Reservoir Geomechanics Model for EGS

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ABSTRACT

This paper presents a workflow for geomechanics reservoir characterization (also known as a MEM) for geothermal reservoir development. A geomechanics model is very useful for all aspects of reservoir development including drilling and stimulation. The modeling effort begins by synthesizing various types of data from available wells. These include well logs, lithologic data and lab data. The result for each is a so-called 1D MEM and provides useful information in making decisions during drilling. However, isolated well data fail to capture the 3D variability of geomechanical properties that affect EGS reservoir development plans. Therefore, the 1D data are integrated to build a 3D model of the reservoir. The main components of a 3D model are structural features of the reservoir, stratigraphy, 3D simulation grid, wells, 3D interpolated rock data volumes and in-situ stress estimates. Since in an EGS reservoir, permeability is created by fractures, a discrete fracture network (DFN) is generated based off well log data. Any faults present in the area should be included. Faults are interpreted from seismic data or estimated based on their strike and dip at the surface. Since an EGS reservoir is typically much smaller than a conventional oil reservoir, making a 3D model is not as computationally intensive. However, if enough data is available and the reservoir contains a large amount of heterogeneity, a smaller cell size would be better and computing power is a consideration. Wells are defined in the model if they have core or log data or if they have environmental implications. In EGS, wells are very limited so that 3D seismic and geological investigations can be called upon for reservoir data regarding stress and structures. As a simple example of this workflow, the proposed FORGE site at the Idaho National Laboratory will be used to make a 1 km x 1 km 3D geomechanics model.

1. Introduction

Reservoir characterization has become commonplace in the oil industry to reduce uncertainty and select optimal drilling locations and trajectories. Conventional reservoir models consist of structural models integrated with a 3D grid which is then populated with reservoir properties such as rock type, oil saturation, porosity and water saturation. As the oil industry has grown increasingly aware of the effect of mechanical properties such as stress magnitudes, stress direction, permeability, density and rock strength on well planning and reservoir stimulation, conventional reservoir characterization has been adapted to create reservoir geomechanics models. A reservoir geomechanics model (also known as an MEM) is a small scale (reservoir scale) 3D geomechanical description of the reservoir. It consists of a structural geologic model integrated with a 3D grid populated with mechanical data and stress estimates. In highly fractured petroleum reservoirs, a discrete fracture network (DFN) must be coupled with the MEM (Spence et al., 2014).

Currently, MEMs are being successfully used in the oil industry to make decisions concerning drilling directions, mud selection and casing interval depth (Afsari et al., 2009 and Plumb et al., 2000). MEM’s also provide valuable infor-
mation on how a reservoir will respond to stimulation (Spence et al., 2014). Outputs from MEM’s such as friction angle, permeability, stress estimates, rock strength and the coupled DFN are used as inputs to fracture models which enable further characterization of reservoir stimulation and reduce risk (Spence et al., 2014, Barton et al., 2013). As EGS increasingly becomes a reality, the need for similar methods of mechanical characterization of EGS systems is essential. However, costs and lack of well data pose challenges. Nevertheless, the same outcome may be achieved using less costly approaches and alternate sources of data. The main issue is the recognition that the geomechanical features and properties ought to be an integral part of effective reservoir characterization.

Past experiments such as Fenton Hill and Rosemanowes have shown that the response of crystalline basement rocks to stimulation differs from sedimentary rocks (Brown et al., 2015 and Tester et al., 2006). Whereas sedimentary rocks tend to fracture in manners which are predictable based on the in-situ stresses, basement rocks with pre-existing fracture networks tend to be stimulated by reactivation of open or healed joints in a more complex fashion (Brown et al., 2015; Pine and Batchelor, 1984). An understanding of the joint pattern through multiple realizations of a DFN (Barton et al., 2013), would contribute greatly to reducing the risk associated with stimulation in crystalline basement containing healed fractures. In-situ stress estimates and geomechanical properties are also important since the stresses dictate which fractures open and in what directions they propagate. EGS sites can also bring very inhospitable drilling conditions not normally encountered by experienced oil drillers. Proceedings at Fenton Hill demonstrated this when zones of cavernous limestone that were severely under pressured were encountered causing expensive delays and numerous unsuccessful cementing operations (Brown et al., 2015). An MEM could help with managing the risk associated with planning and drilling the wells. This paper presents a generic workflow for creating an MEM and an associated DFN which can aid in making decisions and addresses some of the risks associated with drilling and stimulating geothermal systems.

2. Relevant Data Needs and Techniques for Their Estimation

Stress estimates are done using two primary methods: the theory of elasticity and faulting theory. The vertical stress component can be estimated by assuming lithostatic conditions. Then a density log can be used to calculate its magnitude. The determination of the other two components namely Shmin and SHmax are more challenging and uncertain. The Shmin value usually is obtained from leak-off tests, or mini-frac tests (Ghassemi, 2012). These tests can be challenging and costly so alternative methods are needed such as rock failure theory to establish bounds on the horizontal stress magnitudes.

2.1 Faulting Theory

In tectonically active regions, faulting theory applies the Mohr Coulomb criterion. Rock fracture or faulting theory (Jaeger et al., 2009) can be applied (Moos and Zoback, 1990) to provide a lower bound to the minimum principal stress or an upper bound to the maximum principal stress.

\[
\frac{\sigma_v - P_p}{\sigma_h - P_p} = \left(1 + \mu^2\right)^{\frac{1}{2}} + \mu
\]

The assumption is that in tectonically active regions, the stresses can be constrained by determining the minimum horizontal stress needed to cause rock failure. The stress differential necessary to cause failure in the normal faulting regime is the lower bound of the minimum principal stress. \( \mu \) is the friction and usually taken to be 0.6 (Moos and Zoback, 1990). \( \sigma_v \) is the vertical (and the major ) principal stress. \( P_p \) is the pore pressure usually taken to be hydrostatic in the absence of other data. \( \sigma_h \) is the minimum principal stress. Rock strength is assumed to be zero since in a faulted rock failure has already occurred. Friction dominates resistance to slip. Using these inputs, a fast answer can be found for the minimum principal horizontal stress. After a value of \( \sigma_h \) has been determined, the kirsch solution can be used to estimate a value for the maximum horizontal stress \( \sigma_H \) if hydraulic fracture data is available. On the other hand breakouts or their absence may be used to establish bounds on SHmax. Alternatively, one can infer that for a normal regime the possible values of SH max are in between the vertical and least horizontal stress values. As a rule of the thumb, Shmin is approximately \( \frac{1}{3} \) of the vertical stress. Placing SHmax between Shmin and the vertical stress allows us to approximate SHmax as \( \frac{2}{3} \) of the overburden.

2.2 Interpretation of Breakouts Using Elasticity Theory

The presence of breakouts and tensile fractures in the wellbore is used to determine the orientations of the horizontal in-situ stresses (Sh, SH) and to constrain their magnitudes. The Kirsch (1898) solution provides an expression for the effective tangential stress around a wellbore in terms of Sh and SH:
\[
\sigma_{\theta\theta} = \sigma_{\text{hmin}} \left[ \left( 1 + \frac{\sigma_{\text{HMax}}}{\sigma_{\text{hmin}}} \right) + \left( 1 - \frac{\sigma_{\text{HMax}}}{\sigma_{\text{hmin}}} \right) 2\cos(2\theta) \right] - \alpha P_{\text{pore}} - P_{\text{well bore}}
\]

The angle, \( \phi \), is measured counter clockwise from the greatest principal stress in a wellbore cross section. The overburden is assumed to be a principal stress whose axis is the wellbore. Wellbore pressure \( P_{\text{well bore}} \) is assumed to be the same as the pore pressure \( P_{\text{pore}} \) so that the effective radial stress at the wellbore wall is zero. The Biot coefficient, \( \alpha \), for failure analysis is taken to be 1. The tangential stress can be compressive or tensile. In the former case the rock will fail in shear if \( \sigma_{\phi\phi} \) is larger than the uniaxial compressive strength. In the later the rock at the wellbore will fail in tension if the tensile strength is exceeded. The uniaxial compressive strength \( C_{\text{uniaxial}} \) and the tensile strength \( T \) must be determined experimentally in the laboratory or derived from well log correlations.

By replacing \( \sigma_{\phi\phi} \) with the appropriate rock strength or allowing \( \phi \) to be 90° (the azimuth of the minimum principal stress), the potential for breakouts to occur or the stress ratios may be solved for depending on the available data. If data from a fracture test is available, the stresses can then be solved for using the ratio. If no breakouts or tensile fractures are visible in borehole image logs and no fracture tests constrain the least horizontal stress, this equation can be used with the tensile and compressive rock strengths (determined in the lab or values taken from similar rock samples) as input to generate a system of equations which can then be used to constrain the horizontal stresses (Brady and Brown, 1985; Moos and Barton, 1990):

\[
\sigma_{\theta\theta,\text{Max}} = 3\sigma_{\text{HMax}} - \sigma_{\text{hmin}} - \alpha P_{\text{pore}} - P_{\text{well bore}} \geq C
\]

\[
\sigma_{\theta\theta,\text{Min}} = 3\sigma_{\text{hmin}} - \sigma_{\text{HMax}} - \alpha P_{\text{pore}} - P_{\text{well bore}} < -T
\]

These equations can be solved together as a system placing constraints on the magnitudes of the horizontal stresses.

2.3 Determining Stress Orientations

The overburden is taken to be a principal stress whose axis is vertical. For a vertical wellbore then, the principal horizontal stresses lay in the plane of a cross section. If drilling induced breakouts or tensile fractures are visible in image logs, these can be used to characterize the stress directions. Based on the Kirsch solution, a drilling induced tensile fracture appears at the azimuth of the maximum horizontal stress while breakouts appear at the azimuth of the least horizontal stress. Other methods using well logs are available such as using the crossed dipole sonic log to determine stress orientations. If no means to calculate the stress directions at the wellbore are available, then regional stress directions can be used.

3. Workflow

1. Data Audit and model set up

Before starting the modeling effort, the data is audited to make sure all the necessary information is included in the database. If key data such as laboratory rock strength tests are unavailable, extra studies, references and assumptions are necessary to fill in the gaps. Units in the model should be decided based on the available data. Well heads and well paths, well logs, seismic survey and fault data can be imported into most 3D modeling software in proper formats. If a seismic survey is available, the coordinate reference system should be chosen to exactly locate the wells and seismic survey. Well depth calibration is a necessary procedure to correct the log data depth deviation which is caused during drilling and logging. Commonly, Gamma ray logs can be calibrated with the Gamma ray from core data.

2. 1-D Mechanical Earth Model (MEM)

Construction of 1-D MEMs is the first step to generate a 3-D distribution of a reservoir’s geomechanical characteristics (or a 3D MEM). In a 1-D model, the geomechanical properties and stresses are described along individual wellbores. In this step, overburden, pore pressure, rock strength, elastic properties and in-situ stresses are calculated with the well log data. The available lab data can be used to calibrate well log correlations for relating sonic logs to rock strength and elastic properties e.g. Najibi et al. (2015), Wang (2000), Oyler et al. (2010) and Plumb et al. (2000).

3. Lithologic al Distributions

Here, the concept of mechanical stratigraphy must be applied (Spence et al., 2014). This means that rock units must be separated based on their mechanical properties as well as the geological unit. Usually, in a sedimentary basin, the mechanical stratigraphy and geological units coincide. However, in the crystalline basement rocks where less distinct
geological boundaries are present, this concept must be applied. The boundaries between the stratigraphic units are chosen on each well by displaying a cross section of wells and grouping geological and mechanical properties. Gamma ray, spontaneous potential, photo–electric and porosity logs in addition to core descriptions and rock properties from the 1-D MEMs from each well should be compared and analyzed to correlate the structural boundaries. The boundaries are then correlated with other wells and used to make a grid of cross sections defining the structure of the area. Based on the points picked in the wells at the structural boundaries, surfaces of the formations are made.

4. Structural Framework

In this step, the structural model created in the previous step is populated with a 3D grid which is used for static reservoir simulation. The grid sizes in the horizontal and vertical directions are decided based on the reservoir scale, variability and the smallest features that need to be captured. Some software such as Schlumberger’s Petrel offers multiple gridding methods depending on whether or not faults are present in the model. Similar features are available in JewelSuite. Faults are picked on seismic data or projected to depth using their surface expressions. Commercial modeling software typically allows the horizontal cell dimensions to be selected as a grid of constant dimension cells. Local grid refinement can be applied if necessary. The vertical dimensions are often selected by using some sort of layering scheme within geologic units (Yarus and Chambers, 2006). An example of a common layering scheme is a “proportional” layering scheme meaning that all along the unit the vertical height of each cell will be the same in the vertical direction, but there is lateral variability to the cell heights. In some situations, consideration should be given to the available computing power when selecting the cell size.

5. Property Modeling

Facies modeling is a crucial part of a conventional oil reservoir model since oil reservoirs can be more complex geologically. Since the target reservoir for an EGS system is the granitic crystalline basement, there will not be the same need to model the variability of the rock type. However, for drilling and wellbore stability purposes, facies models can be useful in the upper sedimentary regions. Facies models are generated using geostatistical methods such as Sequential Indicator Simulation. Variogram ranges are used as inputs. The variogram is an important tool in 3D static reservoir simulation since it provides the correlation distances for the rock types and properties being modeled. These distances are called ranges and are used as inputs for most geostatistical algorithms used in interpolation and modeling (Gringarten and Deutsch, 2001).

Petrophysical and geomechanical properties are populated within the 3-D reservoir grid with petrophysical modeling algorithms using variograms and the 1-D MEMs as inputs. If necessary depending on whether or not a Facies model is used, the petrophysical and geomechanical modeling effort can be constrained to a specific rock type. The Kriging algorithm is an example of one potential method used to interpolate the rock properties in this model. Kriging, a deterministic simulation, is an estimation technique that uses the variogram to express the spatial variability of the input data. The horizontal and vertical variograms are both necessary for this method. Other stochastic methods are available as well such as Sequential Gaussian Simulation.

The modelling results need to be quality controlled after the calculations. They can be compared with the original log data and upscaled logs and if necessary the generating algorithm’s inputs can be adjust to obtain better model results.
6. In-Situ Stress Estimation

The magnitudes of in-situ stresses are calculated along the wellbores using the equations and methods in section 2 above, with the rock properties from the model generated in the previous step (step 5: property modeling). The directions of the maximum and minimum horizontal stresses are determined using the methods outlined in section 2. The in-situ stress magnitudes can be calibrated with hydraulic fracturing data and the in-situ stress directions can be calibrated with the drilling induced fractures from borehole image logs if available. Finally, the 3-D stress tensor is combined, interpolated across the reservoir volume using a deterministic method to model the variability and plotted.

7. Discrete Fracture Network (DFN) Modeling

The fracture network at reservoir depths is important to predict EGS reservoir behavior and do geomechanical reservoir characterization for the geothermal reservoir development. So DFN modeling is presented.

EGS reservoirs will always be in crystalline basement rock where the permeability is very low and the temperatures are high enough. However, the crystalline rocks in the basement have exceedingly high compressive and tensile strengths on the order of 170 MPA UCS and 20 MPA tensile strength (Wang et al., 2016-Geothermics; Bakshi et al., 2016). Crystalline rocks always have pre-existing sealed fracture networks with joint reopening tensile strengths and cohesion less than those of intact rock (Brown et al., 2015). Because of this, the pre-existing fractures play an important part in geothermal reservoir stimulation. The DFN helps to characterize the role the fracture network plays. Since rock matrix permeability measurements from deep crystalline rocks are on the order of microdarcys (Bakshi et al., 2016) virtually all the permeability will be derived from stimulation of the fracture network. In order to create the DFN data from reflection seismic surveys, borehole image logs, core analysis and vertical seismic profiles is brought together (Spence et al., 2014) to characterize the fracture populations present and the dimensions of the fractures. Once the data has been analyzed for the fractures present, stochastic or deterministic modeling approaches may be used.

The data gathered about the fracture populations can be used in the stochastic approach to determine the model which the fracture population fits (i.e., log normal, exponential etc.). The model along with measured aperture, intensity measurements and estimates for the aspect ratio of the fractures are used as inputs to generate multiple realizations of the DFN (Barton et al., 2013). The fracture models can then be applied to make decisions about where to locate the reservoir and what wellbore trajectory would optimize fracture stimulation (Barton et al., 2013).

4. Example

As an example of this workflow, a simple reservoir geomechanics model of the proposed FORGE laboratory site at the Idaho National Laboratory will be constructed. The Idaho National Laboratory proposed FORGE site lies near Arco, Idaho at the southern base of the Lost River Range and the northern edge of the Eastern Snake River Plain.

4.1 Data Analysis and Audit

Data were gathered from four separate wells on the Eastern Snake River Plain to generate the geomechanics model: INEL-1, WO-2, Corehole 2-2A and Middle 2050A. Types of data available were well logs and laboratory tests. Relevant well logs available were porosity, density and sonic slowness. Permeability, Poisson’s ratio, Young’s modulus, friction angle, cohesion and uniaxial compressive strength were found at specific depths through lab tests (Bakshi et al., 2016). Previous dynamic measurements from INEL-1 and Corehole 2-2A (DeVan and Martin, 1989) were used as well. The available lab data was checked for consistency with the well log data when possible.

4.2 1-D Mechanical Earth Model

Correlations (Wang, 2000) were applied to the available logs to obtain geomechanical properties along the INEL-1 wellbore. The correlations were calibrated with the lab data.

4.3 Lithologic Descriptions

A structural geologic model was created for the surrounding region based on geologic well logs, refraction data (Pankratz and Ackermann, 1982), resistivity data (Zohdy and Stanley, 1973) and cross sections (St. Clair et al., 2016). The geology of the area is believed to be defined by the Picabo caldera system generated by the Yellowstone Hotspot (Anders et al., 2014). The mechanical stratigraphy was determined to coincide with the geology. The structural model was then cropped down to the desired 1 km by 1 km aerial extent and used to make the MEM.

4.4 Structural Framework

A 3D simulation grid was created using the structural surfaces displayed in Figure 2. The grid horizontal dimensions were 500 m x 500 m since only one 1-D MEM existed to extrapolate. Vertical cell thickness selected was 10 m since
greater vertical resolution was available. Computing power was not a concern.

4.5 Property Modeling
Since for each depth value, only 1 data point existed across the model, Krigging was used as the interpolation algorithm with horizontal variogram ranges large enough to distribute the single value throughout the layers. Vertical variogram values based on the data were selected to fill in layers without data.

4.6 In-Situ Stress Estimation
After the model had been generated, the values at the reservoir depth of 10,000 ft were extracted from the MEM and used to estimate the stresses by applying the Kirsch solution. The pore pressure is assumed to be brine calculated from data gathered by Mann (1986) and calculated to be 3,976.5 psi. The overburden stress is calculated from integrated density logs and was found to be 11,237 psi.

Rock compressive and tensile strengths are taken to be the nearest available lab values of $C = 25,991$ psi and $T = 2,793$ psi (Bakshi et al., 2016) measured at 10,365 ft. Effective stress with $\alpha$ is assumed to prevail. The value $\alpha = 1$ is chosen based on resistivity logs from INEL-1 which show very low resistivity (Moos et al., 1990). No drilling induced breakouts or tensile fractures are visible on the image logs from INEL-1 (Moos and Barton, 1990). Applying the kirsch equations to constrain the stresses and substituting our values we get:

$$3\sigma_{\text{HMax}} - \sigma_{\text{hmin}} - 3,976.5 - 3,976.5 \geq 25,991 \text{ psi}$$

$$3\sigma_{\text{hmin}} - \sigma_{\text{HMax}} - 3,976.5 - 3,976.5 < -2,793 \text{ psi}$$

This system can be solved together to give bounds for the horizontal stresses:

$$\sigma_{\text{HMax}} < 13,374 \text{ psi}$$

$$\sigma_{\text{hmin}} \geq 6,178 \text{ psi}$$

Since the Eastern Snake River Plain is assumed to be a normal faulting regime (Moos and Barton, 1990), $\sigma_1 = \sigma_y$, $\sigma_2 = \sigma_H$ and $\sigma_3 = \sigma_h$. A low stress differential is assumed to be the case given the low frequency of seismic events (Moos and Barton, 1990). Based on these assumptions, $\sigma_h$ is taken to be around 6,400 – 6,500 psi (slightly above the lower bound) and $\sigma_H$ is taken to be slightly higher from 7,000 – 8,000 psi. The direction of maximum horizontal stress is taken to be at an azimuth of 152° based on the regional direction of maximum horizontal stress surrounding the plain. The stress estimate was then input into the MEM and plotted as a 3D tensor at the reservoir depth of 10,000 ft.

4.7 Discrete Fracture Network (DFN) Modeling
Approximately 4,000 ft of fracture data was available in the INEL-1 well (Moos and Barton, 1990). However, the data is for an interval above the target reservoir and many kilometers from the actual drill site. The rose diagram in figure 3 indicates the presence optimally oriented fractures (perpendicular to the minimum horizontal stress).
The data fit a log normal model best and was used to generate a DFN (figure 4) to analyze possible networks of fractures near to failure.

5. Discussion

5.1 Key Points

A reservoir geomechanics model requires the integration of multiple disciplines. It is very important to start with the correct geologic model framework to create the mechanical stratigraphic framework. Special attention must be paid to the grid scheme. In many sedimentary reservoirs, truncated or folded stratigraphy can be present in a single geologic unit. If this is the case, consideration should be given to the trend of the mechanical properties within that unit. Since EGS reservoirs tend to be in more homogenous rock masses with regard to their properties, this should not be a very big issue.

Correlating rock strength values from sonic logs can be tricky. Most available literature on the subject study correlations in mines or petroleum reservoirs as do Najibi et al. and Oyler et al. (Najibi et al., 2015 and Oyler et al., 2010), not crystalline basement EGS reservoirs. While a general correlation does exist, it must be remembered that the lab values used to calibrate the correlations are the only values known with certitude. The correlated values should be taken as an indicator of the general trends of the properties and their variabilities.

Stress estimates can be done in several ways. If borehole image logs are available it may be beneficial to apply both the kirsch solution and faulting theory. A comparison of the two methods can help to constrain stress estimates.

5.2 Different Methods of Performing the Workflow

This workflow can be accomplished using any reservoir modeling software. Schlumberger’s Petrel and Baker Hughes’s Jewelsuite are two excellent commercial software packages that are capable of applying this workflow with ease. 1D MEMs can be easily generated in Microsoft Excel or Matlab. Interpolating the 1D MEMs though would be much easier with a reservoir modeling software package with built in geostatistical algorithms.

5.3 Limitations of a 3D Reservoir Geomechanics Model

Since EGS reservoirs are in the crystalline basement rocks, there is frequently no or very little well data available initially. To make up for the lack of core and well log data, 3D seismic surveys and data from analogous reservoirs can provide initial insight to a reservoir geomechanics model.

While a 3D reservoir geomechanics model provides useful information about reservoir trends, it must be remembered that there is uncertainty associated with the geostatistical algorithms. In order to compensate for this, multiple realizations of the same data set can yield valuable information about the local and global distributions of the mechanical properties.

It must not be forgotten that many of the values in the model are correlated from well logs. The inherent uncertainties associated with correlating mechanical properties from sonic and other logs can lead to anomalous spikes in the data. These values must be either removed from the logs prior to interpolation or the values extracted from the 3D model for inputs to fracture models must be conditioned to remove any unrealistic spikes.

In order to further condition the log correlations, more lab data or prior information about the specific field or type of rock can be applied to help constrain the range of values.

6. Conclusion

This paper presents a workflow to create a reservoir geomechanics model for an EGS reservoir in an effort to demonstrate how it can be done and to emphasize the importance of such a model. A preliminary reservoir geomechanics model can be created with very little actual data and effort. Well logs can be used to derive almost all of the geomechanical properties. Calibrated against lab tests, the well log correlations give an excellent idea of regional trends.
A discrete fracture network is very important to understanding how an EGS reservoir will develop and where to place the reservoir. Stress direction and magnitude estimates are straight forward and can offer a significant amount of information on how the fractures in the reservoir will behave under stimulation.

The benefits of a reservoir geomechanics model are enormous compared to the effort needed to create one. Large amounts of time and money can potentially be saved in drilling and stimulation efforts if reservoir geomechanics models are applied to EGS reservoirs.

References


