

Geo-mechanical modeling for tight reservoirs-A case study in Chhatral unit of Gamij area, Cambay

Basin

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Keywords

Pore pressure, Fracture pressure, Horizontal stresses

Summary

Knowledge of pore pressure, horizontal stress orientation and rock mechanical properties are essential for wellbore stability and designing of hydro fracture job in a hydrocarbon reservoir. These parameters become more important in case the reservoir exhibits low porosity with low permeability as drilling and production from such tight reservoirs becomes difficult. This paper aims to develop a 1-D MEM for tight reservoirs. Chattral pay of Gamij field has been taken up for this study as this unit has moderate porosity (15-20%) and low permeability.

The pore pressure, overburden pressure, fracture pressure, drilling fluid pressure, minimum and maximum stress magnitude and Safe mud weight window have been estimated in Chattral pay of Cambay shale using log data such as resistivity, sonic, gamma and density. Stress magnitude and direction have been estimated from sonic and formation image logs.

Based on this study 1-D MEM for Chattral pay of Gamij field has been prepared by integrating data from different sources like, log data, drilling data, and testing data. Estimated pore pressure and fracture pressure for 1D-MEM show good match with MDT and LOT of nearby wells. The developed model should prove immensely helpful for providing the necessary inputs for safe drilling and planning of HF jobs in future wells in the area.

Introduction

Gamij field is located on the raising eastern margin of Ahmedabad–Mehsana tectonic block of Cambay basin. The Chhatral pay developed within Cambay Shale of Gamij field during Middle Eocene to Lower Eocene. It consists of shale and silty shale along with intercalations of sandstone with moderate porosity

(15-20%) but very low permeability indicated tight nature of reservoir.

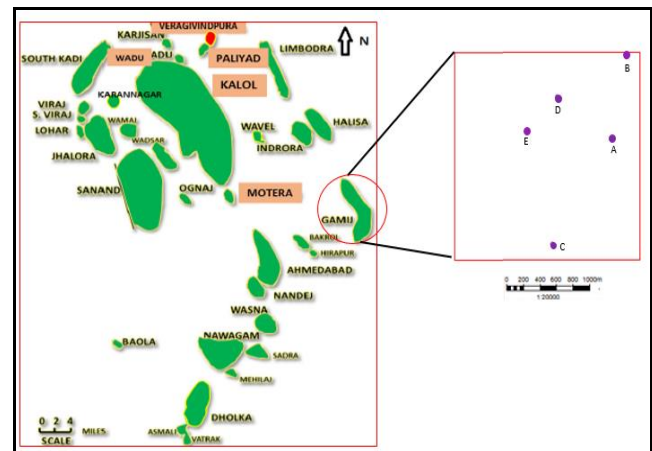


Figure-1: Gamij field map with study area and distribution of study wells.

To assess Chhatral pay at commercial level, require hydro-fracturing for production of hydrocarbon. In the present paper, an attempt was made for analyzing stress distribution in the chhatral pay of Cambay Shale reservoir. For a better understanding of the parameters causing wellbore instability and to predict mud weight window for planned wells, construction of robust Mechanical Earth Model (MEM) is essential. 1D MEM comprises of different sources of data including, pore pressure, elastic properties (Poisson's ratio, Young's modulus, Bulk's modulus) rock strength parameters (unconfined compressive strength, tensile strength, friction angle) and in-situ stress magnitude and direction (Kumar, P. et al. 2018).

In the present paper, a robust MEM model was prepared by using log data. Formation Micro Imaging data were analysed for Drilling Induced Tensile

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Fracture (DITF) and breakouts to estimate orientation of maximum and minimum horizontal stresses. LOT and MDT data have been taken from nearby well as no pressure measurements were carried out in reservoir section for calibration purposes. This MEM model can be used to provide the necessary inputs for safe drilling and planning of HF job.

Methodology of MEM Construction

This study includes, integrated interpretation of electrolog to understand the stress distribution in Chhatral pay of Cambay Shale in Gamij field. A wide variety of data has been used to build MEM, which include conventional log data, Image data, drilling data (mud weight, FIT /LOT) and Formation Pressure Measurement (MDT/DST) (Afsari et al. 2010).

Density Profile:

To calculate Overburden Gradient (OBG), density log is required from top to bottom of the well. However, density log was available in 8 1/2" section only. Using extrapolation method, density trend was constructed up to the surface by using Miller's method.

Overburden/Vertical Stress (S_v):

The magnitude of vertical stress calculated by integrating formation bulk density through the overburden depth (i.e along true vertical depth).

Normal Compaction trend:

Development of normal compaction trend is most crucial, as it requires the selection of shale points only. Based on shale intervals selected on the lithology curve, corresponding values indicating porosity (i.e. Resistivity and/or DT) dataset. After selection of shale points, the NCT is developed by drawing the line on the track based on sonic data.

Pore Pressure:

The pore pressure was predicted by normal trend method i.e by Eaton's sonic method. The estimated pore pressure curve is calibrated from MDT pressure measurement of nearby well. This predicted pore pressure curve is in agreement with the MDT pressure measurement.

Fracture Pressure:

Fracture pressure is calculated using pore pressure, overburden pressure and Poisson's ratio as inputs in Poisson's ratio model proposed by Anderson.

The calibrated pore-pressure and fracture pressure profile is presented in figure-2 and figure-3 of well A and well B respectively.

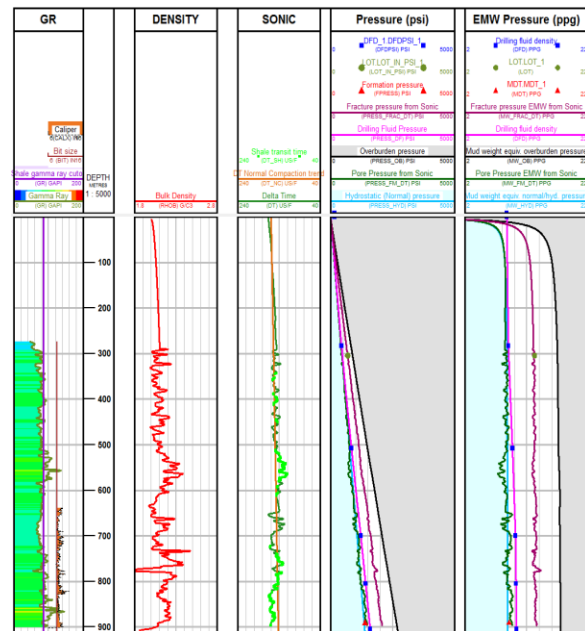


Figure-2: Calibrated pore-pressure and fracture pressure profile in well Well-A.

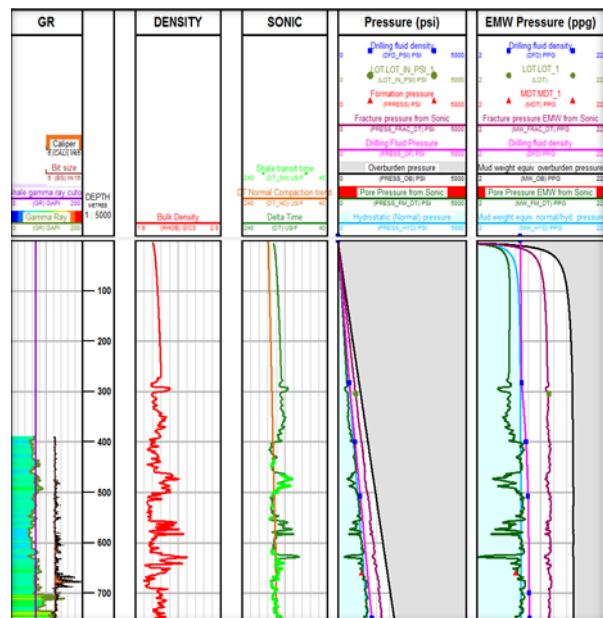


Figure-3: Calibrated pore-pressure and fracture pressure profile in well Well-B.

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Estimation of Principal Horizontal Stress (Shmin / SHmax)

Orientation of the principle horizontal stresses with respect to the borehole is an important factor affecting the wellbore stability. Breakouts occur when the stress concentration exceeds the rock strength of the wellbore in the direction of minimum horizontal stress. DITF occur in the direction of maximum principle horizontal stress. FMI log data is typically used to determine the orientation of principle horizontal stresses. Direction of SHmax can also be inferred from fast shear azimuth data of Sonic Scanner. Another generalized method to determine the azimuth of horizontal stresses is by world stress map. In this study, Image log based stress orientations are validated by World Stress Map (WSM).

The Drilling Induced Tensile Fractures (DITF) in well Well-A and Well-B on FMI logs have been analysed for estimation of SHmax direction. The DITF indicates, the SHmax direction to be in the range 110⁰-130⁰ North (EES-WWN direction) in well Well-A. The Shmin direction is around 20⁰- 40⁰ North. Similarly the direction of SHmax in well Well-B is in the range 130⁰- 140⁰ North (SE-NW direction). The Shmin direction is around 40⁰- 50⁰ North. Well trajectory profiles also generated at different depth for both the wells. Estimation of direction of SHmax using FMI, Steronet stability plot and WSM in well Well-A and Well-B is shown in figure 4 and figure 5 respectively. The final estimated SHmax is in the range 110⁰-140⁰ North. The orientation of Shmin in both the wells are validated with regional stress direction in WSM. It is evident that the stress regime in the entire interval is normal fault regime ($S_v > SH_{max} > Sh_{min}$).

Direction of Horizontal stresses:

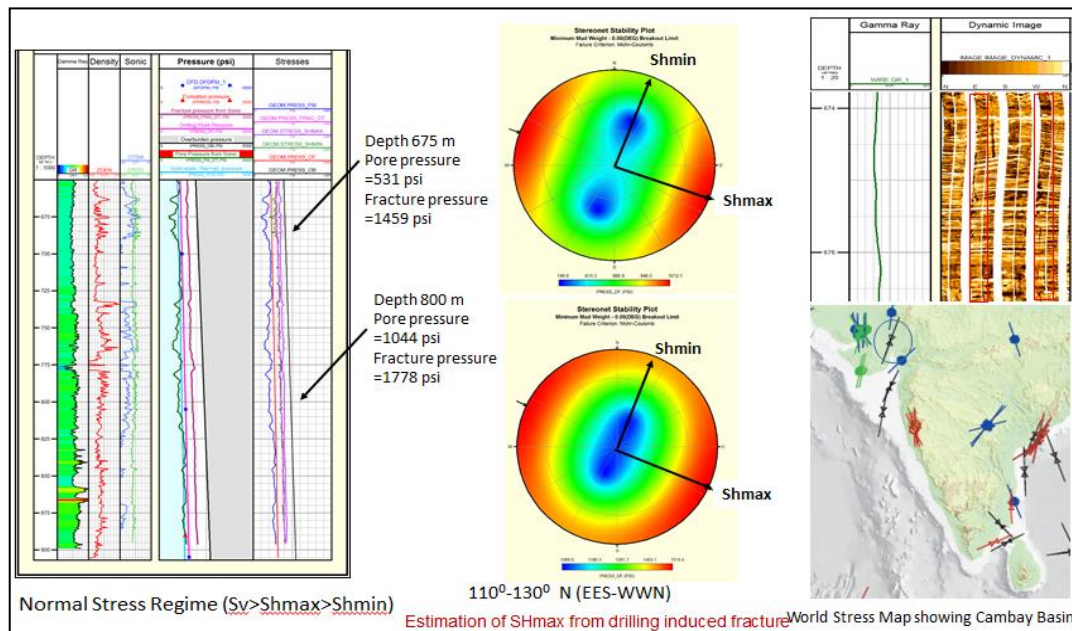


Figure 4: Estimation of direction of SHmax in well Gamij-A using FMI, Steronet stability plot and WSM.

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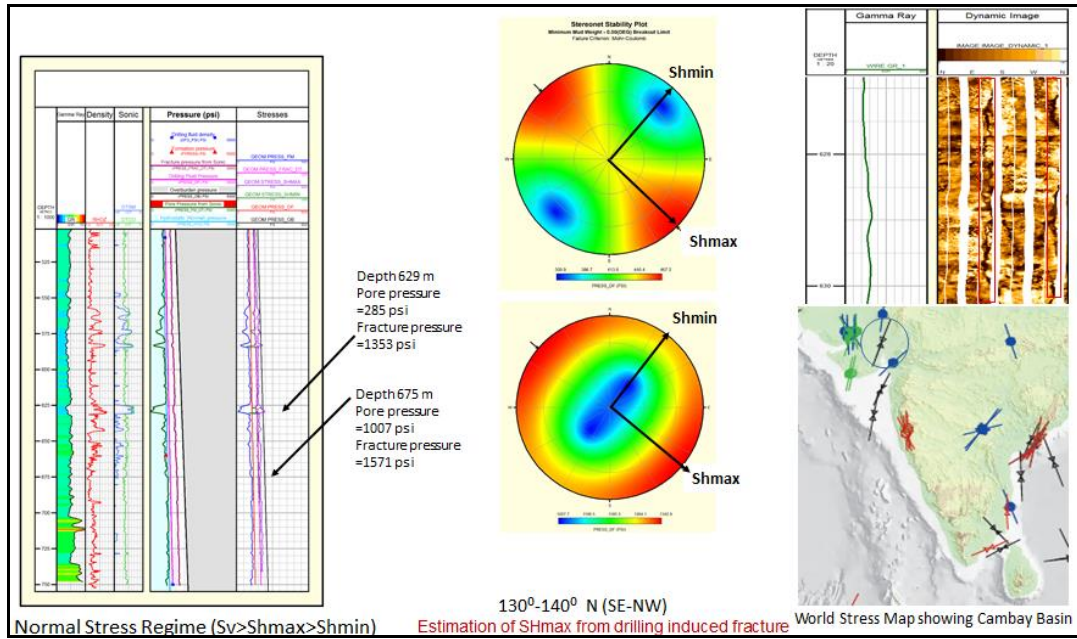


Figure 5: Estimation of direction of SHmax in well Well-B using FMI, Steronet stability plot and WSM.

Minimum Horizontal Stress (Shmin):

The magnitude of Shmin is important to determine the stress regime. The most accurate value of minimum horizontal stress is obtained from Extended Leak off Tests (XLOT) or Mini-frac test determining the fracture closure. The magnitude of Shmin and SHmax have been computed using Poro-elastic horizontal strain model (equation 1 & 2)

$$\sigma_{Hmax} = \frac{\nu(P_{OB} - \alpha \cdot P_{FM})}{(1-\nu)} + \alpha \cdot P_{FM} + \frac{Y \cdot \epsilon_{Max}}{(1-\nu^2)} + \frac{\nu \cdot Y \cdot \epsilon_{Min}}{(1-\nu^2)} \quad (1)$$

$$\sigma_{Hmin} = \frac{\nu(P_{OB} - \alpha \cdot P_{FM})}{(1-\nu)} + \alpha \cdot P_{FM} + \frac{Y \cdot \epsilon_{Min}}{(1-\nu^2)} + \frac{\nu \cdot Y \cdot \epsilon_{Max}}{(1-\nu^2)} \quad (2)$$

Where

- σ = Stress
- ν = Poisson's ratio
- ϵ = Strain
- Y = Young's modulus
- α = Biot Coefficient
- P_{OB} = Overburden Pressure
- P_{FM} = Formation Pressure

ϵ_{Min} and ϵ_{Max} are empirical constants which define the tectonic strain in the minimum and maximum horizontal stress directions. Values of Young's modulus, static Poisson's ratio, pore pressure and overburden stresses were estimated based on the constructed Mechanical Earth Model. The value of strain min and strain max will be changed until a good match of Shmin (σ_{Hmin}) profile with fracture pressure curve is achieved. This fracture pressure curve is taken as minimum stress magnitude as it is being validated by LOT/PIT data. The final calibrated profile of Shmin is shown in figure-6 and figure-7 of well A and well B respectively.

Maximum Horizontal Stress (SHmax):

The magnitude of SHmax cannot be determined directly. This can be estimated from image log data. Therefore, borehole failure such as breakout and DITF observed on image logs, can be used to calibrate the SHmax. It also requires knowledge of pore pressure, calibrated rock strength, vertical stress and minimum horizontal stress data.

Wellbore Stability Prediction

Safe mud window is defined as the mud pressure between the pore pressure and Shmin. When the mud pressure is less than the formation pressure, the fluid

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enters the kick zone and begins to flow. On the other hand, if the mud pressure exceeds the S_{hmin} , the drilling induced fracture start to initiate causing the well to go through partial mud loss (Afsari et al. 2010). The drilling Induced tensile fracture were observed in well Gamij-A and Gamij-B. The presence of DITF also observed in mud weight window tack, which is very well validated from image log data of the respective wells.

The static rock properties in entire interval also calculated based on different empirical relations to convert dynamic elastic properties to static elastic properties. The lab derived elastic parameter from the core shows good correlation with dynamic elastic properties from DSI measurement against studied core interval in near by well of the study area. The rock strength parameters; Unconfined Compressive Strength, Friction angle and tensile strength are important in conducting well bore stability analysis. Wellbore stability analysis was carried out by taking all these inputs and is presented in figure 6 and figure 7 for well A and well B respectively.

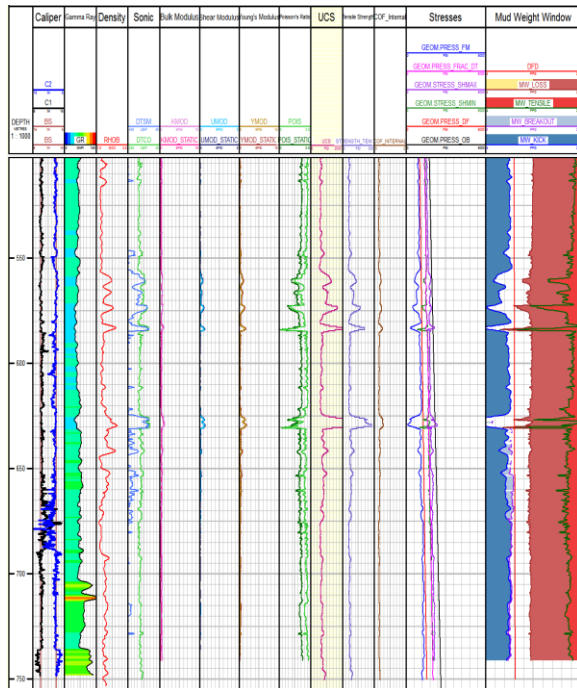


Figure 6: Elastic properties, PR, V_p/V_s (static/dynamic), UCS, strength tensile, internal friction angle along with predicted safe mud window (white) in well Well-A. Drilling Induced Fracture was observed at depth 675 m.

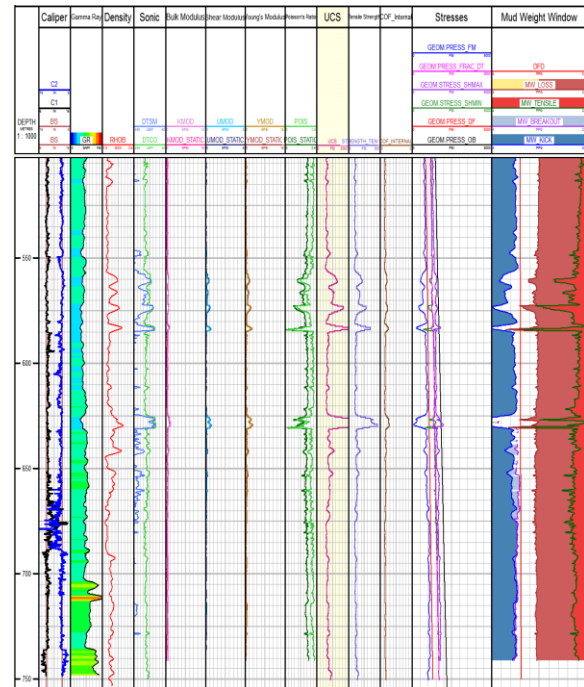


Figure 7: Elastic properties, Poisson ratio, V_p/V_s (static/dynamic), UCS, strength tensile, internal friction angle along with predicted safe mud window (white) in well Well-B. Drilling Induced fractures were observed at depth 590 m and 629 m.

Conclusions

- Estimated pore pressure and fracture pressure for 1D-MEM show good match with MDT and LOT of nearby wells.
- Pore Pressure, Fracture Pressure, Overburden pressure and Min & Max Stress magnitudes are generated for studied wells.
- Direction of principal horizontal stress (S_{Hmax}) estimated is in the range $110 - 130^\circ$ North (EES-WWN) in well Gamij-A and $130 - 140^\circ$ North (SE-NW) in well Gamij-B.
- Estimated maximum horizontal stress direction is $N 125^\circ \pm 15^\circ$; the average pore pressure gradient is 0.359 ± 0.02 psi/feet and the average fracture pressure gradient is 0.687 ± 0.08 psi/feet.
- Three principal compressive stresses ($S_v > S_{Hmax} > S_{hmin}$) indicates normal fault regime exists in studied wells.
- Stereo-plots of well trajectory profiles indicate the failure zones which can be avoided to plan for better



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- well stability and planning of HF job.
- Safe mud weight window is generated for parametric wells.

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