failure. This means that the permeabilities have not yet achieved their full potential, but instead are on the left hand side of the data shown in Figure 1. At higher injection pressures, the effect of geomechanics would be increased. This simulation, however, does demonstrate that there are benefits of geomechanics even below an injection pressure that would result in shear failure.

Figure 5 shows the permeability multipliers for the base case after injecting steam for 6 months. A half element of symmetry has been used, with the two horizontal wells located at the bottom left, and 1m by 1m gridblocks. The formation has experienced volumetric strain at and above the wells. The associated increase in transmissibility (i.e. permeability) due to shearing is a factor of 2.5 around the wells, and a factor of 1.6 above them. In time, most of the reservoir achieves a transmissibility multiplier of 1.5 to 2.0, with the higher values being at the horizontal wells.

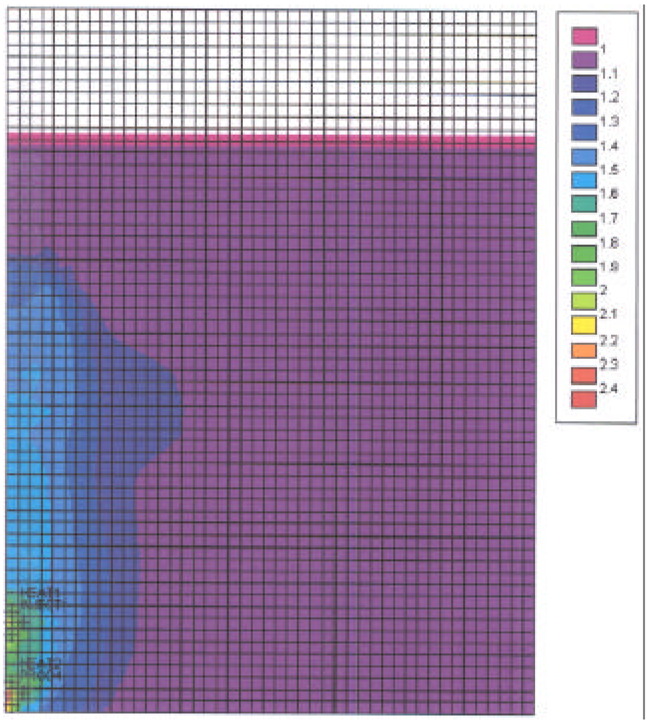


Figure 5. Permeability Multipliers after 6 months, Base Case

Other SAGD Geomechanics Studies

Geomechanical enhancement of the SAGD process has been reported by other authors. Ito and Suzuki (1996) [11] conducted a numerical simulation of the JACOS Hangingstone SAGD project in northern Alberta. They noted that if sufficient injection pressure is not utilized, economic performance might not be obtained. The authors explicitly cite the importance of geomechanical effects in SAGD process, and stated:

"A major difference in the operational setting is the steam injection pressure. A feasible oil production is obtained for the lower steam injection pressure when the geomechanical feature is not considered, while a higher pressure to have shear failure is required for good performance when the geomechanical module is used."

Similarly, Chalaturnyk and Li (2001)[12] simulated the effects of different operating pressures on the geomechanical behaviour of oil sands. The authors examined shallow, medium depth, and deep reservoirs (150m, 265m, 742m depths, respectively), which are comparable depths to those of the Devon UTF, Surmont, and Senlac projects. Three injection pressures and two horizontal stress states were examined.

They found that operating at the lowest injection pressures often did not result in failure. This is because the benefits of the higher pressure were offset by increases in thermal stresses, which were too localized at early times to allow for vertical stress relief, i.e., the stresses increased isotropically, which resulted in higher confining stresses and oil sands strengths. The beneficial effect of failure was most pronounced for the case with the most anisotropic stress state, as expected.

None of their examples examined the case of operating the steam chamber near overburden pressures. This would certainly result in shear failure and dilation of oil sands. For their deep reservoir, an injection pressure of 15,000 kPa increased the absolute permeability by 26%; while an operating pressure of 5,000 kPa had no appreciable beneficial effects. They stated:

"… any operator forced to operate at a low injection pressure for these conditions would not gain the advantage of shear induced volume changes and the increases in absolute permeability associated with these volume changes."

In both studies, the best increases in absolute permeability were achieved at the highest injection pressures.

Conclusions

A reservoir simulation model, which solves both geomechanical effects and thermal reservoir effects, has been successfully applied to SAGD.

Laboratory tests on specimens of undisturbed oil sands have conclusively proven that absolute permeability increases dramatically with dilation. Conventional core specimens are already disturbed, and therefore incorporate the effects of geomechanically-enhanced permeability. More high quality laboratory data, on physical responses of the oil sands and the magnitude of permeability increases, are required for different confining stresses and for a large range of samples.

Shear dilation of the oil sands was shown to enhance the permeability and the SAGD process. Dilation increases significantly at failure, therefore SAGD projects should induce oil sands failure for optimal geomechanical performance. The most effective means of ensuring this is to operate the steam chamber at or near the minimum total stress. Thus, the effective stress, and therefore the strength of the oil sands, will fall towards zero. Almost all reservoirs have anisotropic stress states before steam injection; therefore, the simple act of raising the pressure will ensure shear failure. Continued steaming will add thermal stresses.

In this simulation, below shear failure, dilation and permeability enhancement occurred principally near the horizontal wells.

The results presented in this paper cover a limited range of operating conditions and reservoir conditions. Significant work remains to be done to fully explore the implications of coupled modelling over a wider range of operating and reservoir conditions.

Conventional reservoir simulations do not account for geomechanical enhancement explicitly, but implicitly include the effects by using permeabilities from highly disturbed core. This presupposes that the oil sands will shear and dilate *in situ*, as has fortuitously happened in almost all high-pressure SAGD projects to date. This behaviour is only achieved by operating at the low confining stress only possible with high-pressure injection

Dilation and permeability enhancement are unlikely to occur in low pressure SAGD projects where the confining stress is not lowered sufficiently, by high-pressure injection, to induce shearing.

Acknowledgments

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Nomenclature

k_2	current absolute permeability
k_1	original absolute permeability
C_{nl}	proportionality constant
ε_v	volumetric strain
$\Delta\varepsilon_v{}^e$	elastic component of volume change
$\Delta\varepsilon_v{}^d$.	plastic component of volume change
$\Delta\varepsilon_v$	incremental volumetric strain
$\Delta\varepsilon_1$	incremental maximum principal strain
ϕ^*	ϕ_{cv} for loose sands
ϕ_{cv}	friction angle at constant volume
ϕ_μ	grain-to-grain friction angle for dense sands
σ_m'	mean effective stress
σ_1'	maximum principal effective stress
σ_3'	minimum principal effective stress

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