NUMERICAL INVESTIGATION OF POLYMER INJECTION EFFECTS
ON GEOMECHANICAL RESERVOIR PROPERTIES
DURING ENHANCED OIL RECOVERY

by

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ABSTRACT

Polymer injection is an enhanced oil recovery method based on the viscosity increase of the injected aqueous phase to control its mobility. The changes in mobility could affect the pore pressure distribution within the reservoir. The objective of this research work is investigating the effects of polymer injection on the geomechanical stress distribution within a reservoir. Specific objectives include sensitivity analysis of the polymer rheology to determine changes in reservoir stress magnitudes.

A coupled fluid flow-geomechanics numerical reservoir simulator is used to investigate the effect of polymer rheology on the stress distribution and magnitude within a reservoir. A hypothetical reservoir model is developed considering a heterogeneous rock properties distribution. A combination of water injection and polymer injection treatments is modeled at different injection rates. For the sensitivity analysis, the effective mean stress changes are compared at different times during the process. Maximum and minimum stresses are used to determine the rock failure criteria at different polymer viscosities and injection rates. We determine the rock failure criteria using the Mohr-Coulomb failure envelope.

Water injection efficiency, in terms of oil recovery, increased after the first polymer injection treatment. During polymer injection, effective mean stress increased with time. Compared to the effective mean stress during water injection, polymer injection mean effective stress showed higher values in most cases. At depths where there was high water saturation, the pore pressure was higher causing the decrease of effective mean stress at that time. At a higher polymer injection rate, on average, the effective means stress increases fifty percent at the less water saturated zones. At the high pore pressure zone, the increase in effective mean stress was
not as high with the second polymer injection compared with the first one. The maximum stress values decreased with time. Stress magnitudes were affected by both water injection and polymer injection. Their behavior has similar tendencies when compared to reservoir depths. Changes in the stress magnitudes will cause rock failure at different viscosities.

Results from this study provide insight on the changes of stress magnitudes of the rock expected during polymer injection. The results and observations presented in this work could lead to feasibility assessment, development and design of monitoring technologies for estimation of polymer slug location, and provide means for estimating of the EOR treatments efficiency.
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<tr>
<td>EMS</td>
<td>Effective Mean Stress</td>
</tr>
<tr>
<td>Sl</td>
<td>Liquid saturation</td>
</tr>
<tr>
<td>M</td>
<td>Mobility ratio</td>
</tr>
<tr>
<td>ko</td>
<td>Oil permeability</td>
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<tr>
<td>Sv</td>
<td>Overburden stress</td>
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<tr>
<td>k</td>
<td>Permeability</td>
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<tr>
<td>Pp</td>
<td>Pore pressure</td>
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<tr>
<td>Pv</td>
<td>Pore volume</td>
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<tr>
<td>krg</td>
<td>Relative permeability</td>
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<tr>
<td>kro</td>
<td>Relative permeability oil</td>
</tr>
<tr>
<td>krw</td>
<td>Relative permeability water</td>
</tr>
<tr>
<td>S</td>
<td>Stress tensor</td>
</tr>
<tr>
<td>Co</td>
<td>Uniaxial compressive strength</td>
</tr>
<tr>
<td>v</td>
<td>Velocity</td>
</tr>
<tr>
<td>kw</td>
<td>Water permeability</td>
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<tr>
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<td>Water saturation</td>
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<tr>
<td>E</td>
<td>Young’s Modulus</td>
</tr>
<tr>
<td>a</td>
<td>Biot’s coefficient</td>
</tr>
<tr>
<td>µi</td>
<td>Coefficient of internal friction</td>
</tr>
<tr>
<td>ρ</td>
<td>Density</td>
</tr>
<tr>
<td>λo</td>
<td>Displaced oil</td>
</tr>
<tr>
<td>λw</td>
<td>Displacing water</td>
</tr>
<tr>
<td>Symbol</td>
<td>Description</td>
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<tr>
<td>--------</td>
<td>--------------------------------------</td>
</tr>
<tr>
<td>$\dot{\gamma}_{eff}$</td>
<td>Effective shear rate</td>
</tr>
<tr>
<td>$\sigma_{eff}$</td>
<td>Effective stress</td>
</tr>
<tr>
<td>$\sigma_1$</td>
<td>Maximum horizontal stress</td>
</tr>
<tr>
<td>$\sigma_3$</td>
<td>Minimum horizontal stress</td>
</tr>
<tr>
<td>$\mu_o$</td>
<td>Oil viscosity</td>
</tr>
<tr>
<td>$\nu$</td>
<td>Poisson’s ratio</td>
</tr>
<tr>
<td>$\phi$</td>
<td>Porosity</td>
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This research is dedicated to my father Jose Alberto Ramirez Vivas. Thank you for teaching me the necessary values to find success in life.
Primary recovery methods leave a large amount of hydrocarbons unrecovered. Secondary recovery methods are used to recover an additional percentage of hydrocarbons from the reservoir. Common secondary recovery methods such as water flooding or immiscible gas injection have been implemented on different reservoirs around the world for further oil recovery after primary production. After varied production time, enhanced oil recovery (EOR) methods are necessary to increase and maximize the recovery from an oil reservoir.

Polymer injection is a chemical injection method that has been implemented for several years. Polymer flooding is used to increase the water viscosity (i.e., decreases the injected phase mobility) and improve the oil sweep efficiency within the reservoir rock. A successful polymer flooding was done in the Daqing oil field located in northeast China. It was the world’s largest polymer flood. It began in 1995; it was done successfully for 12 years (Wang et al. 2008). Polymer flooding projects in heavy oil reservoirs such as Pelican Lake field and East Bodo field in Canada started in July 1997 and May 2006 respectively (Sheng et al. 2015).

Figure 1.1 shows a polymer injection process as an example, with one injector well and one producer well, indicating the typical injection phases of this EOR process. First, pre-flush a low salinity brine. Second, injection of a slug of polymer solution. Finally, conventional water injection.
Previous studies have been done on some of the effects of polymer injection on the geomechanics of the reservoir, such as Khodaverdian (2009) provide a geomechanical perspective on the generally complex problem of polymer flooding in unconsolidated formations containing viscous oil, and Li (2015) studies the effect of fracturing during polymer flooding. Undesirable rock shear failure or fracture propagation during polymer flooding could happen due to impurity and solids present in the injection fluid that plug the sand face over time, along with high in-situ oil viscosity and low polymer mobility (Teklu et al. 2012).

The main objective of this study is to understand the effects of polymer injection on the geomechanical properties of the reservoir. Results from this study provide insight on the changes of stress magnitudes of the rock expected during polymer injection. These results could be extended for the development of techniques to estimate the location of the polymer slug based on the magnitude of the changes in stress distribution. Knowing the location of the polymer slug would be useful to evaluate the efficiency of the chemical injection treatment.

Figure 1.1 Polymer injection process; adapted from (Donaldson et al. 1992).
1.1 Objectives

1.1.1 Research goal

- Understanding the effects of polymer injection in the geomechanical properties of the reservoir using a simulation model to predict changes on the stress magnitudes of the reservoir rock.

1.1.2 Specific Objectives

- Build a reservoir simulation model with the rock properties, fluid properties and geomechanical properties.
- Perform sensitivity analysis of the polymer rheology and viscosity to determine effect on the geomechanical stress distribution.
- Calculate changes of effective stress magnitudes during the polymer slug injection process.
- Assess if polymer injection could trigger rock failure using the Mohr-Coulomb failure envelope.
CHAPTER 2
LITERATURE REVIEW

2.1 Polymer Injection

The main purpose of polymer injection is to increase sweep efficiency by reducing the injected water mobility, which prevents viscous fingering and improves the water injection profile by preventing crossflow between vertical and heterogeneous layers. Because effective water permeability remains reduced after polymer flooding, subsequent waterflooding becomes more effective. The polymer molecules adsorb to the rock surface, reducing the relative permeability of water ($k_{rw}$) more than the relative permeability of oil ($k_{ro}$) through disproportionate permeability reduction (Sheng et al. 2015). There are a few parameters that affect the polymer injection process: reservoir temperature, clay content, formation water salinity, oil viscosity, formation permeability and divalent ions content. According to Wang et al. (2008), when designing a polymer injection process, many reservoir considerations have to be made: reservoir lithology, stratigraphy and reservoir heterogeneity, distribution of the remaining oil, well pattern and well distances.

Polymer injection limitations are low injection rates due to polymer high viscosity; polymer degradation due to high temperature; small tolerance to high salinity; and deterioration from shear stress while being pumped. Figure 2.1 shows a simple polymer injection workflow that illustrates how the process is done.
The most common type of polymer according to Zerkalov (2014) are: Polyacrylamide (PAM), Partially hydrolyzed polyacrylamide (HPAM) and Xanthan gum. The following are some of the most important characteristics of these types of polymer:

- **PAM (Polyacrylamide)**
  
  - Stable up to 194 °F
  
  - Not resistant to high salinity.
  
  - Molecular weight > $1.0 \times 10^6$ g/mol

- **HPAM (Partially hydrolyzed polyacrylamide)**
  
  - Stable up to 210 °F
  
  - High resistivity to mechanical forces present during flooding.
  
  - High sensitivity to salinity.

- **Xanthan gum**
  
  - Stable from 158 to 194 °F
• No sensitivity to high salinity and hardness.

• Molecular weight 2-50 x 10^6 g/mol

2.2 Mobility Ratio

The mobility ratio is the ratio between displacing fluid (water) and displaced fluid (oil). Equation 2.1 shows the ratio between water mobility to the oil mobility. Mobility ratio greater than one is not favorable to the displacement process. The result of low water viscosity and high oil viscosity is greater than one mobility ratio. In order to increase the viscosity of the water, it has to be mixed with a high molecular weight viscosifying agent (i.e., polymer). Polymer will increase the water viscosity and the mobility ratio will decrease towards favorable values (ideally less than one). Oil displacement process will improve generating a higher production rate. Polymer injection sweep efficiency increases with the reduction of the mobility ratio (Morelato et al. 2011)

\[
M = \frac{\lambda_{water}}{\lambda_{oil}} = \frac{k_{water}}{k_{oil}} \frac{\mu_{water}}{\mu_{oil}}
\] (2.1)

Viscous fingering effect is caused by a large difference between water viscosity (low) and oil viscosity (high). Fingering effect is undesirable; it increases with time and causes an important reduction on the production as soon as it reaches the production well (Zerkalov 2015).
2.3 Shear Thinning

Shear thinning can be described as the behavior of non-Newtonian fluids when under shear stress its viscosity is reduced allowing it to flow better. Non-Newtonian fluid’s viscosity changes when under shear stress.

The effective shear rate within the porous media is calculated with the following equation:

\[
\dot{\gamma} = \frac{\alpha v}{\sqrt{k \phi}}
\]  

(2.2)

Where \( \dot{\gamma} \) is the effective shear rate (sec\(^{-1}\)), \( \alpha \) is the shape factor (Sorbie et al. 2007), which is a dimensionless number and is a function of grain shapes and distribution, pore space connectivity and tortuosity. \( \alpha \) is in the range of 1 and 14. The local flow velocity is \( v \) (cm/sec) and \( k \) and \( \phi \) are the porosity and permeability of the formation.

\[
\mu_p = \mu_{p max} - \left( \frac{\dot{\gamma}}{\dot{\gamma}_{max}} \right) (\mu_{p max} - \mu_w)
\]  

(2.3)

Equation 3 shows the relationship between the viscosity of the viscous material and effective shear rate. As seen in this equation it decreases linearly with the effective shear rate. When \( \dot{\gamma} > \dot{\gamma}_{max} \), \( \mu_p = \mu_w \), in consequence, when the flow velocity is above zero, shear thinning is applied. This model assumes that during simulation only shear thinning is present.
2.4 Relative Permeability and Heterogeneity

The ratio of the phase effective permeability to the absolute reservoir permeability is the relative permeability. Equations 2.4, 2.5 and 2.6 show the relative permeability for oil, water and gas respectively. The relative permeability is dimensionless.

\[ k_{ro} = \frac{k_o}{k} \quad (2.4) \]

\[ k_{rw} = \frac{k_w}{k} \quad (2.5) \]

\[ k_{rg} = \frac{k_g}{k} \quad (2.6) \]

The sum of the relative permeability is always less than one and the sum of the phase permeability is not equal to the total permeability due to capillary forces that reduce the flow rate as Towler (2002) stated. According to Li (2015) polymer retention in the rock causes permeability reduction. The adsorption of polymer causes the effective pore size to decrease. Also, polymer molecules can be trapped in small pore throats, causing the plugging of flow path in the porous rock, known as the inaccessible pore volume.

Reservoir heterogeneity is a term used to describe the geological complexity of the reservoir, and also the relationship between that complexity with the flow of fluids through the reservoir. According to Slatt et al. (1993), it is composed by three scale heterogeneities:
• Wellbore scale heterogeneities
  o Pore network (pore throats and pores)
  o Grain composition and size
  o Grain packing
  o Lamination and bedding
  o Sedimentary structures

• Interwell scale heterogeneities
  o Lateral bedding geometries and continuity
  o Symmetrical lateral and vertical patterns
  o Variations of reservoir quality

• Fieldwide scale heterogeneities
  o Reservoir thickness
  o Facies geometries and continuity
  o Bulk reservoir properties

Wellbore data can be obtained from rock samples or well logs. Core samples often provide important data such as porosity, permeability, lithofacies, fluid saturation and stratification sequences. Interwell spacing is not easy to describe because lithofacies may not be continuous. Reservoirs are complex depositional systems. They need to be described at a small scale because they tend to compartmentalized. These compartments might not communicate.
2.5 Reservoir Geomechanics

2.5.1 Stress

Stress is defined as a force acting on a defined area. According to Zoback (2010) stress magnitudes depend on pore pressure, depth and active geologic processes with different spatial and temporal scales. In rock mechanics, the compressive stresses are positive. Equation 2.7 defines the nine components of the stress tensor acting on a homogenous, isotropic body at certain depth.

\[ S = \begin{bmatrix}
S_{11} & S_{12} & S_{13} \\
S_{21} & S_{22} & S_{23} \\
S_{31} & S_{32} & S_{33}
\end{bmatrix} \quad (2.7) \]

The stresses acting on the body will have one normal component and two shear components generating a total of three normal stresses and six shear stresses as shown in Equation 2.8,

\[ S = \begin{bmatrix}
\sigma_{xx} & \tau_{xy} & \tau_{xz} \\
\tau_{yx} & \sigma_{yy} & \tau_{yz} \\
\tau_{zx} & \tau_{zy} & \sigma_{zz}
\end{bmatrix} \quad (2.8) \]

The first subscripts in \( \sigma \) and \( \tau \) refers to the axis normal to the surface and the second subscript refers to the direction of the force. Figure 2.2 shows the stress tensor. The state of stress can be described at depth in terms of the principal stresses by using tensor transformation. The principal stress values are defined in Equation 2.9. Diagonalization of the stress tensor will make
the principal stresses match the eigenvalues of the stress tensor and the direction corresponds to the stress tensor’s eigenvectors.

\[
\begin{bmatrix}
\sigma_{xx} & 0 & 0 \\
0 & \sigma_{yy} & 0 \\
0 & 0 & \sigma_{zz}
\end{bmatrix}
\]  \hspace{1cm} (2.9)

Figure 2.2 Stress tensor showing three normal stresses and six shear stresses (Tutuncu 2015).
According to Zoback (2010) the earth’s surface is in contact with a fluid that cannot support shear tractions; it is a principal stress plane. One principal stress is acting normal to the surface plane and two principal stresses are acting in the horizontal plane. As shown in Figure 2.3, the three principal stress magnitudes are defined as the vertical stress from the overburden $S_v$, the maximum principal horizontal stress, $S_{H\text{max}}$ and the minimum principal horizontal stress $S_{h\text{min}}$. The normal faulting regime considers the maximum principal stress $\sigma_1$ as $S_v$, the intermediate principal stress $\sigma_2$ as $S_{H\text{max}}$ and the minimum principal stress $\sigma_3$ as $S_{h\text{min}}$.

![Figure 2.3 In situ stress state shows the overburden stress, horizontal maximum and minimum stress (Tutuncu 2015).](image)
Figure 2.4 In situ stress state for normal faulting; overburden stress is greater than horizontal maximum and minimum stress (Tutuncu 2015).

2.5.2 Pore pressure and effective stress

Pore pressure is considered of great importance in reservoir geomechanics. It is defined as the pressure of fluids inside the pores of the reservoir. The reduction of the pore pressure with depletion caused by production of hydrocarbon could cause deformation, compaction and permeability loss. Overburden stress is the vertical stress caused by the weight of the overlaying rock on the formation. Equation 2.10 shows the magnitude of $S_v$ as a function of density and depth.

\[
S_v = \int_0^z \rho(z) g \, dz \approx \bar{\rho} g z \tag{2.10}
\]

The difference between externally applied stresses and internal pore pressure is the effective stress law. Equation 2.11 shows the effective stress law, which defines the applied load
carried by the rock matrix. Equation 2.11 will be critical to study the effects of polymer injection in the geomechanical properties of the reservoir. For sandstone rock, the permeability is more sensitive to pore pressure than confining pressure (Zoback 2010).

\[
\sigma_{eff} = \sigma_v - \alpha P_p
\]  

(2.11)

2.5.3 Stress Effects on Porosity and Permeability

During depletion of the reservoir porosity changes with stress and pore pressure. Porosity reduction as result of depletion is typically small. Also, porosity change is heterogeneous because of rock heterogeneity and localized deformation. Reservoir rock permeability controls the rate of production during depletion. Permeability may change over the reservoir volume. These changes may cause barriers that will control how fluid flow during enhanced recovery operations. The preferred horizontal flow direction is parallel to the maximum in situ horizontal stress. Identification of the principal in situ stress directions is important for the reservoir drainage strategy (Fjaer et al. 2008).

2.5.4 Mohr Coulomb Failure Criterion and Subsidence

Linearized Mohr-Coulomb failure criterion is a common rock strength criterion that represents the linear envelope obtained from plotting shear strength of the material versus normal stress. It assumes that intermediate principal stress has no influence on failure. It only describes
shear failure and not tensile failure. Equation 2.12 shows the relationship between minimum and maximum stress with the uniaxial compressive strength,

\[ \sigma_1 = C_o + q \sigma_3 \]  

(2.12)

Where \( q \) depends on the coefficient of internal friction as shown in the following equation.

\[ q = \left[ \left( \mu_i^2 + 1 \right)^{\frac{1}{2}} + \mu_i \right]^2 \]  

(2.13)

As shown in Figure 2.5, shear failure starts when the difference between \( \sigma_1 \) and \( \sigma_3 \) exceeds a critical value, represented by the failure line, which changes with the type of formation that is being studied.

Figure 2.5 Mohr-Coulomb failure criteria showing the safe zone and the zone where there is shear failure (Tutuncu 2015).
Subsidence is the effect caused by reservoir compaction when the pore pressure is reduced, and the effective stress increases as shown in Figure 2.6. This causes the rock to shrink and the reservoir will compact.

Figure 2.6 Example of compaction and subsidence on a reservoir with one producing well (Craig 2014).

According to Fjaer (2008), one or many of the following conditions must be present to see a considerable degree of subsidence.

- Significant pressure drop. Water flooding to maintain pressure would counteract compaction.
- Highly compressible reservoir rock.
• Considerable reservoir thickness. An aquifer will contribute to compaction. Also part of the overburden if drained to the reservoir.
• Significant reservoir compaction as well as not shielded by reservoir rock.

Severe consequences can be generated by reservoir subsidence. Prediction on a timely manner will prevent this issue. Subsidence and compaction have to be predicted in order to properly design casing and platforms. Figures 2.6 shows compaction and subsidence affecting a reservoir.

2.6 Software Description

2.6.1 Stars™

Stars™ (Computer Modelling Group, 2015) is a three-phase multi-component thermal and steam additive simulator. The grid system may be Cartesian, cylindrical, or variable depth/thickness. Two types of configurations are possible. Two dimensional and three-dimensional configurations with any of the grid system described before. The concept of disperse components (stabilized dispersions on one phase to another) provides a unifying point of view in the modeling of polymer, gels, fines, emulsions and foam. Also, it handles fully implicit wells in a very robust fashion. The bottomhole pressure and the block variables for the blocks where the well is completed are solved fully implicitly. An extensive list of constrains such as minimum bottomhole pressure, wellhead pressure, GOR and others can be entered. Aquifers are modeled by either adding boundary cells that contain only water or by the use of a semi-analytical aquifer model.

According to Stars™ user guide (Computer Modelling Group, 2015), it provides an efficient and consistent method for handling these questions by discretizing wellbore flow and
solving the resulting coupled wellbore/reservoir flow problem simultaneously. Appropriate multiphase flow correlations are used to adjust wellbore flow patterns in an explicit fashion at the end of each time step. A geomechanical model consisting of three submodules is available for treating aspects of the above problems. The coupling between the geomechanical model and the simulator is done in a modular and explicit fashion. This increases the flexibility and portability of the model, and decreases computational costs.
This chapter discusses the variables and methods used to model the reservoir behavior during different recovery strategies. The recovery strategies done were water injection and two types of polymer injection treatments. Initial reservoir properties, grid modeling, sector selection, well pattern, aquifer, thermal rock types, component properties (water, polymer, dead oil, solution gas, gas liquid, equilibrium correlations (k-values), reference pressure and reference temperature), rock fluids, initial conditions and geomechanics.

3.1 Initial Properties of the Reservoir, Grid Modeling, Sector Selection, Well Pattern

CMG Builder and Stars reservoir simulation tools were used in this study. A reservoir model was developed using data from a conventional sandstone reservoir located in South America. Reservoir rock properties such as average porosity, average permeability, initial reservoir pressure, bubble point pressure, solution gas oil ratio, depth, area, original oil in place are shown in Table 3.1

The reservoir grid was built using 150 blocks in the $x$ direction, 150 blocks in the $y$ direction and 20 blocks for $z$. The grid blocks horizontal dimensions, $dx$ and $dy$, were set equal to 27 ft. The vertical dimension ($dz$) was divided in 20 layers as shown in Figure 3.1. Table 3.2 shows the thickness of the vertical layers from 1 to 20.
Table 3.1 Reservoir characteristics used to develop the simulation model

<table>
<thead>
<tr>
<th>Reservoir Characteristics</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (ft)</td>
<td>1400.00</td>
</tr>
<tr>
<td>Reservoir temperature (°F)</td>
<td>150.00</td>
</tr>
<tr>
<td>Initial pressure (psi)</td>
<td>1290.00</td>
</tr>
<tr>
<td>Bubble point pressure (psi)</td>
<td>1800.00</td>
</tr>
<tr>
<td>Solution GOR (scf/bbl)</td>
<td>600.00</td>
</tr>
<tr>
<td>Horizontal permeability (md)</td>
<td>50.00</td>
</tr>
<tr>
<td>Vertical permeability (md)</td>
<td>0.10</td>
</tr>
<tr>
<td>Net pay thickness (ft)</td>
<td>500.00</td>
</tr>
<tr>
<td>Areas (acres)</td>
<td>724.00</td>
</tr>
<tr>
<td>Porosity (fraction)</td>
<td>0.17</td>
</tr>
<tr>
<td>Connate water saturation (fraction)</td>
<td>0.35</td>
</tr>
<tr>
<td>Current oil saturation (fraction)</td>
<td>0.32</td>
</tr>
<tr>
<td>Initial oil saturation (fraction)</td>
<td>0.55</td>
</tr>
<tr>
<td>Residual oil saturation (fraction)</td>
<td>0.20</td>
</tr>
<tr>
<td>Oil formation volume factor (rb/stb)</td>
<td>1.10</td>
</tr>
<tr>
<td>OOIP (MMbbl)</td>
<td>225.00</td>
</tr>
<tr>
<td>Reservoir salinity (ppm)</td>
<td>3030.00</td>
</tr>
<tr>
<td>Net to gross ratio (%)</td>
<td>40.00</td>
</tr>
</tbody>
</table>

The depth to the top of the first layer is 1,150 ft. The pore volume multiplier of 1.5 was used for the whole grid. This is required to maintain the reservoir pressure at the level that sustains production. Table 3.3 shows the PVT Black Oil data inputs into the model.
Table 3.2 Vertical dimension (dz) used in the modeled reservoir

<table>
<thead>
<tr>
<th>Layer</th>
<th>Grid Thickness (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>25</td>
</tr>
<tr>
<td>2</td>
<td>28</td>
</tr>
<tr>
<td>3</td>
<td>32</td>
</tr>
<tr>
<td>4</td>
<td>34</td>
</tr>
<tr>
<td>5</td>
<td>34</td>
</tr>
<tr>
<td>6</td>
<td>34</td>
</tr>
<tr>
<td>7</td>
<td>34</td>
</tr>
<tr>
<td>8</td>
<td>34</td>
</tr>
<tr>
<td>9</td>
<td>35</td>
</tr>
<tr>
<td>10</td>
<td>35</td>
</tr>
<tr>
<td>11</td>
<td>35</td>
</tr>
<tr>
<td>12</td>
<td>36</td>
</tr>
<tr>
<td>13</td>
<td>35</td>
</tr>
<tr>
<td>14</td>
<td>36</td>
</tr>
<tr>
<td>15</td>
<td>33</td>
</tr>
<tr>
<td>16</td>
<td>100</td>
</tr>
<tr>
<td>17</td>
<td>125</td>
</tr>
<tr>
<td>18</td>
<td>125</td>
</tr>
<tr>
<td>19</td>
<td>125</td>
</tr>
<tr>
<td>20</td>
<td>125</td>
</tr>
</tbody>
</table>

Table 3.3 Reservoir hydrocarbon properties, black oil data for PVT file

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Gas Oil Ratio, GOR (scf/stb)</td>
<td>80.00</td>
</tr>
<tr>
<td>Oil gravity, API</td>
<td>20.00</td>
</tr>
<tr>
<td>Gas specific gravity (fraction)</td>
<td>0.70</td>
</tr>
<tr>
<td>Water specific gravity (unitless)</td>
<td>1.00</td>
</tr>
</tbody>
</table>
Figure 3.1 Reservoir model. Last five layers show the aquifer in place.

For the simulation, a reservoir sector was defined. It has 19 blocks in the $x$ direction, seven blocks in the $y$ direction, the same 20 blocks in the $z$ direction, and the same cell dimensions as in the original reservoir. Figure 3.2 shows sector one. The sector area is 96,957 ft$^2$. The pore volume for the selected sector is equal to 7,696,810 ft$^3$.

Figure 3.2 shows the selected configuration—inside the selected sector, an inverted nine spot well pattern with 18 production wells and three injection wells. The distance between production wells was assumed 81 ft in the horizontal and vertical axis. An injection rate of 502 bbl/day of polymer per injection well was used. The injection period was determined using the
pore volume previously discussed. The injection time was 1095 days. This time would be the equivalent to the injection of one pore volume of the sector at an injection rate of 502 bbl/day per injector well. A minimum bottomhole pressure constraint of 300 psi was entered.

Figure 3.2 The sector from the reservoir used for the simulations. Inverted nine spot patterns.

The reservoir was considered heterogeneous. Dykstra-Parsons coefficients higher than 0.7 (Castro et al. 2013) were found in a similar reservoir. For the reservoir sector of interest, the average porosity is 0.16 (unitless) and its average permeability in the $x$ and $y$ direction is 68.6
md, on the $z$ direction is 0.10 md as shown in Figures 3.3 and 3.4 respectively. Each well (injection and production) had 15 open perforations. Results for the 15 layers will be studied for some cases in this research.

Figure 3.3 Average porosity value for the fifteen producing layers of the sector of the reservoir.
Figure 3.4 Average permeability values for the fifteen producing layers of the sector of the reservoir.
3.2 Aquifer, Thermal Rock Types, Component Properties

An aquifer was created in order to hold the pressure of the reservoir. It consists of a rectangular infinite aquifer, with viscosity of one cp. It was modeled using the Carter-Tracy model for infinite acting aquifers.

The aquifer is located in layers 16 to 20. It has a thickness of 500 ft and leakage was not allowed. Figure 3.2 also shows the aquifer at the last five layers of the sector. The thermal rock properties for this reservoir were compressibility equal to $1 \times 10^{-6} \text{ 1/psi}$ and porosity reference pressure equal to 1290 psi.

The reference temperature set to 150 °F. Its wetting phase was set to water wet, with no capillary pressure. Table 3.4 shows the values of water-oil relative permeability as function of water saturation.

The smoothing method for table end-points was power law or quadratic smoothing. Also, Table 3.4 shows the gas-liquid relative permeability table. Same smoothing method was used for this table. Hysteresis was not modeled in this research.

Using the relative permeability values from Table 3.4 the relative permeability curves and liquid saturation curve were created. Figure 3.5 and Figure 3.6 show the smoothed curve using power law or quadratic smoothing. The adsorption components’ composition dependence was independent of temperature. Adsorption dependence used Langmuir isotherm coefficients.
Table 3.4 Relative permeability table used to model the reservoir

<table>
<thead>
<tr>
<th>Water Saturation, $S_w$ (unitless)</th>
<th>Water relative permeability, $k_{rw}$ (unitless)</th>
<th>Oil relative permeability, $k_{row}$ (unitless)</th>
<th>Liquid Saturation, $S_l$ (unitless)</th>
<th>Gas relative permeability, $k_{rg}$ (unitless)</th>
<th>Liquid relative permeability, $k_{row}$ (unitless)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.35</td>
<td>0.000000</td>
<td>0.2000</td>
<td>0.55</td>
<td>0.020000</td>
<td>0.0000</td>
</tr>
<tr>
<td>0.37</td>
<td>0.000025</td>
<td>0.1648</td>
<td>0.63</td>
<td>0.011574</td>
<td>0.0000</td>
</tr>
<tr>
<td>0.39</td>
<td>0.000203</td>
<td>0.1340</td>
<td>0.70</td>
<td>0.005926</td>
<td>0.0000</td>
</tr>
<tr>
<td>0.41</td>
<td>0.000684</td>
<td>0.1073</td>
<td>0.72</td>
<td>0.004883</td>
<td>0.0000</td>
</tr>
<tr>
<td>0.43</td>
<td>0.001620</td>
<td>0.0844</td>
<td>0.74</td>
<td>0.003970</td>
<td>0.0004</td>
</tr>
<tr>
<td>0.44</td>
<td>0.003165</td>
<td>0.0650</td>
<td>0.76</td>
<td>0.003179</td>
<td>0.0013</td>
</tr>
<tr>
<td>0.46</td>
<td>0.005469</td>
<td>0.0488</td>
<td>0.78</td>
<td>0.002500</td>
<td>0.0031</td>
</tr>
<tr>
<td>0.48</td>
<td>0.008684</td>
<td>0.0356</td>
<td>0.79</td>
<td>0.001926</td>
<td>0.0061</td>
</tr>
<tr>
<td>0.50</td>
<td>0.012963</td>
<td>0.0250</td>
<td>0.81</td>
<td>0.001447</td>
<td>0.0105</td>
</tr>
<tr>
<td>0.52</td>
<td>0.018457</td>
<td>0.0167</td>
<td>0.83</td>
<td>0.001055</td>
<td>0.0167</td>
</tr>
<tr>
<td>0.54</td>
<td>0.025318</td>
<td>0.0105</td>
<td>0.85</td>
<td>0.000741</td>
<td>0.0250</td>
</tr>
<tr>
<td>0.56</td>
<td>0.033699</td>
<td>0.0061</td>
<td>0.87</td>
<td>0.000496</td>
<td>0.0356</td>
</tr>
<tr>
<td>0.58</td>
<td>0.043750</td>
<td>0.0031</td>
<td>0.89</td>
<td>0.000313</td>
<td>0.0488</td>
</tr>
<tr>
<td>0.59</td>
<td>0.055624</td>
<td>0.0013</td>
<td>0.91</td>
<td>0.000181</td>
<td>0.0650</td>
</tr>
<tr>
<td>0.61</td>
<td>0.069473</td>
<td>0.0004</td>
<td>0.93</td>
<td>0.000093</td>
<td>0.0844</td>
</tr>
<tr>
<td>0.63</td>
<td>0.085449</td>
<td>0.0000</td>
<td>0.94</td>
<td>0.000039</td>
<td>0.1073</td>
</tr>
<tr>
<td>0.65</td>
<td>0.103704</td>
<td>0.0000</td>
<td>0.96</td>
<td>0.000012</td>
<td>0.1340</td>
</tr>
<tr>
<td>0.73</td>
<td>0.202546</td>
<td>0.0000</td>
<td>0.98</td>
<td>0.000001</td>
<td>0.1648</td>
</tr>
<tr>
<td>0.80</td>
<td>0.350000</td>
<td>0.0000</td>
<td>1.00</td>
<td>0.000000</td>
<td>0.2000</td>
</tr>
</tbody>
</table>
Figure 3.5 Relative permeability curves to oil, water, and gas: Relationship between water saturation and relative permeability.
3.3 Polymer Injection Cases

A polymer concentration of 1000 ppm was chosen for this research. Viscosity values 10.8 cp, 15 cp, 20 cp and 25 cp were used for different simulations. Shear thinning non-Newtonian behavior was used in the model. CMG-Stars $n$-thinning of 0.8 was selected, velocity and viscosity were 9.34E-07 ft/s and 10.8 cp as shown in Table 3.5
Table 3.5 Thinning viscosity relationship with velocity

<table>
<thead>
<tr>
<th>Velocity (ft/s)</th>
<th>Viscosity, ( \mu_{app} ) (cp)</th>
<th>Shear rate (1/sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td>9.34E-07</td>
<td>10.80</td>
<td>6.79E-06</td>
</tr>
<tr>
<td>3.80E-06</td>
<td>10.58</td>
<td>2.76E-05</td>
</tr>
<tr>
<td>3.80E-05</td>
<td>6.48</td>
<td>2.76E-04</td>
</tr>
<tr>
<td>1.14E-04</td>
<td>4.86</td>
<td>8.28E-04</td>
</tr>
<tr>
<td>2.28E-04</td>
<td>4.32</td>
<td>1.66E-03</td>
</tr>
<tr>
<td>3.80E-04</td>
<td>4.21</td>
<td>2.76E-03</td>
</tr>
</tbody>
</table>

\[
\mu_{app} = \mu_p \left( \frac{u_1}{u_{lower}} \right)^{n_{thinning}^{-1}} = 10 \times \left( \frac{0.081}{0.081} \right)^{0.8^{-1}} = 10.8 \text{ cp} \tag{3.1}
\]

\[
\dot{\gamma}_{fac} = C \left[ \frac{3n_{thinning} + 1}{4n_{thinning}} \right]^{n_{thinning}^{-0.8}} = 6 \left[ \frac{3 \times 0.8 + 1}{4 \times 0.8} \right]^{0.8^{-1}} = 4.71 \tag{3.2}
\]

\[
\dot{\gamma} = \frac{\dot{\gamma}_{fac} |u_1|}{\sqrt{k / \rho_f \phi S_l}} = \frac{4.71 \times 9.34E-7}{\sqrt{68.63mD \times 0.047 \times 0.16 \times 0.82}} = 6.79E - 6 \text{ 1/sec} \tag{3.3}
\]
Using Equation 3.1 the thinning viscosity values were calculated and inputted in the model. The $n$-thinning value was assumed equal to 0.8 in order to reach the behavior showed in Figure 3.7. The shear factor was calculated using Equation 3.2. $C$ value was a constant assumed equal to six (default value). Equation 3.3 shows the calculation of the shear rate using velocity, shear factor, permeability, porosity, relative permeability and liquid saturation. With the increase in shear rate, the viscosity of the polymer mixture decreased simulating the behavior of shear thinning.

A different case was also modeled as shown in Figure 3.8. It was a combination between water injection and polymer injection with a viscosity of 10.8 cp. The treatment was divided in five injection periods, from 0 days to 219 days and so on until 1095 days (i.e., one pore volume).
were reached. The sector’s pore volume was divided as follows: 20% of the sector’s pore volume was injected with water, 20% PV was injected with polymer, 20% PV was injected with water the second time, 20% PV was injected with polymer a second time and finally the last 20% PV was injected with water.

Figure 3.8 Water and polymer combination injection case.

3.4 Initial Conditions and Geomechanics

The initial conditions for the simulation were set as follows. Vertical equilibrium calculation method used was Depth-Average Capillary Gravity Method. Grid depth range was set from 1150 ft. (top of the reservoir) to 2250 ft. Reference depth was set at 1400 ft. The water oil contact depth was 1650 ft.

Assumptions for the geomechanics of the reservoir were made in accordance to the literature about similar reservoirs. Elasto-Plastic Mohr-Coulomb rock type model was selected. Assumptions were made for the Young’s elastic modulus and Poisson’s ratio average values. As
previously stated these were carefully selected from literature (Zoback 2010) of similar reservoirs. The exact assumed average values were $E = 2.045 \times 10^6$ psi and $\nu = 0.2$. 
CHAPTER 4
RESULTS AND DISCUSSIONS

The following chapter shows the results and analysis of the numerical investigation done on the discussed reservoir, cumulative production for different polymer viscosities, comparison between the cumulative production with no injection and different injection treatments, cumulative production and production rate of the 18 production wells. Effects of the effective mean, maximum and minimum stress on the reservoir geomechanical properties are also discussed. Mohr-Coulomb failure criteria was used to identify the failure envelope. Finally, the subsidence from geomechanics on the presented reservoir.

4.1 Cumulative production comparison

First, cumulative production was evaluated for different cases. Those cases included no injection, polymer viscosity equal to 10.8 cp, polymer viscosity equal to 15 cp, polymer viscosity equal to 20 cp, polymer viscosity equal to 25 cp.

The results from the cumulative production for the different viscosity cases were compared. It was determined that the best polymer viscosity option for this study was equal to 10.8 cp. Figure 4.1 shows the behavior of the cumulative production for polymer viscosity values equal to 10.8 cp, 15 cp, 20 cp, 25 cp and natural production with no injection.
Figure 4.1 Relationship between cumulative production and time for no injection and polymer viscosity values of 10.8 cp, 15 cp, 20 cp, and 25 cp.

It was established that the polymer viscosity to use was equal to 10.8 cp. It showed the highest cumulative production. Cumulative production data from natural production and polymer injection cases was compared to establish that the treatment was working properly. As seen on Figure 4.2, the polymer injection treatment done for 10 years showed a recovery factor of 14% equivalent to 9.050 MMSTB of increased cumulative production was in place.
Figure 4.3 shows a closer look of the first 1095 days of cumulative production.

Figure 4.2 Cumulative production for the cases of no injection and polymer injection at an injection rate of 502 bbls/day and polymer viscosity of 10.8 cp for a period of 3650 days.
The cumulative production for the 18 wells was necessary to determine the behavior of the sector selected for this research. The wells found in the corners of the sector, such as P18, P15, P1 and P6, showed a higher cumulative production than the rest of the wells. The main reason is that these wells are connected to the rest of the reservoir. Oil from outside the sector was being produced. In this research the sector was not isolated from the rest of the reservoir to increase the similarity with a real project. P16, P13, P8, P4, P17, P10, P14, P3, P7, P2 showed a medium level of cumulative production. These wells were also producing oil from the rest of the reservoir.
reservoir. P12, P9 and P11, P5 showed the lower cumulative production in that order. Figure 4.4 shows the cumulative production comparison for the polymer viscosity equal to 10.8 cp for each producing well.

![Cumulative oil production graph](image)

**Figure 4.4** Cumulative oil production for the 18 wells from Sector 1 during the 1095 days of production at a polymer viscosity of 10.8 cp.

As seen in Figure 4.4, production wells P11 and P5 started producing a similar rate than other production wells. After approximately 175 days of production, the production of oil in P11 and P5 is minimum. Many factors can be causing the oil production to decrease. For this study,
the wells continued producing liquid as shown in Figure 4.5, most of the reachable oil was extracted in that part of the reservoir.

Figure 4.5 Cumulative liquid production for the 18 wells from sector 1 during the 1095 days of production at a polymer viscosity of 10.8 cp.

Even though the production wells P12, P9, P11, P5 were closer to the injection wells as shown in Figure 4.6, the oil production did not increase as the other production wells on the corners and limits of the selected sector. The polymer injection treatment fully reaches the production wells P5, P11 before most of the wells. Also, Figure 4.6 shows the displacement of the polymer reaching these two wells at approximately 395 days. Figure 4.7 shows a comparison of oil production rate from P5, P13 and P18, which have low, medium and high cumulative oil production respectively from 104 days to 504 days. There was an increased on oil production for well P13 during the mentioned period of time due to the polymer injection treatment.
Figure 4.6 Water viscosity with a value of 10.8 cp reaching wells P5, P11, P12 and P9 at approximately 395 days of polymer injection treatment.
Figure 4.7 Comparison between the oil production rate from wells P5, P13, P18 where the oil production rate of well P13 increased during this period due to the polymer injection treatment.

4.2 Water and Polymer Injection

As discussed in the methodology, a treatment of water injection and polymer injection was modeled. Figure 4.8 shows the comparison of the oil production rate with no injection, 100 % polymer injection and the combination of water injection and polymer injection. As clearly defined in Figure 4.8, the water injection and polymer injection combination treatment was the most successful for this sector of the reservoir.
Figure 4.8 Comparison between the oil production rates of the selected sector. No injection, 100% polymer injection and water-polymer injection.

The polymer injection treatment improves the oil recovery during the water injection. As seen in the green line, there was more oil production using the combination of water and polymer. Also in some periods the oil production rate of the polymer injection treatment goes over the natural oil production rate, mainly because of the increase of the oil saturation due to efficient displacement.
4.3 Effective Mean Stress, Maximum and Minimum Stress

The main objective of this research is to study the effects of polymer injection in the geomechanical properties of the reservoir. The first variable studied was the effective mean stress (EMS) for the cases of no injection, water injection and 100% polymer injection. Different subcases were studied in order to understand the effects of the two types of treatments in the reservoir geomechanics.

Figure 4.9 Effective mean stress comparison between the case of no injection and polymer injection case with viscosity equal to 10.8 cp at 90 and 182 days.
The first layer of the selected sector was the most affected by the effective mean stress as shown in Figure 4.9. For the first 365 days it was clear that the EMS values were higher in the upper and lower part of the sector. It is clear that the behavior of the EMS in the case of no injection remains similar through the entire time. On the other hand, the behavior changes in the case of polymer injection with the change in time. Comparing the behavior in the middle section of the depth interval, for 365 days (Figure 4.10) and 1095 days (Figure 4.11), a clear increase on the EMS values was found.

Figure 4.10 Effective mean stress comparison between the case of no injection and polymer injection case with viscosity equal to 10.8 cp at 365 and 546 days.
Figure 4.11 Effective mean stress comparison between the case of no injection and polymer injection case with viscosity equal to 10.8 cp at 728 and 1095 days.
Effective means stress was compared using water injection and polymer injection at the same time. Figure 4.12 shows the results for the effective mean stress at different layers. The first layer is the most affected by the injection. The average permeability is equal to 19.73 md for layer one. Also, the average porosity is equal to 0.13 for the same layer. The effective mean stress is higher than any other layer.

Figure 4.12 Comparison between the effective mean stress for each 15 layers at 182 Days with different injection treatments.
Figure 4.13 Comparison between the effective mean stress for each 15 layers at different times: (a) 365 days; (b) 546 days with different injection treatments.
Even though for the water injection case the first layer effective mean stress value is greater than for polymer injection as shown in Figure 4.13 and Figure 4.14, the rest of the layers behave similarly and show most of the time a smaller value of effective mean stress than for polymer injection. In the region from layer three to layer 11, the average porosity values increased with depth. High porosity value allows higher water saturation and pore pressure value increases. According to Equation 4.1, when the pore pressure value increases, the effective mean stress decreases.

\[
\sigma_{\text{eff}} = \sigma_v - \alpha P_p 
\]  

\[(4.1)\]

---

Figure 4.14 Comparison between the effective mean stress for each 15 layers at 728 days with different injection treatments.
From the results given by the last four figures, and in harmony with the purpose of this research, the decision of working with the case of 100% polymer injection was made. The next variables will be evaluated only for the case of 100% polymer injection. Different viscosities were also discussed in order to complement the cumulative oil production study.

Oil production rate was studied for each of the critical layers; layers 1, 3, 5 and 10 were selected. Using a sample of three production wells, P5, P13 and P18 oil production was compared. These three wells are low, medium and high production wells.

Figure 4.15 Comparison between the oil production rate for P5 well layers 1, 3, 5 and 10 at a range of 300 days.
Results shown in Figure 4.15 clearly state that the production is affected by the permeability of the layer. Layer 1 and 3 have similar average permeability values. Oil production shows similar trends for these two layers in Figures 4.16 and 4.17 as well. For production well P5, layer 10 shows a high production from start. After less than a 100 days, production goes down to minimum rate. Being layer 10 a high permeability layer, the polymer sweep efficiency increases and most of the oil is produced due to the fact that P5 is close to two of the injection wells INJ2 and INJ1.

Figure 4.16 Comparison between the oil production rate for P13 well layers 1, 3, 5 and 10 at a range of 300 days.
Finally, Figure 4.18 shows that after approximately 10 days the injection rate on layer 10 presents the highest value below 80 bbl/day throughout the 1095 days. Figure 4.19 shows a similar trend for injection, in this case a little above 75 bbl/day. Also, Figure 4.20 shows for layer 10 a steady trend above 80 bbl/day. As there is a higher injection rate for layer 10, compared to one, three and five, the pore pressure increases explaining the decreasing behavior of the EMS around the high permeability layers of the sector.

![Figure 4.17 Comparison between the oil production rate for P18 well layers 1, 3, 5 and 10 at a range of 300 days.](image-url)
Figure 4.18 Polymer injection rate for layers one, three, five and eleven from injector one.

Figure 4.19 Polymer injection rate for layers one, three, five and eleven from injector two.
In summary, the effective mean stress affects the low permeability layers. Also, high polymer injectivity in the middle depth layers makes the pore pressure increase causing the EMS values to be lower in that part of the formation. Low polymer injection rates increase the effective mean stress in the layers with lower permeability and lower porosity (layers 1, 2, 3 and layers 12, 13, 14 and 15).
Particularly, the pore pressure decreases because of the oil being swept slowly by the treatment making the EMS increase. Also, pore pressure increases by the polymer injection in the high permeability layers, which causes a decreasing trend around those layers. Two more variables were used to evaluate the effects of the polymer injection case. Maximum and minimum stress affecting the sector were evaluated. Also, this data was useful to continue with the Mohr-Coulomb failure criteria.

Once the results of the simulation were studied, a comparison was made between different polymer viscosities and the maximum and minimum stress. Figure 4.21 showed that the maximum stress decreases when viscosity increases. If the polymer mixture is more viscous, the less stress causes in the formation. This figure also corroborates the usage of polymer viscosity of 10.8 cp. as the chosen viscosity.

![Figure 4.21 Comparison between the maximum and minimum stress with polymer viscosity.](image)
Selecting the higher maximum stress values was necessary to better study the changes caused by polymer injection. Layer one shows the higher values of minimum and maximum stress. This layer was the most affected by the oil production and the polymer injection as shown in Figure 4.22. Also, both minimum and maximum stress have similar trend throughout the sector.

Figure 4.22 Relationship between the stress and sector’s depth: (a) Maximum stress; (b) Minimum stress with polymer viscosity.
4.4 Mohr-Coulomb Failure Criteria and Subsidence

Using the maximum and minimum stress values from Figure 4.21, the linearized Mohr-Coulomb failure criteria was done. It assumes that the intermediate principal stress does not influence rock failure. Only maximum and minimum stress will be used. As previously stated, the reservoir studied in this research was a sandstone reservoir. From Figure 4.23 the cohesion for a sandstone reservoir with similar characteristics was selected using average porosity for the sector $\phi = 0.16$, $C_0 = 30 \text{ MPa}$. The coefficient of internal friction was read from Figure 4.24, $\mu_i = 1.1$ (unitless).

Figure 4.23 Relationship between cohesion and porosity for a sandstone reservoir (Fjaer et al. 2008).
Figure 4.24 Relationship between coefficient of internal friction and type of reservoir rock (Zoback 2015).
Using Equations 4.2 and 4.3 and the values read from previous figures, the maximum stress necessary to cause rock failure was calculated.

\[
C_o = 30 \text{MPa} \times \frac{145.04 \text{ psi}}{1 \text{ MPa}} = 4,351.14 \text{ psi} \tag{4.2}
\]

\[
q = \left[ \left( \mu_i^2 + 1 \right)^{\frac{1}{2}} + \mu_i \right]^2 = \left[ (1.1^2 + 1)^{\frac{1}{2}} + 1.1 \right]^2 = 6.50 \text{ (unitless)} \tag{4.3}
\]

\[
\sigma_1 = C_o + q\sigma_3 = 4,351.14 \text{ psi} + 6.50 \times 280.22 = 6,172.04 \text{ psi} \tag{4.4}
\]

The maximum stress needed to be outside the failure envelope is shown by Equation 4.4. The difference between the obtained value in the simulation, maximum stress caused by polymer injection showed in Figure 4.21, and the calculated maximum stress to pass the failure envelope was very high. In summary, the polymer injection at the selected rate, concentration and viscosity will not cause any rock failure to the reservoir’s sector.

The subsidence from geomechanics values are not high. An average of \(7 \times 10^{-3}\) to \(10 \times 10^{-3}\) ft was found at layer 10. Figure 4.25 shows that there is a high subsidence value in the first layer, relative to the rest of the layers.

The subsidence may be caused by the depleted sector and the aquifer contributing to the compaction of the reservoir. In this case, the higher value reached by the layer 1 was 0.0092 ft, which is negligible compared to the reservoir thickness.
Figure 4.25 Subsidence from geomechanics 1095 days after polymer injection.
CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

Polymer injection effects on the geomechanical properties of the reservoir were successfully studied in this research. A sandstone reservoir sector was modeled using reservoir simulation commercial software. The effective mean stress, maximum and minimum stresses and subsidence changes induced by the polymer injection were modeled and studied for this particular sector of the reservoir. The following conclusions were generated from this research:

• The best case for polymer injection for the sector of this reservoir was a combination treatment between water and polymer injection. A second case with 100% polymer injection was the main treatment used for the results of this research.

• Polymer injection decreases the mobility ratio and increases the sweep efficiency causing an increase in oil production. The polymer concentration that best works for this treatment was 1,000 ppm with a viscosity of 10.8 cp and an injection rate of 502 bbl/day per injector.

• The effective mean stress values during the polymer injection changed with time. Every layer behaves differently depending on its porosity and permeability. The higher permeability layers were able to see fewer changes in the effective mean stress. Lower permeability layers showed higher effective mean stress changes. Particularly, layer one was the most affected with higher changes of effective mean stress and layer 10, which had the highest average permeability, shows a larger decrease in effective means stress.
• The maximum and minimum stresses showed the same behavior depending on the reservoir permeability and porosity. The Mohr Coulomb criteria was used to calculate the failure envelope for this particular sector of the reservoir. For a minimum stress value of $\sigma_3 = 280.22$ psi located at layer one, the maximum stress calculated to cause formation damage was $\sigma_1 = 6,172.04$ psi.

• The highest value of maximum stress was $\sigma_1 = 815.44$ psi, which did not fall outside the failure envelope. The highest subsidence value was 0.0092 ft. The most affected layer of the sector was layer one. The subsidence was very small compared with the area of the sector and its thickness. Subsidence was considered negligible for this study.

• Changes in stress affected the permeability of the selected reservoir’s sector. These changes affected the production of rate of the wells closed to the injectors. The production of the wells at the corner of the sector was not as affected as the production of the inside wells.

In future studies, more data is necessary to generate accurate results. Less assumptions can be made if more data is available. Production data is also necessary to do history matching and forecasting. Instead of using average permeability, porosity, Young’s Modulus and Poisson’s Ratio data, raw data will generate more accurate results on this type of study. A comparison with an experimental study of a sample of this reservoir would be useful to corroborate all the assumptions that were made. A study for carbonate reservoirs and unconventional reservoirs...
would give a chance to determine the effects of polymer injection their geomechanical properties.
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