

Geomechanical study of low porosity and ultra-low mobility oil reservoirs for Multistage Hydro Fracturing - A case study from KG Basin, India

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Abstract

Hydraulic fracturing technology is widely used to facilitate and enhance the oil & gas recovery process from low permeability tight reservoirs which cannot be produced economically without hydraulic fracturing. The role of Geomechanics in design and evaluation of hydraulic fracture stimulations in unconventional reservoirs has become more important than ever. By understanding reservoir rock mechanics and those parameters that have a major impact on the performance of fracture treatments, more reliable decisions in fracturing design and optimization can be made.

The wells drilled in the south-west graben of the West Godavari sub-basin on the onland part of the Krishna-Godavari (KG) Basin has a objective to explore and appraise economical potential of tight oil reservoirs from Late Jurassic to early Cretaceous petroleum system. Some of the major inherent challenges of this Basin is to complete and test the wells within very tight deep sands in HPHT conditions.

The target reservoir consists of two distinct pay zones, the lower part is G-Formation which consists of stacked micaceous and mainly gritty sandstones and the upper part is R-Formation consists shale/sand sequences. These reservoirs are having low porosity (6-9%) & ultra-low mobility (0.03-0.08mD/cP). Both G and R reservoirs are high pressure (~9000 psi) & high temperature (300-325 degF) and tight in nature. Commercial flow of oil could not be established on self from conventional testing of offset wells, therefore multistage hydraulic fracturing was proposed and executed to facilitate production at economic rates.

This paper covers the Geomechanical study by using advanced acoustic measurements in three wells namely A1, A2 & A3. This study enabled to construct MEM (Mechanical Earth Modelling) to identify closure pressure, breakdown pressure and potential stress barriers in target reservoirs. Principal stresses (vertical, minimum and maximum horizontal stresses), pore pressure & fracture gradients helpful in identifying major stress barriers which can be act as barriers for vertical extent of fracture growth. Multiple perforation zones were identified based on the stress barriers to cover the entire hydrocarbon pay thickness keeping in view of oil water contacts. Multi stage HF was designed based on the MEM of Advanced acoustic measurements and executed in the wells A1, A2 & A3. Geomechanical study helped in success of multistage hydrofracturing and flowed oil with economic rates.

Introduction and Geology of the area:

India was the Fifth largest energy consumer in the world in 2018. Currently India is importing around 84% of oil to meet its energy requirement, which makes it pertinent to explore new basins as well as enhance production from existing basins. There are many HPHT reservoirs in India that currently lie untapped. Krishna Godavari basin is a proven petroliferous deltaic basin formed by discharge of two large rivers Krishna and Godavari flowing on east coast of India. Maximum deposition thickness found in this basin is up to 6KM with paleontological evidence suggesting period of slow deposition and subsidence.

The KG basin holds the one of the largest hydrocarbons deposit of India discovered in the last decade. A number of fields in KG basin consists rock of very poor formation permeability that requires hydraulic Fracturing to be able to produce from these Formations.

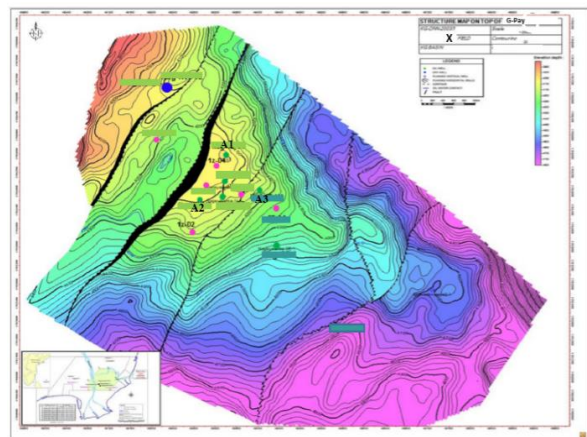


Fig-1: Map showing the studied area of Field "X" of KG Basin

The field 'X' (Fig-1) is located in a south-west graben of the West Godavari sub-basin on the onland part of the Krishna-Godavari (KG) Basin. This block is characterized by the presence of a prospective late syn-rift Cretaceous sequence that formed in response to rifting of India from Antarctica during the breakup of

Gondwana (Majumdar et al. 1995; Biswas, 2003). In the Cretaceous, the basin became a pericratonic rift in which thick deposits of marine to fluvial sediments accumulated within the grabenal areas associated with basement block faulting due to the reactivation of NE-SW trending Precambrian faults. The Cretaceous sequence begins with the sand dominated G- formation in the West Godavari sub-basin. Structurally, this area contains a number of rotated fault blocks separated by half grabens which are arranged in an en-echelon manner and offset by major cross-faults.

This paper discuss the field ‘X’ (Fig-1) that consists of two major sandstone layers in two Formations known as ‘R’ of Upper Cretaceous age and ‘G’ of Lower Cretaceous to Jurassic age . The G-Formation comprises a series of stacked micaceous and gritty sandstones containing abundant plant fossils that date it as Neocomian, interpreted to represent fluvial deposits draining into marine embayments defined by the graben and horst structures. The overlying R-Formation represents the first significant marine transgression and contains a rich fauna of ammonites, brachiopods and foraminifera that indicate a Barremian to early Aptian age (Prasad and Pundir, 1999). This shale thins westwards and onto the structural highs in the basin, where significant sandstones, including the R-Formation Sandstone and T-Formation Sandstone, that are derived from the west and northwest, and area considered as Upper Cretaceous in age (Kapoor et al., 1999).

Reservoir Description:

Wells- A1 & A2 are in one block and well-A3 is in another block of the same field ‘X’. In Wells- A1& A2, pay sands were developed in G and R-Formations where as in well-A1, pay sands developed in G-Formation only. The following table summarizes the reservoir properties for both G & R- Formations of the wells-A1, A2 & A3 which were considered for this study;

Table:1 Reservoir Description

Parameters	Data Source	Units	Gollapalli	Raghavapuram
Reservoir Fluid	Offset well	-	Oil	Oil
Gross Thickness	OH logs	m	360-395	5-42
Net PayThickness	OH logs	m	80-250	3-24
Estimated reservoir pressure	Offset well	Psi	~9000	~8500
Average porosity	OH logs	%	7-9	12-15
Average water saturation	OH logs	%	40-50	18-30
Range of Permeability	Core analysis of Offset well	mD/cP	0.01-0.17	-
Static young’s Modulus	OH logs	Mpsi	3.5-4	1.5-3.2
Bottom Hole temperature	OH logs & Gradient Calculation	degF	315-320	295-305

Based on petrophysical analysis, gross thickness of G-Formation is in the range of 360-395m where net pay thickness is estimated in the range of 80-250m. In general, G-Formations are significantly thicker than R formations. So, overall producibility of G-Formation is expected to be higher.

Challenges;

G and R Formations are lying at the high temperatures of 300-325degF and static bottom hole pressures of 12000-13500psi. These reservoirs are having low porosity (6-9%) & ultra-low mobility (0.03-0.08mD/cP). Static young’s Modulus varies from 2.5 to 7 Mpsi, anticipated fracture gradient of ≥ 0.9 psi/ft and In-situ stresses of ≥ 13000 psi which needs to be properly designed for hydrofracturing. So, testing & completion of this type of reservoirs made extremely challenging. To overcome these challenges, rigorous workflow was prepared incorporating expertise from different segments such as petro-physicist for detailed log evaluation, geo-mechanist for rock-mechanical earth modelling, geologist for reservoir characterization, completion engineer for optimising completion design and efficient well completion and stimulation engineers for stage selection and fracturing design, execution and evaluation.

Mechanical Earth Modelling with Advanced Acoustics for Geomechanical analysis;

The use of a Mechanical Earth Model (MEM) allows all information related to the Geomechanics of drilling and production to be captured, including in-situ stresses, rock-failure mechanisms, rock mechanical parameters, geologic structure, stratigraphy and well geometry. To improve the chance of successful stimulation, a technical workflow was developed for designing and executing jobs in this complex environment for three wells in this field. Our approach with robust Geomechanical analysis helped to build a better MEM with constrained stresses and a better understanding towards rock mechanical properties, enabling improved multi stage hydraulic fracture design in the targeted wells.

Advanced acoustic measurements have been recorded in A1, A2 & A3 wells providing near-wellbore and far-field stress profiles to calibrate the local stress regimes and rock mechanical properties. One dimensional mechanical earth models (1D MEMs) have been constructed for these wells to develop a Geomechanical understanding of the reservoir as well as in the overburden and under burden layers.

The conventional Geomechanics workflow for hydraulic fracturing applications relies heavily on multiple external inputs for reliable mechanical earth modeling (MEM). The uncertainty in stress calibration increases in basins that are not tectonically relaxed. In such situations, it is many times too late to redesign the perforation clusters and plan remedial actions after calibration injection tests, which can lead to suboptimal main hydraulic fracturing stimulation.

Keeping the uncertainties of conventional geomechanical workflows, an alternate method of MEM calibration was adopted (Fig-2). The alternate workflow was needed because of the paucity of core data, the geological complexity, and surprises that had been experienced during previous stimulation campaigns in this field. 3D shear velocity radial profiling data from advanced acoustic logs were used to invert the minimum and maximum horizontal stresses (Sinha et al. 2006, 2009). Using the inverted stress regimes and 3D shear velocity profiles, the MEM rock mechanical properties were constrained (Sayers et al. 2007). The workflow offered advantages for optimizing the perforation clusters and planning the most effective stimulation treatment schedule.

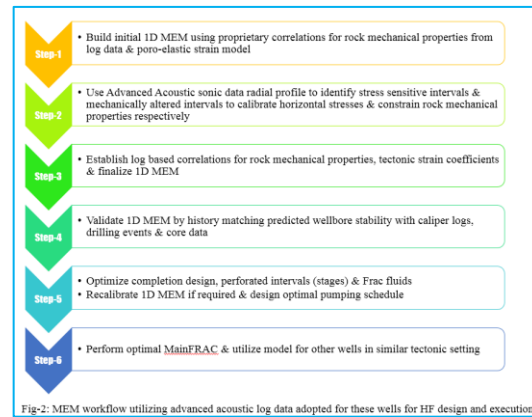


Fig-2: MEM workflow utilizing advanced acoustic log data adopted for these wells for HF design and execution.

Stress Analysis:

In Geomechanics, fracture gradient refers to the pressure needed to propagate the fracture away from the wellbore and cause lost circulation. This is close to the minimum principal stresses identified as fracture closure pressure from the pressure drawdown curve after mini-frac or extended leak-off test (pressure drop during shut-in phase). The breakdown gradient is a function of the principal stresses and tensile strength of the rock and varies with azimuth and deviation. Because no direct measurement of maximum horizontal stress are possible it is necessary to estimate the horizontal stress magnitudes from modelling of wellbore failure (breakouts and/or drilling induced fractures) of the two horizontal stresses, the minimum horizontal stress is usually more straightforward to determine and calibrate with LOT/FIT’s measurements etc, where the maximum horizontal stress can be more difficult to determine.

In this study a poro-elastic horizontal strain model (Fjaer et al 1992) was used to estimate the magnitude of the minimum and maximum horizontal stresses. The technique doesn’t pre determine or preconceive the order of the in-situ stresses but instead allows the convergence towards estimates of stress magnitudes that are driven by the available log and well data.

$$\sigma_h = \frac{\nu}{1-\nu} \sigma_v - \frac{\nu}{1-\nu} \alpha P_p + \alpha P_p + \frac{E}{1-\nu^2} E_x + \frac{\nu E}{1-\nu^2} E_y$$

$$\sigma_H = \frac{\nu}{1-\nu} \sigma_v - \frac{\nu}{1-\nu} \alpha P_p + \alpha P_p + \frac{E}{1-\nu^2} E_y + \frac{\nu E}{1-\nu^2} E_x$$

Where σ_h =minimum horizontal stress ; σ_H =maximum horizontal stress ; σ_v =overburden stress; E_x =strain at minimum horizontal stress direction; E_y =strain at maximum horizontal strain direction; α =Biot elastic coefficient; P_p =pore pressure respectively.

The stress regime of all the three wells calibrated by advanced shear radial profiling analysis shows a strong strike-slip regime with significant stress anisotropy in the G-Formation sands (seen as an increase in the horizontal maximum and minimum stress contrast of approximately 6,000 psi) as compared to the R-Formation sands (contrast of approximately 2000 psi). With increase in overburden stress, a decreasing side burden stress trend is seen in the G-Formation, leading to a reduction of fracture and breakdown gradients. There are very few stress barriers inside the G-Formation. These barriers are due to the higher Young's modulus of the layers and are not necessarily dependent on the shaliness.

The final stress profile of wells A1, A2 & A3, obtained after history matching process and utilizing the advanced sonic tool data reveals strike-slip stress regimes (Fig.3)

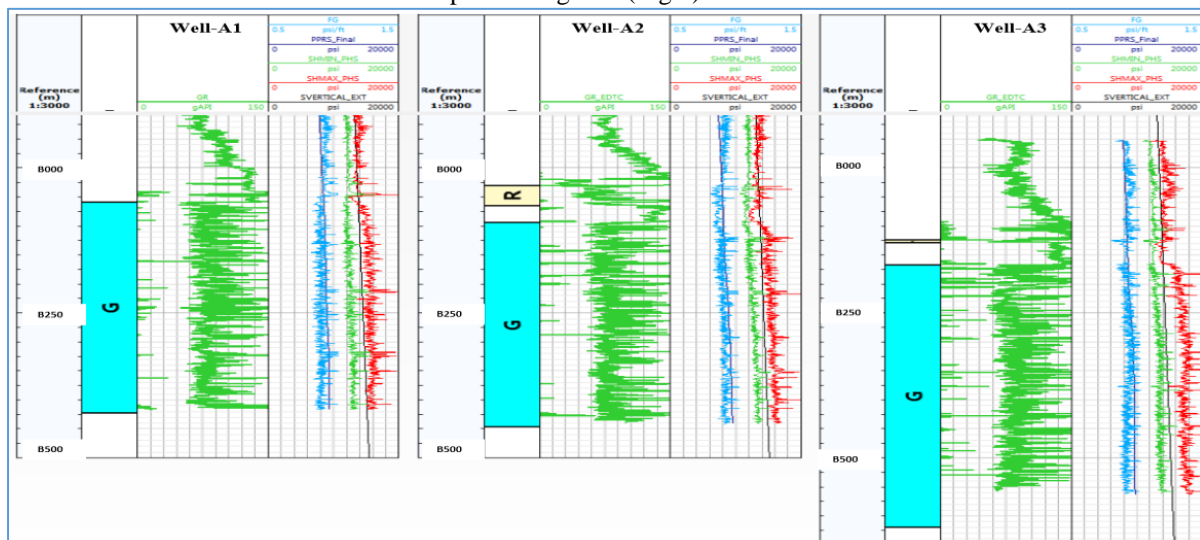


Fig-3: Pore pressure, Min & Max Horizontal Stresses, Vertical stress and Fracture Gradient of wells A1, A2 & A3 (Track-1: GR (Green); Track-2: Horizontal Max & Min stresses (SHMAX_PHS-red & SHMIN_PHS-Green), Vertical stress (Svertical_EXT-Black), Pore Pressure (PPRS_Final-Navy Blue) & Fracture Gradient (FG-Blue))

Based on the processed results of sonic scanner data, fast shear azimuth (FSA) is in the range of N10E deg-N45E deg, N10E deg-N75E deg & N10E deg-N65EE deg for the wells-A1, A2 & A3 respectively (Fig-4). As per fast shear azimuth (FSA), Maximum horizontal stress direction is NE-SW for wells-A1,A2 & A3.

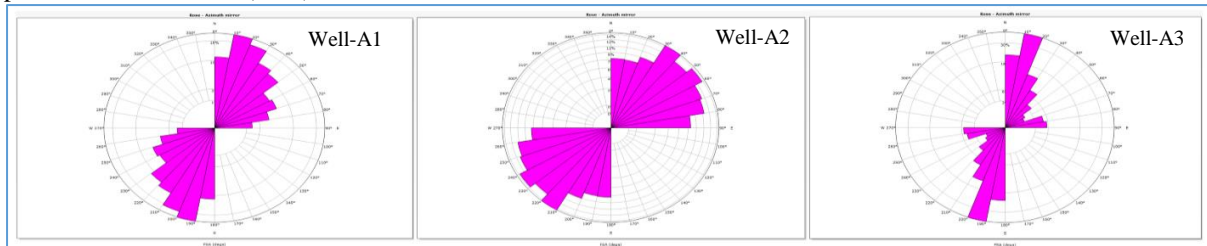


Fig-4:Fast Shear Azimuth from Sonic Scanner (SigH Direction) of the wells- A1,A2 &A3 respectively

Well-A1:

- ❖ Advanced Acoustic measurements were carried out in the well-A1 and detailed analysis was carried out for identifying the high stressed layers and major barriers inside G-Formation (Fig-5).
- ❖ A clear stress barrier was observed at transition of R-Formation to G-Formation in all the three wells.
- ❖ Estimated pore pressures are 8500-9300psi across Gollapalli formation.
- ❖ Ratio of maximum horizontal stress to minimum horizontal stress is 1.06-1.25 which depends on stiffness of layer.
- ❖ Estimated closure pressure ranges 11300psi-13900psi while breakdown pressure ranges 12400 to 14800psi in layers with good effective porosity in G-Formation.
- ❖ There are few intermediate depth intervals with higher horizontal stress profile and breakdown pressures: B050-B059m, B132-B137m, B207-B214.5m, B223-B230m, B319-B325m, and B341-B351m which may act as stress barriers to limit the vertical growth of the fracture when hydro-fractured as shown in Fig-5.
- ❖ Major stress barriers with contrast of 1200-1500psi was observed within G-pay.
- ❖ 4 Perforation zones for multi stage HF planned between major stress barriers; Zone-1:B238.5-B241.5m, Zone-2:B184-B187m, Zone-3:B140-B143m & Zone-4:B096-B099m.
- ❖ After multi-stage HF well flowed clean oil.

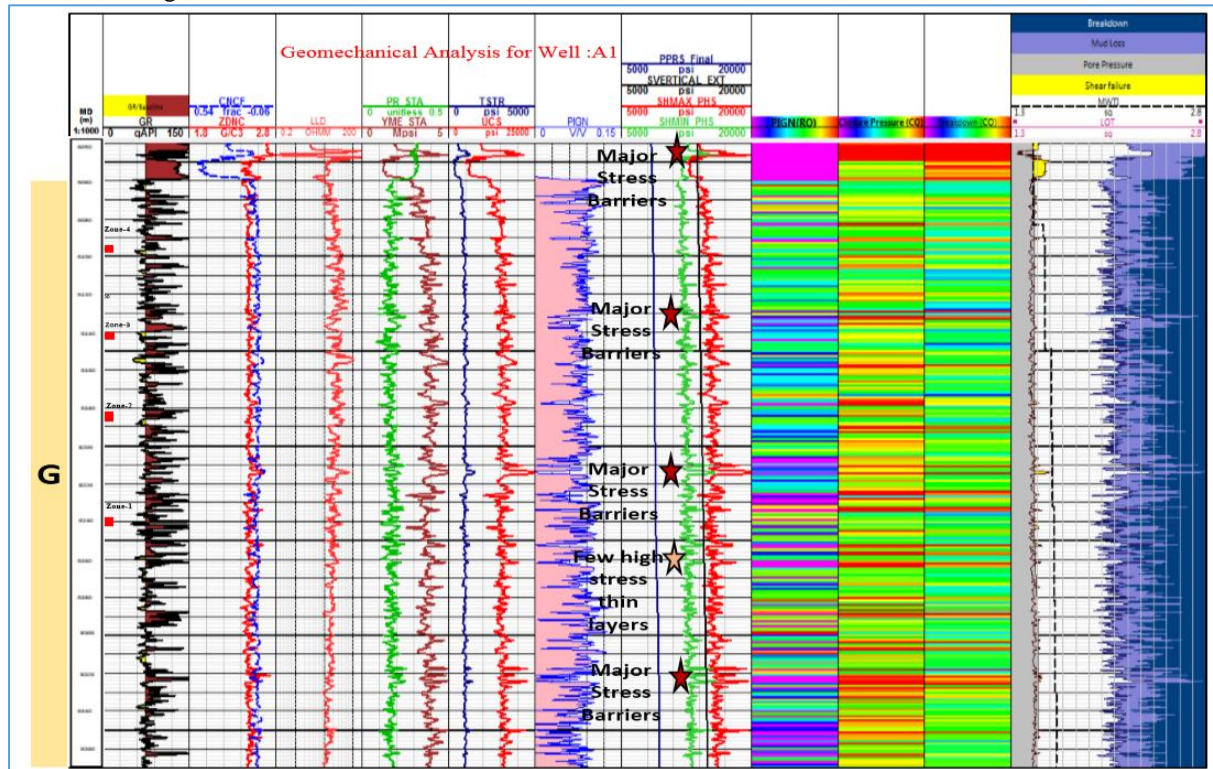


Fig-5: Identification of zones based on stress profiles in well-A1

(Track-1: GR; Track-2: Neutron-Density; Track-3: Resistivity; Track-4: PR & YME; Track-5: Tensile Strength & UCS; Track-6: Effective Porosity; Track-7: Pore pressure, Minimum horizontal stress, maximum horizontal stress & vertical stress; Track-8: porosity shaded; Track-9: Closure pressure gradient-shaded with red as higher values; Track-10: Breakdown Pressure-Shaded with Red as higher values; Track-11: Shear failure Limit, Kick Pressure EMW, Mud loss=Fracture Gradient EMW, Breakdown EMW)

Well-A2:

- ❖ Advanced Acoustic measurements were carried out in the well-A2 and detailed analysis was carried out for identifying the high stressed layers and major barriers inside R & G-Formations (Fig-6).
- ❖ There is clear stress barrier at transition from R-Formation to G-Formation
- ❖ Estimated pore pressures are 8300-9500psi across G-Formation.
- ❖ Ratio of maximum horizontal stress to minimum horizontal stress is 1.05-1.33 which depends on stiffness of layer and tectonics component.

- ❖ Estimated closure pressure ranges 11000psi-13200psi while breakdown pressure ranges 12300psi-14800psi in layers with good effective porosity in G-Formation.
- ❖ There are few intermediate depth intervals with higher horizontal stress profile and breakdown pressure: B119.7m-B127m, B142.9m-B146m, B212m-B217.9m, B231.9m-B239.1m, B283.6m-B293.7m, B321 m-B326.7m, B346.4m-B362m, B365.5m-B373m, B399m-B408m and B417m-B423m with stress contrast 1200-1500 psi in G-Formation as shown in Fig-6.
- ❖ The estimated closure pressure ranges from 10500psi -11000psi and breakdown pressure ranges from 11800- 12000psi in layers with good effective porosity in R-Formation. Major stress barriers are observed within this formation in the intervals B019.8-B029.6m, B035.7-B037.2m, B051.3-B053.1 with stress contrast of 900-1600psi.
- ❖ 4 Perforation zones for multi stage HF planned between major stress barriers; ZONE-1:B240-B243m, ZONE-2:B222-B224m, ZONE-3:B192-B195m & ZONE-4:B156-B159m
- ❖ One interval i.e B044-B047m was recommended in between major stress barriers for multi stage hydro-fracturing in R-Formation as shown in Fig-6.
- ❖ After multi-stage HF well flowed clean oil.

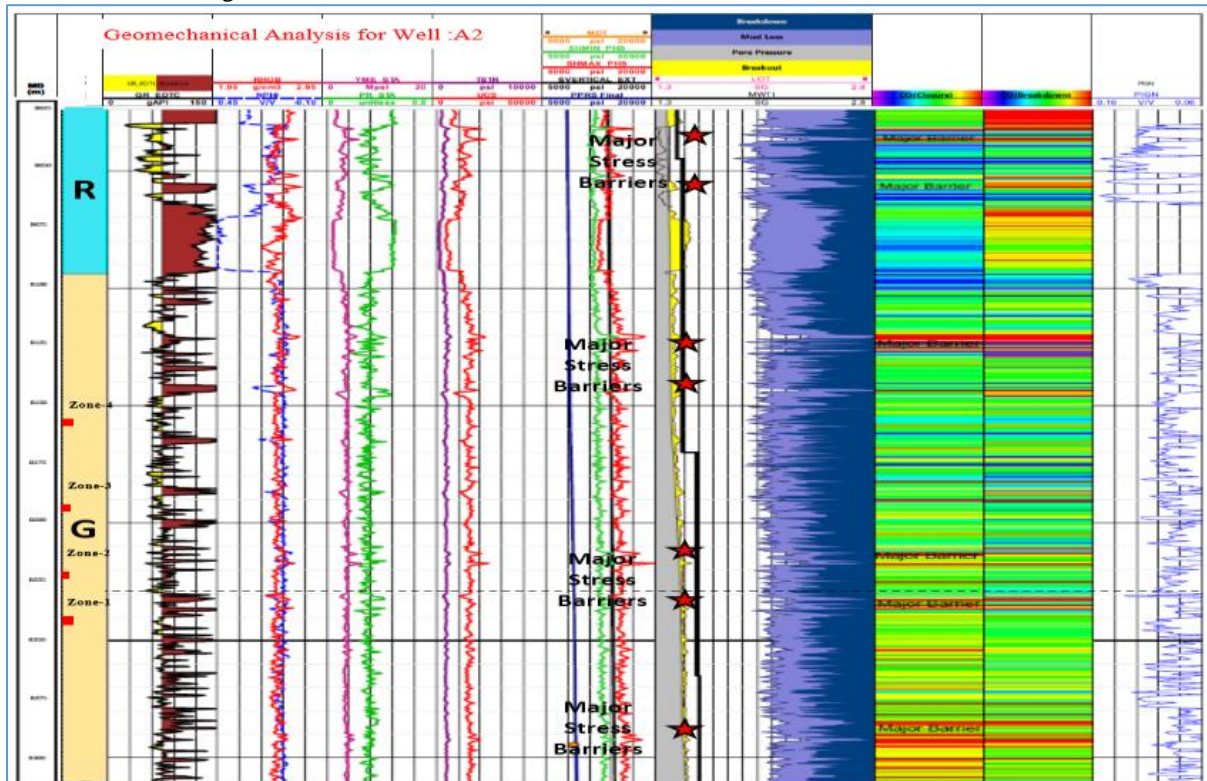


Fig-6: Identification of zones based on stress profiles in well-A2

(Track-1: GR; Track-2: Neutron-Density; Track-3: PR & YME; Track-4: Tensile Strength & UCS; Track-5: Pore pressure, Minimum horizontal stress, maximum horizontal stress & vertical stress ; Track-6: Shear failure Limit, Kick Pressure EMW, Mud loss=Fracture Gradient EMW, Breakdown EMW, Mud weight used and Leak-off pressure EMW (LOT) ; Track-7: Closure pressure gradient-shaded with red as higher values; Track-8: Breakdown Pressure-Shaded with Red as higher values; Track-9: Effective Porosity)

Well-A3:

- ❖ Advanced Acoustic measurements were carried out in the well-A3 and detailed analysis was carried out for identifying the high stressed layers and major barriers inside R & G-Formations (Fig-7).
- ❖ There is clear stress barrier at transition from R-Formation to G-Formation.
- ❖ Estimated pore pressures are 8750-9500psi across G-Formation.
- ❖ Ratio of maximum horizontal stress to minimum horizontal stress is 1.07-1.35 which depends on stiffness of layer. This contrast is higher than observed at recently drilled wells (A & B)
- ❖ Estimated closure pressure ranges 11000psi-13900psi while breakdown pressure ranges 12300psi-14900psi in layers with higher effective porosity in G-Formation.
- ❖ There are few intermediate depth intervals with higher horizontal stress profile and breakdown pressure: B182.6-B184m, B190-B192.6m, B202.2-B205m, B220-B224m, B293-B300m, B325-B330m, B366-B371m, and B445-B451m with contrast 600-1900psi in G-Formation as shown in Fig-7.
- ❖ Estimated closure pressure ranges 11000-11500psi while breakdown pressure ranges 12300psi-12600psi in layers with higher effective porosity in R-Formation.
- ❖ Major stress barrier observed within Raghavapuram formation is in the interval B120-B123m with contrast 1400-1800psi.
- ❖ Two Perforation zones for multi stage HF planned between major stress barriers; ZONE-1: B210-B211m & B187-B189.5m and Zone-2: B179-B181m.
- ❖ After multi-stage HF well flowed oil with water.

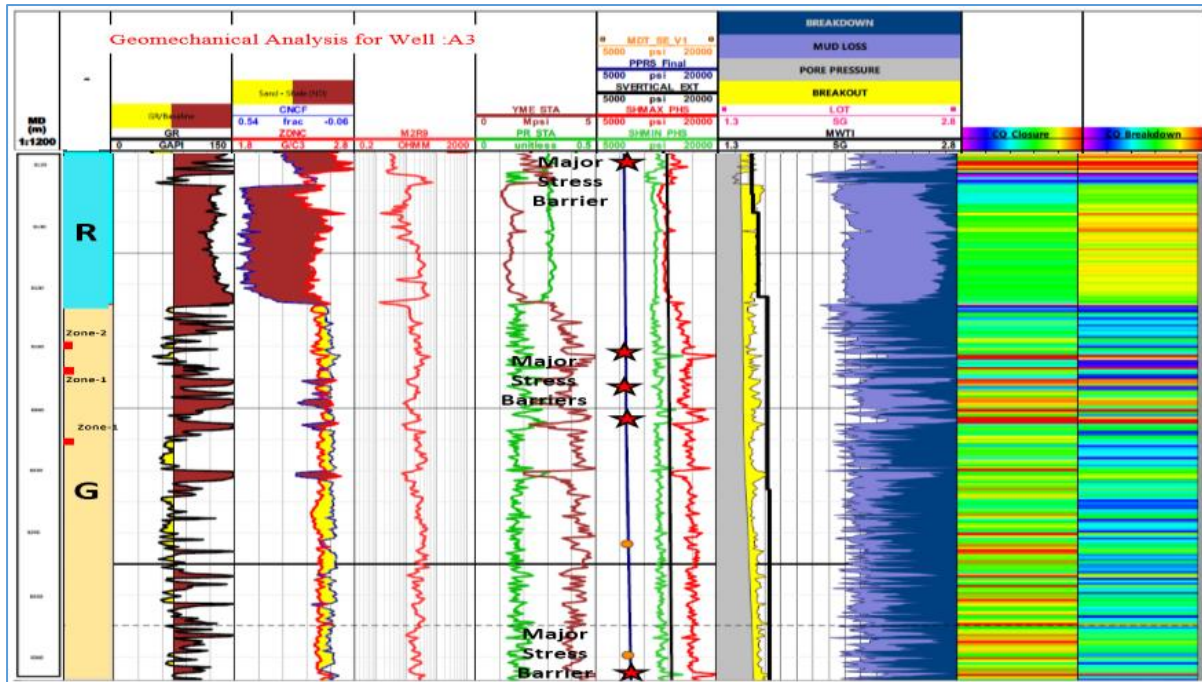


Fig-7: Identification of zones based on stress profiles in well-A3

(Track-1: GR; Track-2: Neutron-Density; Track-3: Resistivity; Track-4: PR & YME; Track-5: Pore pressure, Minimum horizontal stress, maximum horizontal stress & vertical stress; Track-6: Shear failure Limit, Kick Pressure EMW, Mud loss=Fracture Gradient EMW, Breakdown EMW, Mud weight used and Leak-off pressure EMW (LOT) ; Track-7: Closure pressure gradient-shaded with red as higher values; Track-8: Breakdown Pressure-Shaded with Red as higher values)

Multi stage HF was designed based on MEM of Advanced acoustic measurements & executed in all the three wells and flowed oil. Temperature logs during pre & post frac and Production logs confirmed all the frac stages were active and contributing hydrocarbons.

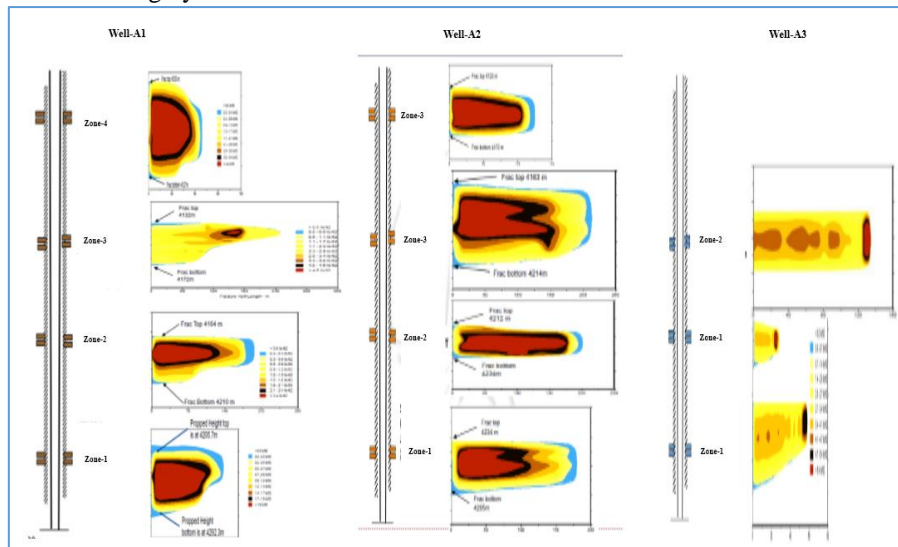


Fig-8: Pictorial view of Hydro-Fracturing in wells-A1, A2 & A3

Conclusions:

- Open hole logs of wells A1,A2 &A3 showed a potential thick oil column having low porosity and ultra-low mobility. These reservoirs need Hydraulic fracturing for production in economic rates.
- Advanced 3D acoustic measurements were carried out in all the three wells and generated the 1D Mechanical Earth Model including stress direction & magnitude, stress barriers & contrasts. These were used as inputs for multistage Hydraulic fracturing design.
- Major stress direction is in NE-SW in all the studied wells
- Stress contrast of 1200-1500psi in wells- A1 &A2 and 600-1900psi in well-A3 for G-Formation and 900-1600psi in well-A2 and 1400-1800psi in well-A3 for R-Formation. Major stress barriers identified from Geomechanical study used for perforation zone selection for multi stage HF.
- Frac gradients obtained from Geomechanical study are in the range of 0.91-0.93psi/ft in well-A3, 0.84-1.01psi/ft in well-A1, 0.94-1.02psi/ft in well-A2. These are in good matching with values obtained from the data frac.
- After Multistage HF, all the three wells flowed oil.



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