Overburden characterization with formation pore pressure and anisotropic stress field estimation in the Athabasca Basin, Canada

Carmen C. Dumitrescu¹ and Draga A. Talinga¹

Abstract

One of the challenges encountered during the life cycle of an oil-sand thermal-production reservoir is the prediction of the formation pore pressure and in situ stress regime during the assessment phase of the reservoir development and, more importantly, during the development phase. We have investigated the state of formation pore pressure and stress in the overburden — represented by the Clearwater Formation, Grand Rapids Formation, and Colorado Group — of a preproduction oil-sands reservoir situated in the Athabasca Basin of Alberta, Canada. Our methodology integrates pressure data from piezometers, stress data from mini-frac (MF), dipole sonic logs, and elastic properties obtained from multicomponent 3D seismic inversion data. It combines the Terzaghi effective stresses with the Schoenberg and Sayers elastic stiffness matrix for horizontal transversely isotropic fractured materials. The total principal stresses (vertical, minimum, and maximum horizontal stresses) are expressed as functions of the normal fracture weakness (anisotropic correction factor), formation pore pressure, seismic data (Lamé constants), and the Biot-Willis coefficient. The effective principal stresses are estimated from the equivalent total principal stresses and the formation pore pressure multiplied by the Biot-Willis coefficient. On all three overburden intervals analysed, the relations between principal stresses indicate a normal stress regime. The estimated total minimum horizontal stress matches the MF values within 10%. The formation pore pressure, along with the 3D seismically derived estimates of the total and effective principal stresses, allows for better assessment of the caprock integrity and for operational savings based on a reduced number of MF tests. It can also be used for stress estimation within the formations hosting aquifers, which is so important for thermal production. Understanding the subsurface on the reservoir area is important for efficient production, but knowing the subsurface of the overburden is equally important for reducing potential issues due to production.

Introduction

Understanding the magnitudes and orientations of the in situ principal stresses is important to characterize a basin in terms of its overall geomechanics and to establish anomalous stress trajectories in a particular area (Bell, 1996; Zoback, 2007). The in situ stresses are assumed to be oriented in three mutually orthogonal directions: vertical (σv), maximum horizontal (σh1), and minimum horizontal (σh2). The vertical stress is usually inferred from the mass of the material overlying the measured point, and because the rock density is variable, the overburden stress is obtained by integrating the density with respect to volume from the surface to the depth of interest. The horizontal stresses also vary with depth due to the difference in the mechanical properties of the rock; i.e., a brittle material experiences more horizontal stress than a ductile unit (Bell, 1996). In the context of their geologic setting, comprehensive mapping of horizontal stress magnitudes is very important because the information can be used for designing the well casing, evaluation of wellbore stability, planning deviated or horizontal wells to produce a reservoir, predicting the fracture gradient, or for planning hydraulic fracturing (Zhang and Zhang, 2017). The horizontal stresses could be estimated from well tests such as mini-frac (MF), leak-off pressure, or step rate tests. In the MF case, a fracture is initiated by injecting a fluid at high pressure and in a short pulse within the formation, through perforations in a cemented casing. The fracture continues to propagate until the pumping stops. The pressure at which the fracture closes is considered to be equivalent to the total minimum principal stress acting on it. The fracture develops perpendicular to the direction of the minimum principal stress. The test is repeated by reopening the induced fracture to check the repeatability and consistency of the fracture closure pressure estimation (MF/diagnostic fracture injection test analysis report, Big Guns Energy Services, 2016). A caveat to this measurement is that the pressure and stress measurements are obtained only at a specific

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depth and represent the local conditions, which can vary laterally away from the test location. Our goal is to obtain continuous 3D estimates of the in situ principal stresses in the area covered by seismic data.

The in situ stress field can be reconstructed from the stress-induced anisotropy of rocks using the relationship between the elastic properties, confining stresses, and formation pore pressure (Talinga and Dumitrescu, 2019). As a consequence of Terzaghi’s effective stress law (Terzaghi, 1943), the accuracy of stress estimation depends on the ability to evaluate the formation pore pressure, the pressure acting on fluids in the pore space of the formation. Within sedimentary rocks, current practices for determining the formation pore pressure include the routine monitoring of pore water pressure using borehole-installed piezometers.

In this paper, the formation pore pressure and in situ principal stresses are evaluated within the overburden with special care taken for caprock characterization. The overburden is defined as the geologic column above the producing McMurray Formation. In this case, the overburden consists of the glacial Quaternary and the sands and shales of the Colorado and Mannville Groups (Figure 1).

Formation pore pressure and stress magnitudes are very closely connected (Zoback, 2007). In some of the petroleum basins, formation pressure is at overpressure levels and can even reach 95% of the overburden stress causing problems with wellbore stability and sometimes drilling incidents. In the Athabasca Basin, the formation pore pressure is abnormal, below hydrostatic pressure (Conly et al., 2002). In this area, knowing the formation pore pressure is important for the estimation of stresses because the presence of water in the pore space implies that the total stress at any point within the rock mass is shared by the solid grains (effective stress) and the water within the pores (formation pore pressure).

**Geologic settings**

The Athabasca Basin, one of the three oil-sand basins in northeastern Alberta, contains large deposits of bitumen held primarily in the Lower Cretaceous McMurray Formation, which directly overlies the sub-Cretaceous unconformity. The dominant stratigraphic model for the McMurray Formation is fluvoestuarine (Hubbard et al., 2011). As presented in Figure 1, the reservoir is overlain by the overburden: the Clearwater and the Grand Rapids Formations of the Mannville Group overlain by the Colorado Group (Barson et al., 2001; Hubbard et al., 2011; Haug et al., 2014) represented by the Viking and Joli Fou Formations. The Clearwater Formation is a regionally continuous layer composed predominantly of shales with interbedded mudstones. Shales are clastic rocks with fine grains (less than 2 μm). These are rocks of highly variable composition and structure. The major components of shales are clay minerals (montmorillonite, illite, smectite, and kaolinite), muscovite, Quartz, feldspar, and calcite. The term shale designates rocks whose clay mineral content (clay volume divided by total volume) is greater than 35% (Vernik et al., 1993). The presence of the anisotropic clay minerals causes elastic anisotropy of shales (Sayers and den Boer, 2018). The shales form the reservoir caprock and have the role of blocking the vertical migration of the steam by confining the stresses and the deformations induced during the thermal oil recovery process.

From a hydrostratigraphic point of view, the Cretaceous interval (the Mannville and Colorado Groups) consists of sandy aquifers and shaly aquitards that play an important role in the thermal production. These are, in ascending order (Figure 1), the McMurray-Wabiskaw aquifer/aquitard system, the Clearwater aquitard, the Grand Rapids aquifer, the Joli Fou aquitard, and the Viking aquifer (Bachu and Underschultz, 1993). Within the aquifers, measured formation pore pressure varies between 1000 and 2000 kPa, depending on location. These lower pressures suggest that the Cretaceous section is below the normal hydrostatic conditions. All Mannville aquifers within our study area are underpressure, topography-driven flow systems, with ground water flowing from higher elevation recharge areas to adjacent lower elevation discharge areas, represented by local river valleys along the formations outcrop (Barson et al., 2001).

Within the sedimentary rocks of the Athabasca Basin, stress measurements...
indicate anisotropic stress conditions (Bell et al., 1994); therefore, the Cretaceous successions are expected to exhibit a stress-induced anisotropy even in the absence of natural fractures.

Formation pore pressure

Formation pore pressure, the pressure acting on fluids in the pore space of the formation, is important for the prediction of stress dynamics and geomechanical effects during the production of oil sand reservoirs because any injection of fluids is accompanied by stress changes within the reservoir and the caprock (Lavrov, 2016). For this study, the piezometers were placed in sands and shales of the Colorado Group and only in sands of the lower Grand Rapids and Clearwater Formations. For all these of three intervals, the measured formation pore pressure values \( P_p \) are below the normal hydrostatic pressure \( P_{\text{hydro}} \) indicating an abnormal regime. Hence, all well-log-based methods — velocity ratio method, density ratio method, and velocity method (as in Eaton, 1975) — cannot be used to predict the formation pore pressure.

Initially, the formation pore pressure within the Clearwater Formation was modeled based on hydrostatic pressure using equation 1, where \( k \) is a correction factor determined from averaging measured formation pressures and equal to 2300 kPa in the study area (Talinga and Dumitrescu, 2019):

\[
P_p = P_{\text{hydro}} - k.
\] (1)

The hydrostatic pressure \( P_{\text{hydro}} \) is calculated at depth \( z \) from the ground surface using equation 2, for a fluid with average density \( \rho_{\text{fluid}} \) of 1.01 kg/m\(^3\) and a typical value of 9.81 m/s\(^2\) for the vertical component of gravitational acceleration \( g \):

\[
P_{\text{hydro}} = \rho_{\text{fluid}} g z = 9.9 z.
\] (2)

In this paper, we used 48 formation pore pressure measurements taken from 26 wells to derive linear depth-trend relations. The depth-trend relations presented in Table 1 and Figure 2 are based on 8 measurements for the Colorado Group, 23 measurements for the Grand Rapids Formation, and 17 measurements for the Clearwater Formation. Based on the available data, the formation pore pressure gradients have values between 0.25 and 2.14 kPa/m, much lower than the hydrostatic pressure gradient of 9.9 kPa/m (depending on salinity). There are differences between gradients within each of the three intervals, possibly due to differences in consolidation and diagenesis effects. These differences were taken into account in the presented formation pore pressure model. For the Colorado Group, the formation pore pressure measurements were acquired in sand and also in shale, which is remarkable because, in general, shales are impermeable and direct measurements are very difficult (Zoback, 2007). As a result, two relations are presented. Formation pore pressure in the overburden ranges from the low side of hydrostatic in the Colorado Group, to severely underpressure (approximately 50% of the hydrostatic pressure) in the Grand Rapids Formation and Clearwater Formation (Figure 2). The values measured in shale are higher than the ones measured in sand.

| Table 1. Linear depth-trend relations used to estimate formation pore pressure within each of the three depth intervals of the overburden based on local piezometer data. Separate relations are derived for measurements in sands and measurements in shales of the Colorado Group. |
| Colorado Group | \( P_p = 0.27z + 1259 \) (5 measurements in sand) |
| Colorado Group | \( P_p = 2.14z + 1119 \) (3 measurements in shale) |
| Grand Rapids Formation | \( P_p = 1.04z + 1032.3 \) (23 measurements in sand) |
| Clearwater Formation | \( P_p = 0.25z + 1400 \) (17 measurements in sand) |

Figure 2. Hydrostatic pressure (in blue) along with formation pore pressure depth trends for the Colorado Group (shale in gray, sand in orange), Grand Rapids Formation (in red), and Clearwater Formation (in dark blue). Pressure values are in kPa. The dots represent the measured points, and the lines represent the best extrapolation. For all three depth intervals, the data points are below hydrostatic pressure.
As part of our study, we wanted to investigate what the relation is between the estimated formation pore pressure, porosity, and vertical effective stress. In Figure 3, we present shale and sand porosity depth trends for five depth intervals of the overburden: Colorado, combined upper and middle units A and B of the Grand Rapids Formation (GRPD AB), the lower unit C of the Grand Rapids Formation (GRPD C), the combined upper and middle units A and B of the Clearwater Formation (CLRW AB), and the lower unit C of the Clearwater Formation (CLRW C). These trends are derived from more than 200 wells within the study area, and they are situated at very shallow depth (between 150 and 550 m). Based on the statistics detailed in Table 2, sand porosity (0.25–0.44) is higher than shale porosity (0.22–0.35) with very small gradients for all depth intervals. This is the opposite of the normal compaction trend. We assume that this is because of the shallow depth of the unconsolidated overburden and of the underpressure regime.

As presented in Table 2 and Figure 3, porosity increases at a very small rate when compared with the formation pore pressure and effective vertical stress gradients. It is important to note that in a normal pressure regime, the porosity of shale is expected to decrease as the vertical effective stress increases (Zoback, 2007).

### Total and effective anisotropic stress field

The in situ stress state can be completely characterized by the magnitude and orientation of the principal stresses: the vertical stress $\sigma_v$, the minimum horizontal stress $\sigma_h$, and the maximum horizontal stress $\sigma_H$. According to Anderson’s faulting theory (Anderson, 1951), the three major classes of faults — normal, reverse, and strike-slip — are the results of the three principal stress regimes: the normal stress regime, in which the vertical stress is the greatest principal stress, the reverse stress regime, in which the vertical stress is the least principal stress, and the strike-slip stress regime, in which the vertical stress is the intermediate principal stress.

Understanding the deformation and failure of a rock mass is highly dependent on how appropriately the effective stress models are developed and applied (Zoback, 2007; Gray, 2017). Previously, Talinga and Dumitrescu (2019) propose a method for the description of the anisotropic stress field, based on the assumption that the unequal stresses

### Table 2. Shale and sand porosity along with formation pore pressure, and vertical effective stress variation for five depth intervals of the overburden: Colorado, combined upper and middle units A and B of the Grand Rapids Formation (GRPD AB), the lower unit C of the Grand Rapids Formation (GRPD C), combined upper and middle units A and B of the Clearwater Formation (CLRW AB), and the lower unit C of the Clearwater Formation (CLRW C).

<table>
<thead>
<tr>
<th>Shale porosity</th>
<th>Sand porosity</th>
<th>Formation pore pressure (kPa)</th>
<th>Effective vertical stress (kPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Colorado</td>
<td>0.25–0.31</td>
<td>(43,671 points)</td>
<td>0.06–0.36 (464 points)</td>
</tr>
<tr>
<td>GRPD AB</td>
<td>0.22–0.32</td>
<td>(38,911 points)</td>
<td>0.26–0.36 (21,083 points)</td>
</tr>
<tr>
<td>GRPD C</td>
<td>0.25–0.34</td>
<td>(22,776 points)</td>
<td>0.31–0.39 (35,864 points)</td>
</tr>
<tr>
<td>CLRW AB</td>
<td>0.25–0.35</td>
<td>(32,457 points)</td>
<td>0.29–0.38 (48,370 points)</td>
</tr>
<tr>
<td>CLRW C</td>
<td>0.24–0.32</td>
<td>(17,139 points)</td>
<td>0.25–0.44 (1733 points)</td>
</tr>
</tbody>
</table>

Note: Points refer to the number of samples from all wells.
imposed on a porous rock may result in a stress-induced anisotropy of the medium. The material's properties can be expressed using the Schoenberg and Sayers (1995) stiffness matrix for fractured media with horizontal transversely isotropic (HTI) symmetry, in which the symmetry axis is oriented horizontally perpendicular to the fracture planes (Bakulin et al., 2000). The method considers the decomposition of internal stresses into effective stress, the effective component causing the deformation of the solid skeleton, and formation pore pressure, a component that is transmitted to the fluid that occupies the porous space. The horizontal stresses formulations were derived using Sayers (2010) matrix form of stress-strain relations expressed in terms of effective stresses:

$$\sigma_{ij}^{\text{effective}} = \sigma_{ij}^{\text{total}} - \alpha P_p \delta_{ij},$$  

(3)

where $\sigma_{ij}$ effective is the effective stress tensor, $\sigma_{ij}^{\text{total}}$ is the total stress tensor, $P_p$ is the formation pore pressure, $\alpha$ is the Biot-Willis coefficient, and $\delta_{ij}$ is the tensorial form of the Kronecker delta, which equals one if $i = j$ and zero if $i \neq j$. The Schoenberg and Sayers (1995) HTI stiffness matrix, given in equation 4, was substituted in the stress-strain constitutive relation, known as Hooke’s law (Hooke, 1678):

$$\begin{pmatrix}
\lambda_b (1-\delta_N) & \lambda_b (1-\delta_N) & \lambda_b (1-\delta_N) & 0 & 0 & 0 \\
\lambda_b (1-\delta_N) & \lambda_b (1-\delta_N) & \lambda_b (1-\delta_N) & 0 & 0 & 0 \\
\lambda_b (1-\delta_N) & \lambda_b (1-\delta_N) & \lambda_b (1-\delta_N) & 0 & 0 & 0 \\
0 & 0 & 0 & \mu_b & 0 & 0 \\
0 & 0 & 0 & 0 & \mu_b (1-\delta_N) & 0 \\
0 & 0 & 0 & 0 & 0 & \mu_b (1-\delta_N)
\end{pmatrix}.$$

(4)

Through the stiffness matrix, the properties of the material under unequal stresses were characterized in terms of the Lamé constants of the unfractured background rock (incompressibility, $\lambda_b$ and rigidity, $\mu_b$) and the normal fracture weakness $\delta_N$ describing the rock’s behavior under stress. The material was assumed laterally confined and therefore undergoing only uniaxial deformations. The formation pore pressure was considered to be an independent variable.

The expressions for the total horizontal stresses as derived by Talinga and Dumitrescu (2019) are functions of total vertical stress $\sigma_{v}^{\text{total}}$, formation pore pressure $P_p$, the Biot-Willis coefficient $\alpha$, and coefficients $m$ and $n$, and can be written as

$$\sigma_h^{\text{total}} = m \sigma_v^{\text{total}} + \alpha P_p (1 - m),$$  

(5)

and

$$\sigma_H^{\text{total}} = n \sigma_v^{\text{total}} + \alpha P_p (1 - n).$$  

(6)

Coefficients $m$ and $n$ are the functions of the Lamé constants of the unfractured background ($\lambda_b$ and $\mu_b$) and the normal fracture weakness $\delta_N$, which corrects for anisotropy as shown in equations 7 and 8:

$$m = \frac{\lambda_b (1 - \delta_N)}{(\lambda_b + 2 \mu_b) (1 - \frac{\lambda_b^2 \delta_N}{(\lambda_b + 2 \mu_b)^2})},$$  

(7)

and

$$n = \frac{\lambda_b (1 - \lambda_b \delta_N / (\lambda_b + 2 \mu_b))}{(\lambda_b + 2 \mu_b) (1 - \frac{\lambda_b^2 \delta_N}{(\lambda_b + 2 \mu_b)^2})}.$$

(8)

The total vertical (overburden) stress $\sigma_v^{\text{total}}$ is produced by the weight of the overlying formations, and it can be obtained by integration of rock densities from surface to the depth of interest, $z$:

$$\sigma_v^{\text{total}} = \int_0^z \rho(h) dh,$$

(9)

where $g$ is the gravitational acceleration and $\rho(h)$ is the density as a function of depth.

The maximum and minimum horizontal stresses (presented in equations 5–8) are functions of the Lamé constants of the background rock ($\lambda_b$ and $\mu_b$), normal fracture weakness, vertical stress, formation pore pressure, and the Biot-Willis coefficient. The workflow proposed by Talinga and Dumitrescu (2019) is presented in Figure 4. We will briefly introduce and discuss the contribution of each of these elements to the estimated stresses in the study area situated in the Athabasca oil sands.

Lamé elastic coefficients, incompressibility $\lambda$ and rigidity $\mu$ were estimated through joint prestack PP-PS inversion analysis of the seismic volumes. As input for the joint prestack PP-PS inversion we used PP angle gathers, with incidence angles up to 50°, and PS angle gathers converted to PP time, with incidence angles up to 65°. The frequency content of the PP seismic data ranges between 8 and 160 Hz, and the frequency content of the PS seismic data ranges between 12 and 60 Hz. A group of angle-dependent wavelets extracted from these two sets of angle gathers was used for the inversion, along with a low-frequency model based on several dipole wells within the survey.

The elastic parameters, P-wave impedance, S-wave impedance, and density estimated using the joint prestack PP-PS inversion (Hampton and Russell, 2013) were further improved using multivariate and probabilistic neural network analysis (Russell et al., 1997; Hammon and Russell, 2001). This workflow was used and presented in more detail in previous Athabasca oil sands case studies (Dumitrescu et al., 2014; Mayer et al., 2015). The low-resolution PS seismic data have a great contribution for the estimation of the elastic parameters from joint prestack PP-PS inversion in oil-sands reservoirs (Dumitrescu et al., 2014), mainly because of the bitumen viscoelasticity at temperature of 15°C–20°C. Probabilistic neural network analysis (PNN) was applied in an effort to account for nonlinear relationships between logs and seismic data (Dumitrescu et al., 2009).
In all multiattribute and PNN analysis, the most significant seismic attributes include PP and PS information (Dumitrescu et al., 2015).

The elastic parameters, P-wave impedance \(I_p\), S-wave impedance \(I_s\), and density \(\rho\) were used to estimate Lamé elastic coefficients, incompressibility \(\lambda\) and rigidity \(\mu\) (Goodway et al., 1997), and they are written as

\[
\lambda = (I_p^2 - 2I_s^2)/\rho \quad (10)
\]

and

\[
\mu = I_s^2/\rho. \quad (11)
\]

Normal fracture weakness parameter is used as an anisotropy correction parameter for stress. The normal and tangential fracture weakness parameters (\(\delta_N\) and \(\delta_T\), respectively) characterize anisotropy and relate the normal and shear excess compliances due to fractures, to the total compliance of the fractured material. They are used to model not necessarily fractures but the rock behavior under stress. Following Talinga and Dumitrescu (2019), the fracture weaknesses are modeled using the elastic stiffness of the equivalent HTI anisotropic medium formulated by Schoenberg and Sayers (1995) based on the linear slip theory of Schoenberg (1983). The stiffness matrix contains components of the isotropic background medium (Lamé constants \(\lambda_b\) and \(\mu_b\)) and fractures contributions \(\delta_N\) and \(\delta_T\), which are generally stress dependent (equation 4). The effective fracture model is obtained by Backus averaging (Backus, 1962) the density, P-wave velocity, and the fast and slow S-wave velocities recorded from well logs. Even though the components of the stiffness matrix cannot be exactly recovered due to the limited number of measurements, we proposed an approximation of the normal fracture weakness based on the constraints on the compressional velocity of the intact rock. The tangential fracture weakness is estimated from the velocities of the fast \(V_{S0\text{fast}}\) and slow \(V_{S0\text{slow}}\) S-waves propagating vertically and polarized parallel and perpendicular to fractures.

Analysis of dipole sonic logs indicates that S-wave splitting occurs within the Clearwater and the Grand Rapids Formations suggesting that the medium is azimuthally anisotropic. For the Colorado Group, there was less available well information, but the analysis indicates a medium with low azimuthal anisotropy.

The fracture weakness \(\delta_N\) was estimated based on incompressibility \(\lambda_b\) and rigidity \(\mu_b\) Lamé constants of the background rock, as presented in our previous paper (Talinga and Dumitrescu, 2019)

\[
\delta_N = (\lambda_b + 2\mu_b - C_{33}) \frac{\lambda_b + 2\mu_b}{\lambda_b^2}, \quad (12)
\]

where \(C_{33}\) is determined from the vertical P-wave velocity \(V_{P0}\) and density as in equation

\[
C_{33} = \rho V_{P0}^2. \quad (13)
\]

The tangential fracture weakness \(\delta_T\) was determined from the elastic stiffness coefficients \(C_{44}\) and \(C_{55}\) (Talinga and Dumitrescu, 2019)

\[
\delta_T = \frac{C_{44} - C_{55}}{C_{44}}, \quad (14)
\]

where

\[
C_{44} = \rho V_{S0\text{fast}}^2 \quad (15)
\]

and

\[
C_{55} = \rho V_{S0\text{slow}}^2. \quad (16)
\]

This implementation was applied in three depth intervals of the study area. A summary of the normal and tangential anisotropy correction factors for these intervals is presented in Table 3.

The low values of the anisotropy correction factors for the Colorado Group are consistent with the polygonal cracking patterns observed within the Viking Formation of the Colorado Group. These polygonal cracking patterns are attributed to the water loss and differential compaction of the sediments (R. Damer, personal communication, 2017). Because the fractures have inconsistent orientations, the anisotropy is weak.

Figure 4. General workflow for seismic reconstruction of the in situ anisotropic stress field (Talinga and Dumitrescu, 2019).
The Biot-Willis coefficient, also called the effective stress coefficient, is the coefficient that multiplies the formation pore pressure in equation 3. It was initially defined as coefficient \( \alpha \) by Biot (1941) and revisited by Biot and Willis (1957) and Biot (1962) as

\[
\alpha = 1 - \frac{K_{\text{dry}}}{K_m}, \tag{17}
\]

where \( K_{\text{dry}} \) is the dry bulk modulus and \( K_m \) is the mineral bulk modulus. After approximating

\[
K_{\text{dry}} \cong K_m \left(1 - \frac{\phi}{\phi_c}\right), \tag{18}
\]

where \( \phi \) is the porosity and \( \phi_c \) is the critical porosity (porosity above which grain-to-grain contact is lost and hence shear strength vanishes), the Biot-Willis coefficient can be written as

\[
\alpha \cong \frac{\phi}{\phi_c}. \tag{19}
\]

In this paper, initially we estimated the Biot-Willis coefficient based on a rock-physics model for each interval and the porosity values from logs. However, because log porosity and critical porosity are very similar for the above-mentioned intervals, a value of 0.8 was used for the Biot-Willis coefficient in all intervals.

The sands and shales of the overburden are highly variable in composition and structure. For example, percentages of quartz range between 28% and 73%, smectite (water sensitive) clay ranges between 28% and 43%, and kaolinite and illite range between 23% and 46% within the intervals.

From a conventional point of view, the Biot-Willis coefficient is a poroelastic parameter, characterizing the deformation of a material when the formation pore pressure changes (Biot and Willis, 1957). It depends on the state of confinement, increasing with reducing stress. Even though most laboratory measurements of the Biot-Willis coefficient indicate a single value, usually high for porous reservoir rocks, especially in anisotropic rocks, the coefficient is directionally dependent and can be mathematically described as a tensor (Gray, 2017).

**Results and discussions**

The formation pore pressure relations for sands, presented in Table 1, were used to estimate the 3D formation pore pressure within the Colorado Group, Grand Rapids, and Clearwater Formations. Two buried Quaternary bedrock channels (Rayner and Rosenthal, 2008) are present in the study area and are marked with A and B in Figure 5, where the top boundary is bedrock. An arbitrary surface mimicking the regional Viking outside the channels but drawn flat within the channels was used to model the formation pore pressure based on the relationship for the Colorado Group. The composite formation pore pressure volume characterizes the entire overburden sedimentary section, from the top of the Colorado Group (Viking Formation) to the base of the Clearwater

<table>
<thead>
<tr>
<th>δN</th>
<th>δT</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.04</td>
<td>0.01</td>
</tr>
<tr>
<td>0.12</td>
<td>0.03</td>
</tr>
<tr>
<td>0.19</td>
<td>0.03</td>
</tr>
</tbody>
</table>

Table 3. Normal and tangential anisotropy correction factors for three depth intervals of the overburden.

![Figure 5. Composite west–east vertical depth section of the formation pore pressure, with values inferred from linear relations for the Colorado Group, Grand Rapids, and Clearwater Formations, presented in Table 2. High values (1575 kPa) are in warm colors, and low values (1250 kPa) are in cold colors. Valid results for the interval Viking-Wabiskaw, and inside bedrock channels.](image)

![Figure 6. Composite west–east vertical depth section of the seismically derived total vertical stress. High values (8300 kPa) are in warm colors, and low values (2050 kPa) are in cold colors.](image)
Formation (top of the Wabiskaw Member). An example of a composite vertical depth section is displayed in Figure 5, with the formation pore pressure values correlating well with the piezometer measurements.

The vertical stress was estimated by multiplying the gravitational acceleration \( g \) with the integrated density over increasing depth. A composite west–east vertical depth section of the seismically derived total vertical stress is shown in Figure 6. For all three overburden intervals, the largest magnitudes are for the vertical stress followed by the maximum horizontal and minimum horizontal stress (\( \sigma_V > \sigma_H > \sigma_h \)), which characterizes a normal stress regime.

Total minimum stress solutions obtained from seismic estimation are within 10% the MF measurements. Figure 7 shows a comparison between the MF measurements and the seismic estimations for all three overburden intervals.

Of interest for production monitoring is the lowest caprock interval — the basal shale unit C of the Clearwater Formation. Figure 8 displays as horizon slices the lateral variation of the total vertical stress (values between 4200 and 9000 kPa), maximum horizontal stress (values between 4200 and 6200 kPa), and minimum horizontal stress (values between 4200 and 6200 kPa) within this depth interval. MF test wells are indicated by the circles, and stress values from seismic and MF at the well locations are presented for comparison. The values of the minimum horizontal stress are within 10% of the calculated values from the MF test.

The basal shale unit C of the Clearwater Formation is in a normal stress regime because the vertical stress is the highest principal stress. Throughout the survey area, the minimum horizontal stress values within the lowest caprock interval exceed the SAGD operating injection pressures of the producing McMurray Formation. The maximum operating injection pressure, as mandated by the provincial regulatory authority, is well below the stress values calculated in the C unit of the Clearwater Formation.

The difference between the maximum horizontal and the minimum horizontal stress is the horizontal stress anisotropy. Figure 9 displays a composite west–east vertical depth section of the horizontal stress anisotropy, along with a horizon slice of the lateral variation of horizontal stress anisotropy within the basal shale unit C of the Clearwater Formation. The composite seismically derived horizontal stress anisotropy shows increasing values with depth: an average of 10 kPa for the Colorado Group, approximately
150 kPa for the Grand Rapids Formation, and approximately 300 kPa for the Clearwater Formation. Within our study area, the Colorado Group is almost isotropic, and there is a strong lateral variation of the stress anisotropy within the Grand Rapids and Clearwater Formations.

Conclusion

A detailed seismic reconstruction of the in situ anisotropic stress field has been carried out in an oil-sands project, using the method proposed by Talinga and Dumitrescu (2019). The method assumes that unequal horizontal stresses are responsible for the observed azimuthal anisotropy, if the anisotropy is weak. This suggests that knowledge of the stress-induced anisotropy can be used to find expressions for the principal horizontal stresses, through an anisotropy correction factor, represented by the normal fracture weakness parameter. The method also shows that the anisotropy correction factor can be estimated based on relationships between the normal and tangential fracture weaknesses, determined from density and P-wave and slow and fast S-wave velocities measured at wells. The method also addresses the complexity of the solid-fluid system by introducing the formation pore pressure as an independent variable. The total and effective principal horizontal stresses are estimated using anisotropy information obtained from dipole sonic logs, formation pore pressure modeled from piezometers data, and elastic properties obtained from joint PP-PS prestack seismic data inversion.

The formation pore pressure field was modeled using linear relationships between formation pore pressure local measurements and depth for the Colorado Group, the Grand Rapids Formation, and the Clearwater Formation depth intervals. Because the measured formation pore pressures are below the hydrostatic pressure, the entire sequence analyzed is in an underpressure regime.

Modeling results of the fracture weaknesses at wells suggest a clear anisotropy differentiation between the formations, with increasing values of the normal component with depth, from 0.04 for the Colorado Group, to 0.12 for the Grand Rapids, to 0.19 for the Clearwater.
Consequently, the smallest difference in horizontal stresses is observed within the formations of the Colorado Group, which appear to be almost isotropic.

Total and effective estimated magnitudes of the vertical, maximum horizontal, and minimum horizontal stresses allow for better understanding and imaging of the stress regime in the oil-sands project covered by the seismic survey. Direct measurements obtained with MF tests allow only for the total minimum horizontal stress values. The predicted magnitudes of the minimum total horizontal stress are within 10% of MF tests performed at several depth intervals within the Viking, Joli Fou, Grand Rapids, and Clearwater Formations. The relative magnitude of the estimated principal stresses indicates a normal stress regime within the 180–400 m depth interval, also well-supported by the vertical orientation of the pressure-induced fractures, controlled by the stress condition in formation.

The general agreement between results from application of this method and results from MF tests, suggest that the stress formulations, along with an accurate estimate of the anisotropy correction factor and the formation pore pressure field, can provide a robust solution for the 3D characterization of the in situ anisotropic stress state in a large portion of the overburden.

Even though challenges still exist in theoretical and practical estimation of the stress field, the information obtained has direct application to hydrocarbon production and potentially in monitoring stress changes within the reservoir and caprock during production.

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Data and materials availability

Data associated with this research are confidential and cannot be released.

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