Caprock Integrity Analysis in Thermal Operations: An Integrated Geomechanics Approach

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Abstract

Caprock integrity is as critical as it is complex in thermal injection process such as steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). Continuous steam injection triggers complex coupled thermal and hydraulic processes, which can dramatically alter the in-situ stresses, reduce rock strength, induce new fractures or reactivate existing fractures posing continued risk of containment breach of caprock. Conventionally, fracture pressure typically measured from mini-frac test is considered as the upper limit of the net injection pressure. However, cases of compromising the integrity of caprock have been reported despite keeping the net injection pressure below the fracture pressure. Shear failure of rock was found to be one of the major causes for breaching the caprock in most of these cases.

In this paper, we present an integrated geomechanics approach to evaluate caprock integrity in thermal operations. The alteration of in-situ stresses caused by steam injection cannot be easily predicted by basic analytical methods, it requires sophisticated numerical modeling of the reservoir and the surrounding rock. Hence, as part of this integrated approach, we use coupled modeling between dynamic reservoir model and geomechanical model to quantity the effects of steam injection and changes in stresses on caprock integrity. To demonstrate the capability of this approach, we present a case study from Northern Alberta oil sands area in which caprock integrity was investigated for the proposed injection plan of 30 bar with injection rate of 200m3/day.

1. Introduction

Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) are the two most popular thermal oil recovery methods in heavy oil reservoirs where the oil in the form of bitumen is essentially immobile. In a typical SAGD operation, a horizontal well pair (two horizontal wells, injector and producer, parallel to each other and separated by a constant vertical distance, typically 5 m) is drilled at the bottom of a thick unconsolidated sandstone reservoir. As the steam is injected, a steam chamber is developed around these wells which grows upwards to the top of the reservoir and then begin to extend horizontally. The heat and the steam rise, whereas condensed water and mobilized oil flow downward through the porous unconsolidated sandstone reservoir. As the steam is injected, a steam chamber is developed around these wells which grows upwards to the top of the reservoir and then begin to extend horizontally. The heat and the steam rise, whereas condensed water and mobilized oil flow downward through the porous unconsolidated sandstone reservoir. As the steam is injected, a steam chamber is developed around these wells which grows upwards to the top of the reservoir and then begin to extend horizontally. The heat and the steam rise, whereas condensed water and mobilized oil flow downward through the porous unconsolidated sandstone reservoir.

In Cyclic Steam Stimulation (CSS), steam is injected into a well for a period of several days to several weeks and the heat is allowed to soak into the formation surrounding the well for an additional time (weeks). The oil is then produced until the rate drops below an economic limit. A steam flood may follow CSS by alternating between the well pairs to sweep oil between them. Steam is injected in one well and oil is produced in another well [Clark, 2007].

Continuous steam injection triggers complex thermal and hydraulic processes which can dramatically alter the formation pressure and temperature leading to various changes within the reservoir as well as in the surrounding rock. As steam is injected, the pressure and temperature in the reservoir rise. The increased temperature and pressure
cause changes in in-situ stresses, rock properties, porosity, permeability, etc. High temperature and injection pressures can reduce rock strength, induce new fractures and activate existing fractures. This poses a continued risk of breaching the containment of caprock and fault reactivation, which can provide pathways for bitumen and steam to flow to aquifers or to the surface causing significant risk to safety and the environment. Therefore, ensuring caprock integrity is critical in any subsurface injection process such as SAGD and CSS.

Conventionally, fracture pressure typically measured/interpreted from mini-fracturing (mini-frac) test is considered as the upper limit of the net injection pressure. However, some cases of compromising the integrity of caprock have been reported despite keeping the net injection pressure below the fracture pressure. These cases clearly indicate that designing the injection pressure scheme solely based on mini-frac test is not sufficient. Because, fracture pressure estimated from mini-frac test considers tensile failure only. Rock can fail in tension, shear or in combination of other complex modes. Consideration of other modes of failure in addition to tensile failure must be an essential part of caprock integrity analysis.

In the following sections, an integrated geomechanics approach to caprock integrity analysis in thermal operations is presented. This approach integrates data from logs, core analysis, field measurements with coupled reservoir-geomechanical numerical modeling which considers various failures modes.

### 2. Effect of Increased Pressure

In porous rocks, the normal stress (σ) at any point within the rock matrix is shared by the grains and the water held within the pores. The component of the normal stress acting on the grains, is called effective stress, and is generally denoted by σ'. Geomechanical calculations consider effective stresses in failure analysis which can be represented mathematically,

\[
\sigma' = \sigma - \alpha P_p
\]

where \(\sigma\) = total stress acting on the rock mass,
\(\sigma'\) = effective stress (net stress carried by the rock matrix),
\(P_p\) = pore pressure,
\(\alpha\) = Biot’s poroelastic coefficient (approaches unity in highly porous media).

Effective stresses depend on pore pressure, higher the pore pressure, lower the effective stresses. When steam is injected, temperature and pore pressure in the reservoir increase. This not only decreases effective stress but also has several other effects on the mechanical behavior of rock as described below.

- Injection pressure increases pore pressure which in turn decreases confining pressure. At low confining pressures, shear strength of rock reduces significantly [Handing and Hager, 1957], making rock susceptible to fail in shear easily.
- Increase in pore pressure can cause (i) dilation within steam chamber as well as in the adjacent layers, (ii) transient increase in overburden and horizontal stress within steam chamber, and (iii) deficiency in horizontal stresses at the boundary of steam chamber among many other effects. These effects can lead to micro shear fractures in the cap layer right above the reservoir.
- Increase in formation pressure decreases the effective stresses that can make the existing fractures or faults more susceptible to reactivation.
- If effective stresses decrease significantly, and go below the tensile cut-off, inadvertent hydraulic fracturing can occur at the reservoir boundaries, with the potential for such fractures to grow upwards into and through the caprock.

### 3. Effect of Increased Temperature

In SAGD operations, temperature can rise up to 250°C and in some cases, as high as 350°C, this can induce a significant amount of thermal stresses.

\[
\sigma_r = \frac{\alpha E \Delta T}{1 - \nu}
\]  

(2)

For example, assuming a thermal expansion coefficient (\(\alpha\)) of \(10^{-5}/\text{°C}\), a Young’s Modulus (E) of 2.0GPa, and Poisson’s Ratio (\(\nu\)) of 0.3, the increase in effective horizontal stress for a temperature rise (\(\Delta T\)) of 300°C, can be, \(\sigma_r = 8.6 \text{MPa}\), this is equivalent to minimum horizontal stress in a typical shallow heavy oil reservoir.

- Although there will be an instantaneous increase in overburden stress due to high injection rate and rise in temperature, this increment can subside partly in the form of surface heave as there is no constraint on the free ground surface. However, due to lateral constraint from adjacent rock, horizontal stresses experience large increase. This contrast creates shear fractures within the reservoir which is good for increasing reservoir permeability, but when these fractures extend to inter-bed boundaries, they can ultimately lead to generalized shear failure at caprock interface.
- Mechanical properties of rock are temperature dependent. Stiffness and strength decrease with increasing temperature [Horsud, 1998; Lempp and Welte, 1994]. Tensile strength as well as compressive strength can decrease remarkably in shales as temperature increases. In a study conducted by Closmanna and Bradley (1979), Young’s modulus showed a considerable decrease with temperature.
- When temperature difference rises greater than 80-100°C, yielding can be expected even in materials such as oil sands that are less stiff and unconsolidated than highly competent rock such as a carbonates. In softer rocks, stress changes are less than in stiff rocks, but the stresses needed for yield are far lower because soft rocks like unconsolidated sandstones are much weaker than stiff rocks [Dusseault, 2008].
4. Caprock Integrity Analysis

Rock can fail in tension, compression/shear or from a combination of these modes as shown in Figure 1. Increase in both the pressure and temperature act together in favor of rock failure by creating tensile as well as shear fractures within the reservoir. Shear dilation and fractures give rise to considerable amount of volumetric strain which increases permeability in the reservoir. Experimental studies performed by Touhidi-Baghini [1998] showed that increase in permeability is directly related to volumetric strain which is mainly caused by shear fractures. For core samples with an average porosity of 34%, the increase in permeability due to volumetric strain can be as high as 6.0 and 1.6 times the original permeability in vertical direction and horizontal direction, respectively. Shear failure due to high pressure steam injection within the reservoir is beneficial, which to a degree what is intended in SAGD operations. However, if these fractures grow and extend to the overlying shale layers (cap layers), then it can lead to shear failure at the shale interface compromising on its containment ability.

Traditionally, Mohr’s circle is used to visualize the normal and shear stresses and to determine graphically shear strength of the materials. Figure 2 illustrates the use of Mohr’s circle, in which horizontal and vertical axes represent effective normal stress ($\sigma'_n$) and shear stress ($\tau$), respectively. Green semi circle, called the Mohr’s circle, represents the virgin state of minimum ($\sigma'_3$) and maximum ($\sigma'_1$) in-situ effective stresses. Mohr’s circle represents the stress on any plane cut through the material. The blue line in Figure 2 represents linear form of shear failure envelope, typically determined from triaxial testing of core samples.

The shear strength of rock at failure ($\tau_f$) is given by the Coulomb failure criterion, expressed as,

$$\tau_f = c + \sigma'_n \tan \phi$$

where $\tau_f$ = shear stress at failure
$\sigma'_n$ = the normal effective stresses on the failure plane,
$c$ = the cohesion, and
$\phi$ = the friction angle.

These are called strength parameters of rock. The blue line (failure envelope) in Figure 2 is essentially, shear strength of the material.

The Coulomb failure criterion can be re-written in terms of the maximum ($\sigma'_1$) and minimum ($\sigma'_3$) effective stresses using Mohr’s circle as follows,

$$F = \sigma'_1 + \sigma'_3 + (\sigma'_1 - \sigma'_3) \sin \phi - 2c \cos \phi = 0$$

Equation 4 is referred to as the Mohr-Coulomb failure criterion. Although there are several advanced shear failure criteria used in rock mechanics, Mohr-Coulomb failure criterion is one of the most commonly used to assess shear failure. When Mohr’s circle touches the failure envelope, shear failure is considered to have occurred. Thus the maximum shear stress caused by a change in operating pressure and temperature can be evaluated using this criterion.

Figure 3 illustrates use of Mohr-Coulomb criterion to understand effects of increased pressure and temperature in SAGD operations.

The green semi circle, representing virgin state of in-situ stresses before injection is far from the failure envelope in Figure 3. When injection starts, several alterations takes place as described in previous section.
(i) Pore pressure increases, effective stresses decrease which causes Mohr’s circle to move to the left, closer to failure envelope, increasing the chances of shear failure (in this case size of the circle remains same as the green circle).

(ii) Increase in pore pressure causes increase in total stresses. In a normal reservoir setting, since the material is confined by adjacent material laterally, strain in lateral direction can give rise to increase in lateral stresses. Whereas strain in vertical direction can be compensated in the form of surface heave as there is no constrain in that direction due to free ground surface [Settari, et al. 1993]. These boundary conditions cause the total stress in the lateral direction to increase considerably, while the total vertical stress experiences only a little change as steam is injected. This causes the Mohr’s circle to become larger as it moves to the left to touch the shear failure envelope as shown in Figure 3, the brown semi circle.

(iii) As described in previous section, increase in temperature creates thermal stresses which change total stresses. This effect when combined with the stress changes due to increased pressure causes Mohr’s circle to become even larger as it moves to the left as shown in Figure 3 where \( \sigma^*_{1} \) and \( \sigma^*_{3} \) are altered maximum and minimum effective stresses due to steam injection.

(iv) As the steam chamber grows, first high temperature front moves upwards, when it hits the shale cap layer, dehydration (loss of water) occurs in shale [Dusseault, 2008]. This can create micro fractures in the cap layer, increase its permeability and deteriorate hydraulic integrity of the caprock. If steam reaches shale, enters these micro-fractures and increases the clay-bound water content in shale which drastically decreases cohesion as well as friction angle of shale. This phenomenon will reduce shear strength as shown in Figure 3. Brown line represents altered failure envelope or reduced shear strength.

\[
\tau^*_f = c^* + \sigma^*_n \tan \phi^* \tag{5}
\]

The strength parameters in Equation 5 with superscript * are altered parameters due to temperature.

To summarize, changes in pressure and temperature, (a) move the Mohr’s circle to the left, closer to the failure envelope; (b) make Mohr’s circle bigger in size, increasing chances of touching the failure envelope; (c) lower the failure envelope, increasing chances of touching Mohr’s circle; essentially, make the rock more susceptible to fail in shear.

When the steam front reaches the shale cap layer (after the dehydration process and micro-fractures are created), and reduces to a liquid state by condensation, it is absorbed by the shales. This can cause shale to swell and increase lateral stresses. Shale swelling also reduces its Young’s modulus and peak strength considerably [Bashbush et al., 2009]. In addition to various effects due to the increased pressure and temperature, shale swelling will only makes the situation worse by facilitating breakage of shale laminations.

Predicting tensile failure is relatively easy as it can be interpreted from fracture pressure estimated from a mini-frac test. However, prediction of shear failure or combination of other modes is a complex subject. It involves a number of parameters and requires sophisticated numerical modeling of the reservoir and the surrounding rock. Accurate estimation of dynamic changes in stresses and rock properties due to steam injection requires coupled numerical modeling between reservoir simulation (thermal fluid flow) and geomechanical modeling (changes in stress, strain and dilation).

5. Integrated Geomechanics Approach

An optimized operating pressure in SAGD operations should be safe from caprock integrity standpoint and economical from production point of view. Prediction of optimized safe operating pressure depends on several key factors which include rock mechanical properties, rock strength, in-situ stresses, and changes in rock’s reservoir properties like porosity, permeability, water saturation etc., and in-situ stresses due to steam injection. In order to estimate these parameters as accurately as possible, data from the following sources are essential:

- Sonic logs with anisotropic parameters and other petrophysical logs;
- Image Logs (fracture identification);
- Mini-Frac or Leak-off test (break down pressure and closure stress);
- Formation pressure measurement; and
- Core test (rock mechanical properties and rock strength, high temperature relative permeability besides the routine core tests) for reservoir rock as well as caprock. Shear strength of caprock is one of the key parameters required.

Data from these sources are integrated with coupled reservoir-geomechanics modeling to estimate induced stresses and changes in rock strength due to steam injection. These changes will be ultimately used to assess shear failure as well as tensile failure in the caprock. The complete workflow for integrating the data from various sources is illustrated in Figure 4 and briefly described below.

Step 1: After acquiring the relevant data, first step is to construct a One-Dimensional Mechanical Earth Model (1-D MEM) for a minimum of three offset wells and for the proposed well pairs. A 1-D MEM will provide essential rock mechanical properties, rock strength and stresses as a continuous profile along the well trajectories at log-scale resolution [Khan et al., 2010]. Image logs, mini-frac or LOT, formation pressure and core tests are critical in calibrating the 1-D MEM.
Step 2: Correlating data, especially rock mechanical properties from 1-D MEMs of offset wells and proposed well pairs, laterally as well as vertically. Seismic data is used to correlate properties between these wells.

Step 3: Once 1-D MEMs are correlated, rock properties are distributed in a geological model for the entire project area (using seismic velocity cube if available). This will include geological structural features, any existing fractures and faults in the area.

Step 4: A three-dimensional Mechanical Earth Model (3-D MEM) covering the entire project area is constructed using the property model developed in Step 3. This 3-D model consists of reservoir, overburden up to surface, under-burden and side-burden up to sufficient distance to eliminate any boundary effects that may have on the results. Initial stress analysis is performed to model the virgin state of in-situ stress (pre-injection and pre-production state). These modeled initial stresses are calibrated using the calibrated stress profile from 1-D MEMs along each offset well trajectory.

Step 5: Coupled reservoir-geomechanics modeling is conducted to quantify the changes in in-situ stresses caused due to steam injection. For each injection scenario, changes in temperature ($\Delta T$) and changes in pressure ($\Delta p$) are computed in the reservoir simulation software, ECLIPSE$^\text{TM}$. Corresponding changes in stresses ($\Delta \sigma$) and volumetric strains ($\Delta \varepsilon$), porosity ($\Delta \phi$), and permeability ($\Delta k$) are computed in VISAGE$^\text{TM}$ (a 3D finite element based geomechanics simulation software), iteratively. The values of $\Delta \phi$ and $\Delta k$ are fed back to ECLIPSE$^\text{TM}$ for computing new $\Delta p$ and $\Delta T$.

Step 6: Once the coupled reservoir-geomechanical modeling is conducted for the proposed injection plan, the new stress state is obtained and checked against the failure criteria for tensile, shear and other complex failure modes. The stress path and strains, calculated from the coupled simulations, are used to predict the possible occurrence and location of mechanical failures in the primary caprock. If any major faults are present in the area, then the possibility of fault reactivation is also assessed in this phase.

6. Case Study Example

Using the approach described above, mechanical integrity of the caprock of a SAGD pad in the Northern Alberta oil sands area has been investigated. Operator of this pad was planning to exploit the bitumen using SAGD. The main purpose of this
The study was to assess if that caprock integrity was maintained for the proposed injection plan. As part of this study, initial in-situ stresses as well as altered states of in-situ stresses due to steam injection was modeled using coupled reservoir-geomechanics modeling.

The main geological formations considered in the model were: Wabiskaw shale (primary caprock), McMurray sand (reservoir), and carbonate underburden layers. The average reservoir properties and geomechanical properties used in the model are listed in Table 1 and Table 2, respectively.

Table 1: Average reservoir properties.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Property</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Caprock permeability</td>
<td>$K_h = 0.002 \text{ mD,}$</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$K_v = 0.002 \text{ mD}$</td>
<td></td>
</tr>
<tr>
<td>McMurray sand permeability</td>
<td>$K_h = 6000-1500 \text{ mD,}$</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$K_v = 3000 - 200 \text{ mD}$</td>
<td></td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>2000 kPa</td>
<td></td>
</tr>
<tr>
<td>Initial reservoir temperature</td>
<td>12 °C</td>
<td></td>
</tr>
</tbody>
</table>

Table 2: Average geomechanical properties in the reservoir and over and underlying formations.

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Young's Modulus (MPa)</th>
<th>Poisson's Ratio</th>
<th>UCS (MPa)</th>
<th>Friction Angle (Degree)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wabiskaw Shale</td>
<td>1230</td>
<td>0.38</td>
<td>3.1</td>
<td>20</td>
</tr>
<tr>
<td>(caprock)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>McMurray Sand</td>
<td>2650</td>
<td>0.31</td>
<td>5.2</td>
<td>35</td>
</tr>
<tr>
<td>(reservoir)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Limestone</td>
<td>38,560</td>
<td>0.26</td>
<td>80</td>
<td>43</td>
</tr>
<tr>
<td>(underburden)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Mechanical Properties and Stresses:

1-D MEMs were constructed for three offset wells utilizing all the available data from logs to estimate the dynamic rock mechanical properties and rock strength. The dynamic properties were converted to the static using regional correlations. Publicly available lab data were used to calibrate static mechanical properties for the McMurray sand and the caprock (Wabiskaw) shale. The calibrated static properties are shown in Table 2.

Overburden stress was computed by integrating bulk density log:

$$\sigma_v = g \int_0^z \rho_b(z) dz$$

Where $\sigma_v$ is the overburden stress, $\rho_b$ is the bulk density, $g$ is the acceleration due to gravity, $z$ is the vertical depth. The gradient of $\sigma_v$ was found to be 20.8 kPa/m.

The minimum horizontal stress, $\sigma_h$, was estimated using the poroelastic equation:

$$\sigma_h = K_0 (\sigma_v - \alpha P_p) + \alpha P_p$$

In this equation, $\alpha = 1$ and $K_0 = \frac{\nu}{1 - \nu}$, where $\nu$ is Poisson’s ratio. The minimum horizontal stress, $\sigma_h$ profile computed from Equation 7 was calibrated using mini-frac data available in reservoir sand section as well as caprock shale section. The calibrated minimum horizontal stress gradient was found to be 16.58 kPa/m in the reservoir sand and 21.2 kPa/m in caprock shale. Overall, $\sigma_h$ gradient varied from 16.2 kPa/m to 21.5 kPa/m depending on stratigraphic sections. This is consistent with typical stress gradients observed in the area. Unconfined Compressive Strength (UCS) and shear strength parameters, cohesion (c) and friction angle ($\phi$) are critical input required for estimating safe SAGD operating pressure. Although UCS and $\phi$ can be estimated from sonic logs using strength and stiffness correlations, they need to be calibrated using core data. These strength parameters are typically obtained by conducting a triaxial test on a number of core samples. Subsequently, the failure envelope and strength parameters are estimated by plotting the results from the triaxial test on a Mohr-Coulomb diagram.

3-D Mechanical Earth Model:

Using the calibrated 1-D MEMs, a 3-D MEM was constructed covering the reservoir, overburden up to surface, under-burden (1000m below the base of the reservoir) and side-burden (about 500m each side). The original reservoir grid including two layers to account for over and underlying formation consists of 80x10x58 cells as shown in Figure 5. The reservoir grid was embedded with 28, 10 and 16 additional layers on each side of the reservoir model. The final geomechanical embedded grid used in the 3-D MEM was of size of 108x20x74 as shown in Figure 6. Mechanical properties and strength parameters were estimated in the 1-D MEMs and populated in the 3-D MEM using Krigging interpolation technique honoring the built in geological structural features in PETREL.
As a first step in geomechanical numeral modeling, initial stress analysis was conducted (using VISAGE™) to estimate the virgin state of in-situ stress (pre-injection and pre-production state). The in-situ stresses estimated from 3-D MEM were compared with the ones computed in 1-D MEM along the well profiles, which were in good agreement. Once the initial stress state (VISAGE™), temperature and pressure (ECLIPSE™) were established, next step was to conduct the coupled reservoir-geomechanics modeling.

![Geomechanical Model - Embedded Grid](image)

Figure 6: Embedded geomechanical grid for 3-D MEM.

**Coupled Reservoir-Geomechanics Modeling:**

In order to gain confidence in results of coupled modeling, few initial steps of coupled simulation were run to verify the reservoir behavior, and to ensure realistic rise in pressure, temperature and steam chamber growth. Later, actual coupled simulations were run to investigate caprock integrity for the proposed steam injection pressure of 30bar with an injection rate of 200m³/day. Results from the coupled simulation for the proposed injection plan indicated no failure in the caprock. In order to predict the worst case scenario and to estimate the factor of safety available for the proposed injection plan, additional simulations were run for a 60 bar steam injection pressure.

Figures 7 to 9 show changes in temperature, volumetric strain and permeability enhancement due to the steam injection after a period of 8 months, 3 years, 5 years and 8 years of injection. Figure 7 illustrates how the steam chamber grew and temperature front moved upwards first and then laterally. Maximum of 12% volumetric strain was observed in the first three years which helped the steam chamber to grow fast as shown in Figure 8. In subsequent steps, volumetric strain remained same in the middle of the chamber but increased at the shoulders of the chamber, which indicated expansion of the steam chamber further away from the injector.

Increase in the permeability mainly due to volumetric strain is shown in Figure 9. Maximum horizontal permeability enhancement was about 3000mD with an average enhancement of about 1800 mD throughout the steam chamber.

The subsequent changes in horizontal and vertical stresses after three years of steam injection are shown in Figure 10 and Figure 11. Clearly, there is a significant amount of change in both horizontal and vertical stresses. In these figures, blue color indicates decrease and red color indicates increase in the stresses. There is a substantial increase in the horizontal stresses within the reservoir and slight decrease on top of the steam chamber (one layer below the base of caprock) as shown in Figure 10.

![Change in temperature after 8 months, 3, 5 and 8 years of injection (clockwise from left top corner).](image)

Figure 7: Change in temperature after 8 months, 3, 5 and 8 years of injection (clockwise from left top corner).

![Volumetric strain after 8 months, 3, 5 and 8 years of injection (clockwise from left top corner).](image)

Figure 8: Volumetric strain after 8 months, 3, 5 and 8 years of injection (clockwise from left top corner).
Maximum increase in the minimum horizontal stress within the reservoir after three years of injection was 1376 kPa (about 20% increase compared to initial/pre-injection stress). Whereas the maximum decrease at the base of caprock in the minimum horizontal stress is about 740 kPa (about 7% decrease compared to initial stress in the caprock).

There is a slight increase in the vertical stress at the boundaries of steam chamber, and decrease in sections adjacent to the steam chamber as shown in Figure 11. Overall, only a slight change was observed in the vertical stress. The amount of decrease is higher than the amount of increase in the vertical stress. This variation creates a stress contrast at the boundaries which can induce shearing stresses.

Although there were considerable amount of changes in stresses due to proposed injection plan of 30bar steam injection pressure, these changes did not cause mechanical failure in the primary caprock layers.

In order to determine the maximum safe operating pressure, injection pressure was ramped up to double (60bar, i.e. 6000kPa) the proposed initial injection pressure but still below the fracture pressure (7350 kPa was the closure stress estimated from mini-frac test interpretation). After three years of continuous steam injection at 60bar injection pressure, the changes in stresses and failure scenarios results are shown in Figure 12 and Figure 13. Although, the effective stress in the primary cap layer decreases significantly it did not cause tensile failure. Figure 12 shows the effective minimum stress where the blue color indicates the higher effective stress and red as the lower effective stress. When the effective stress becomes zero or negative, tensile fractures would be created. In Figure 12, the base of the caprock has yellowish red color but not red, indicating absence of any tensile failure or fracturing.

At the same time step (three years of injection period), base of the caprock seems to be at the verge of shear failure as shown in Figure 13. In this figure, when the displayed shear failure index becomes zero or positive, shear or combination of other failure modes would occur. The failure index indicates susceptibility to shear failure, and can be visualized as the distance between the failure envelope and Mohr’s circle in a Mohr-Coulomb shear failure diagram. If the Mohr’s circle intersects the failure envelope, then the index would be positive; if it touches the failure envelope then the index would be zero, and if it is under the failure envelope, then the index would be negative. The higher the index value in negative more stable would be the rock from shear failure.
Furthermore, this index also gives a rough idea of how much shear stress would be required to cause failure. For example, an index of -100 means failure can occur if the existing shear stress exceeds by another 100 kPa. In this case study, the failure index for base of the caprock is -20, meaning the base of the caprock is about to fail if the steam injection pressure of 60 bar (6000 kPa) were used. It further proves and should be noted that even though the steam injection pressure of 6000 kPa is less than the fracture pressure of 7350 kPa, estimated from mini-frac test, it causes other modes of failure in the caprock. Therefore, keeping the injection pressure below the fracture pressure without consideration for the other modes of failure is not necessarily safe for SAGD operations. The actual limit of net injection pressure from this analysis was found to be 6000 kPa which gives an approximate factor of safety of 2.0 for the proposed injection plan of 3000 kPa.

7. Conclusions

- An integrated geomechanical approach for caprock integrity in thermal operations is developed and successfully applied for a field study.
- The example considered in this clearly demonstrates that keeping the injection pressure lower than the fracture pressure (determined from mini-frac tests) does not necessarily guarantee caprock integrity.
- Not only the tensile failure but other failure modes must also be incorporated to understand the possible effects of thermal processes on reservoir containment.
- To predict shear or other complex failure modes, coupled reservoir-geomechanical modeling is required.
- Integrating all the available data with geomechanical modeling and simulation can allow for proactive planning and direct preventative measures to avoid catastrophic events.

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References


