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Petrophysics: Solutions Through Integration
February 11 -12, 2017 Mumbai

Technical Proceedings - Vol 2
(Poster Presentations)
Dear Reader,

It gives me immense pleasure to present the Technical Proceedings of 4th SPWLA-India Symposium & Exhibition-2017 on the theme “Petrophysics: Solutions through Integration” held at NBP Green Heights, ONGC, Mumbai on February 11-12, 2017.

**Technical Proceedings Volume - II** consists of 33 Poster Presentations. The objective of publishing the proceedings is to provide a ready reference of the scientific deliberations that have taken place during the symposium. The proceedings highlight the integration of Petrophysics with other Geosciences for leveraging synergy and providing effective solutions.

Thanking you,

[Signature]

President,
SPWLA-India
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Introduction

Wellbore stability issues significantly increase drilling cost for oil and gas production into difficult geological and geographical conditions such as deepwaters and high-pressure and high-temperature (HPHT) reservoirs. Therefore, an accurate knowledge of in-situ stress condition for drilling stable wellbores becomes crucial in case for highly deviated or horizontal wells, underbalanced drilling and penetration into deeper unknown rock formations. This work presents in-situ stress state and pore pressure prediction in southern Cambay basin and a failure analysis of boreholes drilled in directions inclined to the far-field stress principal axes in a linear elastic, isotropic and homogeneous formation. We have used analytical stress solution of well known Kirsch equations. This solution takes into account two horizontal in-situ stresses, the axial stress, mud weight and pore-pressure. The failures in relation to borehole inclination, azimuth, and mud pressure have been presented for estimating wellbore fracture pressure and collapse pressure, thus a required mud weight window for optimizing a stable wellbore trajectory in southern Cambay basin.

Keywords In-situ stress; pore pressure; wellbore stability; mud weight; tectonics

Tectonic setting of Cambay Basin: The Cambay basin is a narrow, elongated, intra-cratonic rift graben bound on the eastern and western flanks by northwest to southeast and north-northwest to south-southeast trending basin-margin faults (Figure-1, 2a). The prospects are primarily fault bounded 3-way closures. Three major traps have been identified: 1. Syn-rift fan delta wedgeouts of the Olpad Formation; 2. Syn- to Late-rift pinchouts / wedgeouts of the Cambay Shale; 3. Early Post-rift subtle inversion combination traps of Ankleshwar / Dadhar / Tarkeshwar and Babaguru Formation (D.G.H. website).

Stratigraphy of study area: Generalized stratigraphy of Cambay basin exhibits presence of rocks from upper cretaceous to recent (Singh, 2012). Over the Deccan basalt, tertiary sediments have been deposited in synrift and post-rift phases (Figure-2b).

Petroleum systems: Cambay Shale is the major source rock. Fractured basement of Deccan trap being the reservoir rock makes the Cambay basin an unconventional oil field (Singh, 2012). Cambay shale acts as regional seal. There are various migration pathways from source to reservoir as shown in tectonic setting of Cambay basin (Figure-1).
Determination of in-situ stress

During drilling of an oil and gas well, formations exhibit pressure which varies in magnitude depending on depth of occurrence, geological setting, location and closeness to other structures (Rana and Chandrashekhar, 2015).

**Hydrostatic Pressure:** It is defined as pressure exerted by a column of fluid. It is a function of average fluid density, and depth or vertical height of fluid column. It can be calculated by the following formula:

\[ \sigma_h = \rho gh \]

Where \( \rho \) is the fluid density, \( g \) is the gravitational acceleration and \( h \) is height of the fluid column between a specific depth and a reference depth.
**Overburden pressure:** It is defined as the pressure exerted by the total weight of the overlying formations above the point of interest. Overburden stress is calculated from the bulk density log as below:

\[
\sigma_v = \int_0^d \rho_b(h)g dh
\]

Where \(\sigma_v\) is the vertical stress / overburden stress at depth TVD \(d\) and \(\rho_b\) is the bulk density (including the water section above sea floor); \(g\) is the gravitational constant.

**Horizontal stress:** Minimum horizontal stress \(s_h\) is calculated as follows:

\[
\sigma_h = \frac{\nu}{1-\nu} (\sigma_v - \beta P_0) + \beta P_0
\]

Where \(\sigma_v\) is the vertical stress / overburden stress at depth TVD, \(n\) is the Poisson's ratio and \(P_0\) is pore pressure and \(b\) is Biot's constant. For maximum horizontal stress \(s_h\), we have used horizontal stress ratio \((s_h/s_v)\) method in this study.

![Figure 3(a): Sonic log data used for pore pressure prediction (b) density data used for overburden stress calculation for a well in Broach block of Cambay basin.](image-url)
Pore pressure

For sandstone like reservoir, pore pressure is the pressure exerted by the fluids in the pore space (Rana and Chandrashekhar, 2015). But shale has extremely small pores, dominance of bound water and intense chemical effects. Hence for shale, pore pressure is the fluid pressure in permeable zone in long equilibrium with shale (Rana and Chandrashekhar, 2015). Pore pressure can be distinguished as normal or abnormal pore pressure.

A. Normal pore pressure: It is the pressure exerted by the column of the fluid extending from surface to the subsurface being considered. It varies with the concentration of dissolved solids, gases presents and type of fluids and temperature gradients (Rana and Chandrashekhar, 2015).

B. Abnormal pore pressure: Any pore pressure that is greater than hydrostatic pressure of the formation water occupying the pore space. It is also called as over-pressured or geo-pressure. Due to an extra amount of pressure over normal hydrostatic component, blow-out preventers (BOP) are required when drilling oil and gas wells. The cause of abnormal or over-pressured zone is due to various geological, geochemical, geothermal and mechanical changes. For development of abnormal pore pressure, an interruption in the normal compaction or de-watering is necessary (Rana and Chandrashekhar, 2015).

Pore pressure prediction

Predicting pore pressure is very important to determine the mud weight with which drilling is to be carried out. In case of underestimated pore pressure i.e. if mud weight is less than pore pressure, the problems like caving, flows from formation to wellbore, kicks and blow-outs, all threaten borehole stability and safety issues. In case of overestimated pore pressure, if it is near fracture pressure of a formation, formation will be damaged due to wellbore stability issues. High mud weight damages the reservoir formation so main objective of drilling a well is not found (Rana and Chandrashekhar, 2015).

Inaccurate analysis of pore pressure, fracture pressure and overburden pressure will cause drilling problems like stuck pipe and low rate of penetration (ROP) because of unnecessary high mud weight, improper casing design. These complications will result in high cost implications and non productive time (NPT). In this study, we have calculated pore pressure $P_0$ using acoustic log using Eaton's method. This method assumes there is a normal pore pressure with a fixed gradient.

$$P_0 = \sigma_v - (\sigma_v - P_h) \left( \frac{\Delta t_h}{\Delta t} \right)$$

Where, $P_h$ is the hydrostatic pore pressure (normally 0.45 psi/ft or 1.03 MPa /km), $\Delta t =$ measurement value at any depth and $\Delta t_s =$ sonic measurement for normal compaction trend line.

We have also estimated overburden stress from density log. $\sigma_s$ is computed using $\nu= 0.22$ and $\beta= 0.9$. $\sigma_s$ has been estimated using $\sigma_v/\sigma_s =1.2$. Two specific in-situ stress conditions i.e. normally pressured zone and over-pressured zone have been identified as shown in Figure-4 and Table 1.
**Figure 4:** The figure shows the variations of in-situ stress, pore pressure with respect to mud weight profiles and related parameters with depth in a well in southern Cambay basin. Pore pressure above hydrostatic gradient indicates overpressure zones. At depth B, very high overpressure develops. The absolute value of pore pressure is well above normal pressure compared to that at depth A. The green line shows the minimum horizontal stress (S_{hmin}) considered same as fracture gradient; blue line shows the pore pressure P_o; black line shows the overburden stress, S_v; the red line shows the hydrostatic pressure. Cyan color represents different MW profiles.

**Table 1:** Input parameters derived from in-situ stress and pore pressure prediction methods for wellbore stability analysis and mud weight optimization

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<th>Normally pressured zone</th>
<th>Overpressured zone</th>
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<tr>
<td>Depth d (in meter)</td>
<td>4140</td>
<td>4244</td>
</tr>
<tr>
<td>Pore pressure P_o (in MPa)</td>
<td>48</td>
<td>68.15</td>
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<tr>
<td>Mud weight P_w (in MPa)</td>
<td>53.65</td>
<td>54.91</td>
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<td>Overburden stress S_v (in MPa)</td>
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<td>95.97</td>
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<tr>
<td>Maximum horizontal stress S_{Hmax} (in MPa)</td>
<td>68.508</td>
<td>85.32</td>
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<td>Minimum horizontal stress S_{hmin} (in MPa)</td>
<td>57.09</td>
<td>71.10</td>
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**Near wellbore stress analysis**

Subsurface formations are always in a stressed state, primarily due to overburden and tectonic stresses. During drilling, the formation around the wellbore must sustain the load that was previously taken by the removed material (Aadnøy and Looyeh, 2011). The borehole wall is then supported only by the mud pressure in the hole. As this fluid pressure generally does not match the in situ formation stresses, there will be a stress redistribution around the well i.e. change in stress state around the wellbore and stress concentration will be produced (Aadnøy and Looyeh, 2011). If the strength of the formation is not enough to sustain the stress concentration, the wellbore is likely to fail. Hence, knowledge of the stresses around a well is essential for discussion of wellbore stability problems.
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**Figure 5:** (a) Stresses around a wellbore in the rock formation where $(\sigma_x, \sigma_y, \sigma_z)$ represents principal in-situ stress state, and, $(S_o, S_s, S_t)$ and $(S_o, S_s, S_t)$ represent stress states at the wellbore in Cartesian and cylindrical coordinate systems, respectively. (b) In-situ stresses acting in normal fault stress regimes (like in Cambay basin) (after Wikel, 2011).

Therefore, we have performed a failure analysis of boreholes drilled in directions inclined to the far-field stress principal axes in a linear elastic, isotropic and homogeneous formation (Figure-5a). We have used analytical stress solution of well known Kirsch equations (Annexure-1, 2). This solution takes into account two horizontal in-situ stresses, the overburden stress, mud weight and pore-pressure. We have studied the distribution of hoop stress, shear stress and radial stress concentration around a vertical ($\gamma=0^\circ$, $\varphi=0^\circ$), a horizontal ($\gamma=90^\circ$, $\varphi=20^\circ$) and a deviated ($\gamma=25^\circ$, $\varphi=20^\circ$) borehole (Figure-6 a, b, c; Figure-7) for normally pressured zone A (Figure-4). Orientation of $S_{Hmax}$ is N 90°E (east–west).

**Figure 6:** Variation of effective hoop stress ($\sigma_h$) in (a), radial stress ($\sigma_r$) in (b) and shear stress ($\tau_{th}$) in (c) are shown. Values of stress and pore pressure used for the calculations are described in the text.

**Figure 7:** Hoop stress variation in normally pressured zone. (a) for deviated well $\gamma=25^\circ$, and $\varphi=20^\circ$ and (b) for horizontal well $\gamma=90^\circ$, and $\varphi=20^\circ$. Stress and pore pressure parameters used for the calculations are same as in case of vertical well.

The stress concentration varies strongly as a function of position around the wellbore and distance from the wellbore wall. It is also symmetric with respect to the direction of the horizontal principal stresses.
Linearized Mohr failure criterion

Shear stress, $\tau$ and effective normal stress $\sigma$ on a plane that forms during the failure process can be evaluated in terms of the applied effective principal stresses $\sigma_i$ and $\sigma_j$,

$$\tau = \frac{1}{2}(\sigma_i - \sigma_j)\cos\phi$$  \hspace{1cm} (5)

$$\sigma = \frac{1}{2}(\sigma_i + \sigma_j) - \frac{1}{2}(\sigma_i - \sigma_j)\sin\phi$$  \hspace{1cm} (6)

Where $\phi$ is the angle of internal friction. The linearized Mohr failure line can be written in terms of cohesive strength $S_0$ and coefficient of internal friction $\mu$, to obtain uniaxial compressive strength as (Aadnøy and Looyeh, 2011):

$$\tau = S_0 + \sigma_i \mu$$  \hspace{1cm} (7)

$$C_0 = 2S_0 \left( \mu_i^2 + 1 \right)^{\frac{1}{2}} + \mu_i$$  \hspace{1cm} (8)

Figure 8: Zone of compressive failure around the wellbore wall for the assumed rock strength is indicated by the contour line. Uniaxial compressive strength ($C_0$) is coloured. (a) In normally pressured zone, no failure will occur for assumed Mohr-Coulomb failure criterion i.e. angle of internal friction $= 30^\circ$ and cut-off unconfined compressive strength (UCS) $C_z = 45$ MPa. Therefore, no breakouts would be seen. (b) In over-pressured zone, the expected zone of initial breakout formation with a width given by $W_{BO}$. Between the contour line and the wellbore wall, failure of even stronger rocks would have been expected (the scale indicates the magnitude of rock strength required to inhibit failure). Lower rock strength would result in a

Three principal stresses at the wellbore wall at the point of maximum and minimum stress concentration have been used to depict rock failure in three-dimensional Mohr diagram (Figure-9).
Figure 9: The three principal stresses at the wellbore wall at the point of maximum stress concentration (θ = 90°, 270°) shown as a three-dimensional Mohr diagram for (a) normally pressured zone, (b) abnormally pressured zone. If the strength of the rock is exceeded (a Mohr–Coulomb failure criterion is assumed, $C_o = 45$ MPa, $\mu = 1.0$), the rock on the wellbore wall is expected to fail.

**Effect of mud weight and pore pressure**

For the case of pore pressure equal to mud weight, wellbore breakout is shown in Figure-10c. For over-pressured zone B, effective $\sigma_z$ increases (and $\sigma_\theta$ decreases) at all positions around the wellbore (Eq. 18 and 19) as in Figure-10b. For normally pressured zone A, the zone of compressive failure is much smaller in terms of both $w_{ec}$ and breakout depth as in Figure-10a. Thus, increasing mud weight can be used to stabilize wellbores in this case.

**Mud weight optimization**

For wellbore fracture pressure, the resulting principal stresses at the borehole wall are (Aadnøy and Looyeh, 2011):

$$\sigma_1 = \sigma_r = P_w$$

$$\sigma_2 = \frac{1}{2}(\sigma_0 + \sigma_z) + \frac{1}{2}(\sqrt{(\sigma_0 - \sigma_z)^2 + 4(\tau_{0z})^2})$$

$$\sigma_3 = \frac{1}{2}(\sigma_0 + \sigma_z) - \frac{1}{2}(\sqrt{(\sigma_0 - \sigma_z)^2 + 4(\tau_{0z})^2})$$

The borehole will fracture when minimum effective principal stress reaches tensile rock strength i.e.

$$\sigma_3' = \sigma_3 - P_w \leq \sigma_i$$

For wellbore collapse, the stress conditions are as follows:

$$\sigma_1 = \frac{1}{2}(\sigma_0 + \sigma_z) + \frac{1}{2}(\sqrt{(\sigma_0 - \sigma_z)^2 + 4(\tau_{0z})^2})$$

$$\sigma_2 = \frac{1}{2}(\sigma_0 + \sigma_z) - \frac{1}{2}(\sqrt{(\sigma_0 - \sigma_z)^2 + 4(\tau_{0z})^2})$$

$$\sigma_3 = \sigma_r = P_w$$
Minimum required mud weight for initiation of borehole failures and tensile fractures (Figure-11) have been calculated by solving above equations respectively for both pressured zone A and B (Figure-4) (Zoback et al., 2003). Tensile strength was assumed as zero. Orientation of $S_h$ is N 90°W.

For a safe mud weight window, the lower hemisphere projection has been used to display the mud pressure required to initiate tensile failure (i.e. critical borehole pressure at fracture) and collapse failure for relative stability of wells with arbitrary orientation where each point represents a well of a given azimuth and deviation. Vertical wells correspond to a point in the centre, horizontal wells correspond to a point on the periphery at the appropriate azimuth and deviated wells are plotted at the appropriate azimuth and radial distance (Zoback et al., 2003). The principal stresses are in vertical and horizontal planes. The stress magnitudes assumed for each set of calculations are shown in Table 1

![Figure 11](image)

**Figure 11:** Minimum Required mud weight (in s. g.) to prevent from collapse failure and tensile fracture for normally pressure zone A (a, b respectively) and for abnormally pressured zone B (c, d respectively) for arbitrarily oriented wellbores and in-situ stress in normal faulting regime. The colours indicate the magnitude of mud weight (s. g.) required to induce collapse failure and tensile failure of the wellbore wall.

In a normal faulting environment (Cambay basin) at depth A and B (Figure-4), breakout initiation occurs in wells that are highly deviated in the direction of $S_h$ than for vertical wells. Highly deviated wells in the $S_h$ direction are more stable than vertical wells. For horizontal wells drilled parallel to $S_h$, the greatest principal stress, $S_h$, pushes down on the well and the minimum principal stress, $S_n$, acts in a horizontal direction normal to the well path. For horizontal wells drilled parallel to $S_n$, $S_n$ pushes down on the well, but $S_h$ acts in a horizontal plane normal to the well path, resulting in a lesser stress concentration on the wellbore wall (Zoback et al., 2003; Zoback, 2007)

---

**Nomenclature**

- Axial borehole co-ordinate = $z$
- Borehole radius = $a$
- Weight of the overburden = $s$
- Poisson's ratio = $n$
- Wellbore pressure = $P_w$
- Pore pressure = $P_o$
- Maximum horizontal stress = $S_H$
- Minimum horizontal stress = $S_h$
- Radial, tangential and axial stresses = $r$, $s$, $z$
- Shear stresses = $t$, $t$, $t$
- The horizontal in-situ stresses = $s$, $s$, $s$
- Cartesian co-ordinates = $x$, $y$, $z$
- Radial distance from centre of the wellbore = $r$
- Angle around wellbore with respect to x axis = $q$
- Coefficient of internal friction = $m_i$
- Overburden stress = $S_v$
Conclusion

This study helps us to simulate breakout zone at different depths of interest in various geological conditions like over-pressured zones, HPHT conditions and in under-balanced conditions, i.e. with a mud weight below the reservoir pressure. The variation in magnitude and orientation of concentrated S_v from one position to another position in a basin affects the size and shape of breakout zone. Lower rock strength would result in a larger failure zone. The failures in relation to borehole inclination, azimuth, and mud pressure show the stability of inclined wellbores passing through abnormally stressed formations. Highly deviated wells in the S_h direction are more stable than vertical wells. This study is crucial for estimating wellbore fracture pressure and collapse pressure, thus a required mud weight window for optimizing a stable wellbore trajectory in sedimentary basins with different tectonic settings.

Nomenclature

Radial, tangential and axial stresses = \( \sigma_r, \sigma_t, \sigma_z \)

Shear stresses = \( \tau_{rr}, \tau_{rt}, \tau_{rz} \)

The horizontal in-situ stresses = \( \sigma_s, \sigma_h \)

Cartesian co-ordinates = \( x, y, z \)

Radial distance from centre of the wellbore = \( r \)

Angle around wellbore with respect to x axis = \( \theta \)

Coefficient of internal friction = \( \mu_i \)

Overburden stress = \( \sigma_v, S_v \)

Axial borehole co-ordinate = \( z \)

Borehole radius = \( a \)

Weight of the overburden = \( \sigma_z \)

Poisson's ratio = \( \nu \)

Wellbore pressure = \( P_w \)

Pore pressure = \( P_o \)

Maximum horizontal stress = \( \sigma_h, S_h \)

Minimum horizontal stress = \( \sigma_s, S_s \)
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Annexure 1

Stress transformations

For any arbitrarily oriented wellbore, principal in-situ stresses $\sigma_x$, $\sigma_y$, $\sigma_z$ are to be transformed to a new Cartesian coordinate system (x-y-z). The direction of new stress components are given by wellbore inclination from vertical $\gamma$, geographical azimuth, $\phi$ and the wellbore position from the X-axis, $\theta$ as shown in Figure-5a. The Y-axis is always parallel to the plane formed by $\sigma_x$ and $\sigma_y$. The following equations define all the transformed stress components (Aadnøy, 1987; Aadnøy and Looyeh, 2011):

$$
\begin{bmatrix}
\sigma_x \\
\sigma_y \\
\sigma_z
\end{bmatrix} =
\begin{bmatrix}
\cos^2 \phi \cos^2 \gamma & \sin \phi \cos^2 \gamma & \sin \gamma \\
\sin \phi & \cos \phi & 0 \\
\cos^2 \phi \sin^2 \gamma & \sin \phi \sin^2 \gamma & \cos^2 \gamma
\end{bmatrix}
\begin{bmatrix}
\sigma_x' \\
\sigma_y' \\
\sigma_z'
\end{bmatrix}
$$

(16)

$$
\begin{bmatrix}
\tau_{xy} \\
\tau_{xz} \\
\tau_{yz}
\end{bmatrix} =
\begin{bmatrix}
\cos \phi & \sin \phi & 0 \\
\sin \phi & \cos \phi & 0 - \sin \gamma \\
\cos \phi & \sin \phi & - \sin \gamma
\end{bmatrix}
\begin{bmatrix}
\sigma_x' \\
\sigma_y' \\
\sigma_z'
\end{bmatrix}
$$

(17)

Annexure 2

Kirsch equations:

Stresses around the wellbore are given by the Kirsch elastic solution. It takes into account two horizontal in-situ stresses, the axial stress, and mud weight ($P_w$) (Aadnøy, 1987; Aadnøy and Looyeh, 2011). The total stresses acting in the plane are:

$$
\sigma_r = \frac{1}{2} \left( \sigma_x + \sigma_y \right) \left( 1 - \frac{a^2}{r^2} \right) + \frac{1}{2} \left( \sigma_x - \sigma_y \right) \left( 1 + \frac{a^4}{r^4} - 4 \frac{a^2}{r^2} \right) \cos 2\theta + \tau_{xy} \left( 1 + 3 \frac{a^4}{r^4} - 4 \frac{a^2}{r^2} \right) \sin 2\theta + \frac{a^2}{r^2} P_w
$$

(18)

$$
\sigma_\theta = \frac{1}{2} \left( \sigma_x + \sigma_y \right) \left( 1 + \frac{a^2}{r^2} \right) - \frac{1}{2} \left( \sigma_x - \sigma_y \right) \left( 1 + \frac{a^4}{r^4} \right) \cos 2\theta - \tau_{xy} \left( 1 + 3 \frac{a^4}{r^4} \right) \sin 2\theta - \frac{a^2}{r^2} P_w
$$

(19)

$$
\tau_{r\theta} = \frac{1}{2} \left( \sigma_x - \sigma_y \right) \sin 2\theta + \tau_{xy} \cos 2\theta \left( 1 - 3 \frac{a^4}{r^4} + 2 \frac{a^2}{r^2} \right)
$$

(20)

where $r$ is the distance away from the axis of the borehole. Hoop stress at the borehole wall is described by equation (19) when $a = r$. 

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References

Deciphering Present Day Stress through New Generation Image Logs in Cauvery Basin

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Introduction

Borehole Breakouts and Drilling Induced Fractures (DIF) are important indicators of horizontal stress orientation, particularly in aseismic regions in petroleum and geothermal systems. In-situ stresses define the local forces acting on lithological layers in the subsurface. Knowledge of magnitude and direction of these stresses is important in drilling, wellbore-stability, and especially hydraulic-fracturing applications. The in-situ stresses acting on a formation can be decomposed into three principal compressive stresses, one vertical and two horizontal. The vertical stress is caused by the overburden weight acting on the top of a formation. The horizontal stresses are the result of the poroelastic deformation of the rocks plus externally applied tectonic forces. These two horizontal compressive stresses are usually not equal. The parameters that affect the magnitude of the in-situ stress include overburden weight, fluid pore pressure, porosity, anomalies in the rock fabric (i.e. natural fractures), and rock mechanical properties (such as Poisson's ratio), and tectonic activity.

The in-situ stress magnitude and direction can impact decisions and designs throughout the drilling and completion of a well. During drilling, in-situ stress may affect the mud and cement densities required to prevent unwanted fracturing of open-hole strata in the wellbore. For wells that will be stimulated at high pressures, casing design must account for the maximum anticipated stresses.

It is effective on wellbore-stability calculations, flow unit patterns, fluid flow in fractured reservoirs, cap rock failure and fault reactivation. Especially for horizontal wells, require knowledge of in-situ-stress magnitude and direction. For hydraulic-fracture treatment applications, the in-situ stresses control fracture azimuth and orientation (vertical and horizontal), fracture-height growth, fracture width, treatment pressures, and fracture conductivity.

Recognition of relationship between the present day stress state and fractures is having very significant role in fractured reservoirs. Fractures grow perpendicular to the minimum in-situ-stress direction; thus, stress direction can affect well-placement and spacing decisions. Because fracture-height growth and fracture width affect propped-fracture half-length for a given treatment size, stress is a critical parameter in fracture treatment modelling, design, and optimization. Natural fractures that are parallel or oblique to maximum horizontal stress have more tendencies to tensile deformation and tensile deformed fractures will be more permeable.

The present study (figure-1) is focused in the northern part of the Cauvery Basin encompassing the four sub-basins viz. Ariyalur-Pondicherry, Tanjore, Tranquebar and Nagapattinam where recent successes in Basement-Exploration have given more impetus to this area. The fractures oriented in present day stress direction are of more importance for predicting the producibility of fractured reservoirs viz. Basement.

Reasons for occurrence of DIFs and Borehole Breakouts

Borehole Breakouts are stress-induced enlargements of the wellbore cross-section. When a wellbore is drilled the material removed from the subsurface is no longer supporting the surrounding rock. As a result, the stresses become concentrated in the surrounding rock (i.e. wellbore wall). Breakout happens when the circumferential stress concentration around the borehole is more than compressive strengths of the rock (figure-2). This causes pieces of borehole wall to spall off and enlargement of the wellbore. The stress concentration around a vertical borehole is greatest in the direction of the minimum horizontal stress (SHmin). Hence borehole breakouts are oriented approximately perpendicular to the maximum horizontal compressive stress (Shmax).
DIFs happen when the circumferential stress around the wellbore is more than tensile strength of the wellbore wall. The stress concentration around a vertical borehole is minimum in SHmax direction. Hence, DIFs develop approximately parallel to maximum horizontal stress (SHmax). Induced fractures have some characters that make it different from the natural fractures, for example: these are narrow and sharply defined features parallel or sub-parallel to the wellbore (in vertical well), occurs around the borehole wall only (no deep penetration), indicates present day stress direction.

During drilling, the mud replacing the rock perturbs the stress around the wellbore causing the stress (compressive or tensile) development. The mud weight, to some extent, controls the failure of rock in the wellbore wall. If mud weight is too high then formation contamination and DIF appears. If mud weight is too low then borehole wall collapse and well blow out will be brought out. Therefore mud pressure should be a little higher than pore-fluid pressure but lower than fracture pressure.

### Methodology

In the present study, Borehole Breakouts and Drilling Induced Fractures have been identified in 11 wells through extensive processing and analysis of available micro-resistivity image log data in Basement or overlying sections. These recognized features have been further analysed to estimate their directions for evaluation of present day stress orientation. The technique, which has been used for determination of in-situ stress direction, is based on analysis of Borehole Breakouts and Drilling Induced Fractures through borehole micro-resistivity image logs (FMI). Borehole Breakouts and Drilling Induced Fractures are important indicators of horizontal stress orientation, particularly in aseismic regions at intermediate depths (less than five kilometres).

In the following lines, the methodology of identification and interpretation of DIFs and borehole breakouts from image data adopted in the study has been discussed in details.

Resistivity Imaging Tools provide an image of the borehole wall which is typically based on physical property contrasts of the formation rock. The Resistivity Imaging Tools have evolved from Dipmeter tools and consists four or six calliper arms with each arm ending with one or two pads containing a number of resistivity buttons.

As FMI tools are electrical, it can be used in water based (conductive) drilling mud. In drilling processes, hydrostatic pressure of drilling mud is higher than formation pressure then mud can penetrate in open fractures. High conductivity of penetrated water base mud causes open fractures to be black in image log. Each electrode in FMI tool measures electrical properties of the formation separately.
Resistivity Image Tools provide the same information on borehole diameter and geometry as the older dipmeter tools, and hence this data can be used to interpret breakouts in the same way as for four-or six-arm calliper logs. However, the resistivity buttons also allow high-resolution image of the wellbore wall based on resistivity contrasts and this allows for the direct observation of borehole breakout.

Borehole Breakout typically appears on resistivity image logs as broad, parallel, poorly resolved conductive zones separated by 180° i.e. observed on opposite sides of the borehole and often exhibiting calliper enlargement in the direction of the conductive zones. Breakouts are typically conductive and poorly resolved because the wellbore fracturing and spalling associated with the breakout results in poor contact between the tool pads and the wellbore wall, which in turn causes the tool to partially or fully measure the resistivity of the electrically conductive drilling mud rather than the formation. However, it is important to note that breakouts will appear as resistive, rather than conductive, zones in resistivity images run in oil-based mud.

In the present study, 1) only those separations on calliper logs have been considered for breakout identification where at least one calliper log (out of 2 or 3) reads the bit size, 2) only those signatures of breakouts on image have been considered where breakout direction on image matches with direction of enlarged calliper as indicated by pad 1 azimuth.

Drilling Induced Fractures can only be observed on Image logs. DIF’s typically become infiltrated by drilling mud and thus appear on resistivity logs as pairs of narrow, well defined conductive features (resistive in oil based mud) separated by 180°. Furthermore, unlike natural fractures that tend to cross-cut the wellbore, DIF’s are usually aligned sub-parallel or slightly inclined to the borehole axis in vertical wells. In this study, some DIFs identified on one pad image might not have appeared on opposite pad and still has been considered after scrutinising image quality and borehole condition.

**Discussion of Interpreted Results**

The study area encompasses four Sub-Basins viz; Ariyalur-Pondicherry, Tanjore, Tranquebar and Nagapattinam, where the Basement is extensively explored and found to be hydrocarbon bearing.

In Ariyalur-Pondicherry Sub-Basin, 1 well of Chidambaram Field and 4 wells of Pandanallur field have been studied. Present day principal stress direction swing from NE-SW to NNW-SSE direction in this Sub basin. To be more precise it is in the direction of NE-SW, NNE-SSW and NNW-SSE (figure-3a, 3b, 3c).

Drilling Induced Fractures (DIF) in interval 4078.5-4079.5m in well A, in Ariyalur-Pondicherry sub basin, oriented towards NE-SW direction indicating present day principal stress direction.

Drilling Induced Fractures (DIF) in interval 2679.5-2681m in well B, in Ariyalur-Pondicherry sub basin, oriented towards NNE-SSW direction indicating present day principal stress direction.

![Figure: 3a](image1.png)

![Figure: 3b](image2.png)
Resistivity Image Tools provide the same information on borehole diameter and geometry as the older dipmeter tools, and hence this data can be used to interpret breakouts in the same way as for four-or six-arm caliper logs. However, the resistivity buttons also allow high-resolution image of the wellbore wall based on resistivity contrasts and this allows for the direct observation of borehole breakout.

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The Tanjore Sub-Basin includes 1 well of Mattur and 3 wells of Pundi field. The direction of present day principal stress is in NNE-SSW, N-S and NNW-SSE in this Sub-Basin (figure-4a, 4b, 4c).

In Tranquebr Sub-Basin 2 wells of Madanam field have been considered for study. The direction of present day stress is in to be in NE-SW, NNW-SSE and NW-SE direction in this Sub basin (figure-5a, 5b, 5c).

The Nagapattinm Sub-Basin includes Periyakudi field where overlying section of basement has been studied. The direction of present day stress is NNW-SSE in this Sub basin (figure-6).
The general observation from the above analysis is that gross direction of present day principal stress in Northern part of Cauvery Basin lies along NNW-SSE direction. This is particularly true in studied wells of Chidambaram, Periyakudi and Mattur fields. This observation is in accordance with earlier studies (Gowd T N, 2005 & Chatterjee R. et al., 2001). They observed that overall regional stress direction (SHmax) in the studied area (Northern part of Cauvery Basin) is NW (figure-7 & 8).

In present study, some local variations in current stress directions are observed in Pundi, Pandanallur and Madanam area not only with respect to regional stress orientation but among studied wells of same field also. Local stresses may differ significantly in orientation and/or magnitude from regional stresses due to folding, faulting, lithological differences, digenesis, pore-pressure variations and other influences. The stress vector changes direction at the interfaces between geologic layers with different elastic properties. Chatterjee et al., 2003 observed that in both KG and Cauvery Basins, the horizontal stress has deflections in the basinal sediments that are largely determined by the geometry of upper crustal competent layers and by horst-graben structure & faulting.

Lateral variation of stress orientation may be attributed to presence of different stress regimes caused by location of these wells in different fault blocks as well as proximity of a well near the fault. Direction of DIFs follows the azimuth of adjacent fault plane as is observed in one well of Madanam Field (Lakhera et al., 2015).
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Vertical variation of stress direction seems to be due to insufficient vertical extension of nearby fault or may be because of orientation of contiguous fault plane in respect of borehole axis. Another reason may be presence of different adjoining faults at different depths. Also, lithological changes resulting in variation in rock properties may also have some bearing. These inferences require validations through critical assessment of good quality seismic data.

Broad features of stress map of Indian subcontinent. (Published by Goud et al., 1992)

Stress distribution showing the orientation of maximum Horizontal comprehensive stress for Cauvery Basin (Courtesy: Chatterjee R, et al., 2001)
Inferences

The present day principal stress direction swings from NE-SW, NNE-SSW and NNW-SSE in Ariyalur-Pondicherry Sub Basin while in Tanjore Sub-Basin it is in NNE-SSW, N-S and NNW-SSE direction. In Tranquebr Sub-Basin stress direction is NE-SW, NNW-SSE and NW-SE whereas it is oriented in NNW-SSE in Nagapattinm Sub-Basin. The study shows that overall (regional) present day principal stress orientation in the studied wells of Cauvery Basin is in NNW-SSE (figure-9) with some local variation trending from NW-SE to NE-SW as observed laterally as well as vertically.

The local variations may be caused by location of wells in different fault blocks and also their positions with respect to faults.

Vertical variation of stress orientation as observed in a studied well may be due to less vertical extension and/or orientation of nearby faults, or may be due to presence of multiple faults.

Occurrence of DIF and/or breakout in a well depends on failure of rock in the wellbore wall which to some extent is controlled by drilling mud weight and rock mechanical properties.

Barefoot testing data from basement in recently drilled wells in this area validates the identified present day stress direction in the study.

Data acquired through image tools having more azimuthal coverage gives additional support to deduce the breakouts & their orientations through caliper logs (figure-10). Also, if circumferential coverage by the pads

Drilling Induced Fractures (DIF) in interval 2735-2737m (in one of the well of Cauvery Basin) oriented towards NNW-SSE indicating present day principal stress direction.

Borehole-Breakouts in interval 2942.5-2945m (in one of the well of Cauvery Basin) oriented towards WNW-ESE, indicating NNE-SSW as present day stress direction.
**Conclusions**

The study will help in selecting orientation of hydro-fracturing and direction of horizontal wells for enhanced productivity especially for Basement reservoirs.

It will also facilitate to have a better understanding of critical fracture orientation to estimate reservoir productivity.

**References**


Tracking the Clastic Channel through Comprehensive Formation Evaluation of Conventional Logs in A Varying Depositional Environment

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Abstract

It is often difficult to evaluate a formation with lithological variations where depositional environment is changing rapidly. The characterization of these reservoirs would have more uncertainties in the absence of hi-tech logs and core data for making comprehensive petrophysical model and calibrating the evaluation.

L-I layer is the shallowest reservoir in Mumbai High Area. It is basically divided into three sub-layers, L-Ia, L-Ib and L-Ic, based on log characters. In most of the wells, L-I layer is falling either in 12.25" or 17.5" borehole and minimum log data could only be collected, with spectral Gamma ray data only in two wells. There is a clear difference between the log characters of upper sub-layers (L-Ia and L-Ib) and lower sub-layer L-Ic. As indicated by Neutron and Density logs, both are having good reservoir characters but Gamma Ray log and PEF log are suggesting a different depositional environment for both. L-Ic shows higher Gamma-Ray activity and lower PEF values than L-Ia and L-Ib. This suggests that L-Ic has been deposited in a clastic environment. Cross-plots of various logs suggest that L-Ia and L-Ib are carbonate layers while L-Ic has a sand-silt lithology. Taking all this into consideration, a unified petrophysical model was developed specifically for L-I. ECS data from a well of nearby field also corroborates to the developed interpretation model.

The interpretation facilitated sub-layer wise mapping of reservoir properties and helps in sub-layer wise development plans. The analysis of correlation profiles along with interpretation results suggests that an E-W channel, with medium clastic input appears to have deposited the L-Ic reservoir in low energy conditions while the extensive L-Ib layer has an N-S orientation. Few prospective areas have also been brought out from this study.

Introduction

Mumbai High is an offshore oil field (Fig 1) in water depth of 80m in the Arabian Sea and 160 Km west–north-west of Mumbai city. Mumbai High has three blocks separated by east-west trending faults. Mumbai High offshore field is divided into MHN and MHS due to the presence of structural low between the two sectors. Mumbai high main producing section consists of a number of layers (L-I to L-VI), some of which are limestone layers with intervening sandstone layers. Though L-III reservoirs, with many sub-layers, is the main contributor to the production from this field, L-I reservoir appears to be a good candidate for augmenting the production.

Generalized stratigraphy

L-I layer is of Mid. Miocene age and occurs in Bandra Formation, overlain by Chinchini formation (Fig 2). This layer appears to have a mixed depositional environment; partially clastic and partially carbonate (Fig.3).
Study Approach

1. An integrated petrophysical model has been developed using log data and mineralogical inferences from cross-plots (Fig.4 & 5). Some core studies and ECS data from adjacent area, viz. Mumbai High North were also considered in the absence of cores/core studies in the study area to synthesize Petrophysical interpretation model for L-I reservoir.
2. L-Ia and L-Ib are interpreted with mainly limestone facies and montmorillonite as clay mineral. L-Ic has a clastic depositional environment, as envisaged and is differentiated from above limestone layers with PE logs (Fig.6). A sand-silt model with montmorillonite as clay mineral is used to evaluate this sub-layer. Shale sections have also been modeled taking quartz along with montmorillonite.
3. Gas and oil both have been included as fluids in the reservoir model with GOC based on lowest known level of gas occurrence in testing results.
4. Petrophysical evaluation was carried out for all three sub-layers developed within L-I reservoir after corroborating the computed Petrophysical parameters with available testing data. Average reservoir parameters are computed for individual sub-layers. Mapping of reservoir parameters is taken up for each sub-layer.

Discussions

1. In the studied wells, a shale break is a common feature between calcitic L-Ib sub-layer and clastic L-Ic sub-layer, where an abrupt change of depositional environment is observed. This phenomenon is uncommon in MHN area.
2. The carbonate sub-layer L-Ia has thickness of typically 1-2 m and is developed poorly in the entire study area. L-Ib is present throughout the study area and the reservoir quality and thickness are promising in most of the wells. It is most prolific amongst the three sub-layers. Average porosities are in a range of 20-25% for this sub-layer with good isopay (Fig.6).
3. A selective area in MHS shows better development of clastic sub-layer L-Ic.
4. The analysis of prepared isopay maps suggests that an E-W channel, with medium clastic input appears to have deposited the L-Ic reservoir in low energy conditions while the extensive L-Ib layer has an N-S orientation (Fig.7 and Fig.8).

Conclusions

1. A unified petrophysical model was developed to interpret the L-I reservoir in study area by integrating all available G&G data.
2. Prospective areas have been identified for L-Ib and L-Ic.
3. An E-W channel, with medium clastic input appears to have deposited the L-Ic reservoir in low energy conditions while the extensive L-Ib layer has an N-S orientation
4. The low resistive L-Ic sub-layer needs more attention by collecting and analyzing more representative G&G data.
5. The developed integrated model can be further refined with representative core data, production testing, formation water salinity and PLT data.

References

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Acknowledgement

Authors express their sincere gratitude to ONGC management for giving the permission to publish this paper.
**Figure 1:** Study Area

**Figure 2:** General Stratigraphy

**Figure 3:** Log characters distinguishing three sub-layers within L-I

**Figure 4:** Points corresponding to L-Ic fall far from Limestone line and suggest a classic depositional environment

**Figure 5:** Cross-plots for clay mineralogy indicate Montmorillonite as the main clay

**Figure 6:** Comprehensive formation evaluation bringing out HC bearing layers for both carbonate and clastic reservoirs

**Figure 7:** Isopay map for L-Ib of Mumbai High South

**Figure 8:** Isopay map for L-Ic of Mumbai High South
**Figure 5:** Cross-plots for clay mineralogy indicate Montmorillonite as the main clay

**Figure 6:** Comprehensive formation evaluation bringing out HC bearing layers for both carbonate and clastic reservoirs

**Figure 7:** Isopay map for L-Ib of Mumbai High South

**Figure 8:** Isopay map for L-Ic of Mumbai High South
Prediction and Demarcation of High Pressure and High Temperature (HP-HT) Areas Using Wire Line Logs: A Case Study in Krishna Godavari Basin

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Abstract

KG Basin is well known for its drilling complications arising out of formations with High Pressure and High Temperature (HP-HT). It often encounters problems like kicks, mud loss, wellbore instability and even blowout. Drilling engineers are in thirst of getting accurate knowledge of formation pressure and temperature so that they can design proper mud weight in order to cope up with all the above mentioned challenges. In the present study, a set of continuous pore pressure gradient, fracture gradient, over burden gradient and temperature gradient data have been generated through well logs and Bottom Hole Temperature (BHT) data for over 40 wells of KG Basin. Logs such as Gamma Ray (GR), Density (RHOB) and sonic travel time (DT) have been used in computing pore pressure, fracture pressure and over burden pressure gradients. Pore pressure gradient were calibrated with formation pressure data such as MDT, etc. whereas, Fracture Gradient (FG) were calibrated with LOT (Leak-Off Test) data. The estimated pore pressure gradient, fracture gradient, over burden gradient and temperature gradient were used for generating isobar, isotherm and isopach maps for analyzing and predicting the trend of variation in pressure and temperature across the basin. Through these maps, High Pressure (HP) and High Temperature (HT) trends were analyzed and these were then used to predict HP and HT areas in KG Basin.

Introduction

Prior knowledge of formation pressure and temperature is essential for successful drilling and completion of a well. It is also necessary to carry out successful open hole logging operations as the logging tools are designed to operate within specified range of pressure and temperature. In addition to that, logging tool string is more prone to get stuck up in high pressure well than in a normal pressure well. Accurate knowledge of formation pressure and temperature helps in designing proper mud weight which yields to prevent kicks, formation damage, circulation loss, borehole collapse and even blowout. The knowledge of predrill formation pressure and temperature are more essential in case where the wellbore falls under a high pressure regime as a high pressure well poses more unforeseen problems than that of a well with normal pressure. If drilling engineers have pore pressure data with them that will be of immense use because from pore pressure data, they can select the proper mud weight window in order to reduce unwanted incidents and can safely drill and complete a well.

Hydrostatic Pressure at a depth is the pressure exerted by the weight of a static column of fluid from surface to the desired depth.

\[ P_{hyd} = h \cdot g \]  \hspace{1cm} (1)

Where, \( h \) = height of fluid column, \( \rho \) = Density of fluid and \( g \) = Acceleration due to gravity.

Overburden Pressure is a pressure exerted by the weight of overlying sediments, including the weight of the pore fluids.

\[ OBG = \int (g)dh \]  \hspace{1cm} (2)

Here \( \rho \) is the bulk density.
Pore pressure is defined as the pressure exerted by the fluid contained in the pore space. Pore pressure can be categorized as i) normal, ii) subnormal, and iii) abnormal pressure. As total overburden stress (OBG) is jointly supported by the pore fluid and the rock matrix (Terzaghi's Relationship, 1943), therefore,

\[
\text{Overburden Pressure (OBG)} = \text{Pore pressure (PP)} + \text{Effective Vertical Stress} (\sigma_{ev})
\]

Or, \( PP = OBG - \sigma_{ev} \) ........................ (3)

Where, effective vertical stress is the stress applied to the rock matrix.
Fracture Pressure is pressure required to initiate a fracture in the formation. It is also known as fracture initialization pressure (FIP), fracture opening pressure (FOP) or rupture pressure.

**Methodology**

a) **Shale discrimination**: Natural Gamma Ray (GR) log (with the help of resistivity log also) has been used to discriminate shale out of sand and this was projected on sonic transit time (DT) curve which gives shale points on DT.

b) **Normal Compaction Trend (NCT)**: Once shale points are generated on DT, appropriate filter has been applied on these shale points in order to smoothen the shale discriminated DT. Then Normal Compaction Trend (NCT) was generated to know the normal trend of the acoustic compressional slowness using Miller method.

c) **Density profile**: As density log is required in the entire interval of the well under study to determine overburden stress, synthetic RHOB log (\( \rho \)) was generated from DT by Gardner method (Eq. 4). In the interval where density (RHOB) log was not recorded. Miller method has been used to calculate RHOB from MSL to mudline where DT is not recorded.

\[
\rho = A(10^6/DT)^B
\]

Where, \( \rho \) is in g/cc and DT is in us/ft; A and B are constants and have default value 0.23 and 0.25 respectively. These synthetic RHOB logs were then merged with the original wireline density log to generate density curve for entire interval of the well.

d) **Over Burden Gradient (OBG)**: By integrating density log over the entire interval of the well, Over Burden Gradient (OBG) was obtained (Eq. 2).

e) **Pore pressure gradient**: By using Eaton’s method pore pressure gradient was estimated by using following equation:

\[
PP = OBG - (OBG - PP_n)(DT/DT_n)^m
\]

Where,

- PP = Pore Pressure Gradient (PPG)
- OBG = Overburden Gradient (PPG)
- \( PP_n \) = Normal Pore Pressure Gradient (PPG)
- DT = Observed Interval Transit Time, (usec/ft)
- \( DT_n \) = Normal Interval Transit Time, (usec/ft)
- m = Eaton Exponent.
f) Fracture Gradient (FG): Fracture Gradient (FG) was determined by Mathew & Kelly (MK) method.

\[ FG = PP + (OBG - PP)Ki \]  \( ...............(6) \)

Where,
\( Ki = \) Matrix Stress Coefficient.

The estimated pore pressure and fracture pressure were compared with mud data and calibrated with MDT and LOT data.

A comparison were made between the estimated pressure gradients and and 'D'-exponent data recorded during drilling.

g) Generation of Maps: High pressure zones were identified for each of 40 wells and maximum values of pore pressere gradient, fracture gradient, over burden gradient, and temeprature values were noted and corresponding depths is also noted. Isobar maps of PP, FG and OBG were genereated to identify and demarcate the high pressure areas whereas Isotherm map is generated to identify and denarcate high temperature areas.

Results and Discussions

Adopting above mentioned methodology, well composites showing pressure gradient data along with log curves have been generated for all the 40 wells. An example is shown below for the Well-6:

Figure 1: Pore pressure, fracture, overburden and temperature gradients plot (Well-6)

As per the study, the pore pressure appears to deviate from normal regime to high pressure regime at 3490m. The high pressure regime extends up to the depth 4105m whereas it reaches to maximum of 14.19 ppg at the depth 3862m. Corresponding fracture and over burden pressure gradients against this depth are 17.46 ppg and 19.31 ppg respectively.
Fracture Gradient (FG) was determined by Mathew & Kelly (MK) method.

\[
\text{FG} = \text{PP} + (\text{OBG} - \text{PP}) \times \text{Ki}
\]

Where,

\(\text{Ki} = \text{Matrix Stress Coefficient.}\)

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It is clear from the 'D'-exponent and shale density data that the high pore pressure zone obtained from present study is in very good agreement with the 'D'-exponent and shale density data.

**Histogram Analysis**

Based on the analysis of the well-wise gradient data, abnormal pressures have been observed in the wells at and around the top of the Synrift sequences (i.e. HG-HR sequence). The high pressure zones begin either at the HG-HR sequence top or above it within the Raghavapuram Shale sequence.

A SW-NE profile of pressure distribution of the wells has been prepared across the basin in the southern and northern area (Fig.4) which shows transitional and high pressure distribution in Northern and Southern area.

It is observed that the pore pressure values are lower in the SW part of the basin but the pressure values start increasing towards the eastern side and the highest pore pressure values are encountered in the Vygreshwaram-Kottalanka area. There is no exact trend across the basin but the most important observation is that in all the wells the overpressure starts occurring within Raghavapuram shale or its lower part (i.e. HG-HR shale).
The temperature values have been plotted across the basin (Fig. 5). The temperature distribution shows no conformity with the pressure distribution in the Basin. The maximum temperature is observed in the Kottalanka, which also has the highest pressure but it does not follow the high pressures in the nearby areas. In fact, some of the wells have high pressures but low temperatures.

**Generation of maps and trend analysis**

The pore pressure and temperature gradients computed from logs were used to generate maps to establish a regional trend of pressure and temperature. Well-wise pore pressure gradient, fracture

**Figure 4:** Transitional and high pressure distribution in Northern and Southern area.

The temperature values have been plotted across the basin (Fig. 5). The temperature distribution shows no conformity with the pressure distribution in the Basin. The maximum temperature is observed in the Kottalanka, which also has the highest pressure but it does not follow the high pressures in the nearby areas. In fact, some of the wells have high pressures but low temperatures.

**Figure 5:** Temperature distribution in Northern and Southern part of the basin.
The temperature values have been plotted across the basin (Fig. 5). The temperature distribution shows no conformity with the pressure distribution in the Basin. The maximum temperature is observed in the Kottalanka, which also has the highest pressure but it does not follow the high pressures in the nearby areas. In fact, some of the wells have high pressures but low temperatures.

Gradient, overburden gradient were calculated and from the pore pressure curve PP maxima against transition pressure zone, high pressure zone were estimated. The depth corresponding to these values were noted to get the exact location of maximum pressure in the well. In case of well with normal pressure, the maximum pressure recorded in the well and the corresponding depth was collected. As per industry standards, pressure ~10000 psi considered as the criteria for selection of high pressure wells. Hence, the depth at which the wells encountered 10000 psi was noted. These data have been used to generate various maps as discussed below.

**Regional Isobar Map**

The regional isobar map brings out variation in pressure across the basin. In general, the high pressure is encountered in grabenal areas. In the NE part of the basin, rapid rise in pressure is observed south of Poduru-Yanam High and MTP-PLK fault, (Fig. 6).

![Regional Isobar Map](image)

**Figure 6: Regional Isobar Map**

**Regional Isotherm Map**

The regional isotherm map shows the variation in temperature across the basin. From this map it can be said that temperature is higher in Grabenal part and lower in Horst areas. However, in the NE part of the basin rapid rise in temperature and pressure is observed in Kottalanka area (Fig. 7).
Regional Maximum High Pressure Depth Map

The regional maximum high pressure depth map brings out variation in the depth of occurrence of high pressure/maximum recorded pressure across the basin. It shows a well-wise general trend of depth of occurrence of pressure. In general, in the grabenal areas, the depth of occurrence of high pressure increases and in horst areas very shallow depth is noted. It may be because of lesser thickness of sediments and/or shallow depth of drilled wells in the horst areas.

The stratigraphic level corresponds to these depth are established and it shows the high pressure is cutting across different stratigraphic level. Out of 40 wells studied, high pressure/maximum pressure at the drilled depth is observed in Raghavapuram shale (7 wells), HGHR unit (14 wells), synrift section/sequence (14 wells), Mandapeta and Kommugudem (4 wells) formations (Fig.-8).
Overlay of Regional Temperature on Pressure

To establish the relationship between the temperature and pressure an overlay is prepared. The recorded regional temperature map is overlain on the regional pressure map. On the map a general correlatable trend is observed, i.e., most of the high pressure areas are exactly falling on the high temperature areas with exceptions in few wells (Fig.9).

![Figure 9: Overlay of Regional Temperature on Pressure](image)

Depth map at 10000 psi Datum

The wells which have encountered high pressure (~10000 psi) were shortlisted and the depth map was prepared using corresponding depth at which 10000 psi originated. From the 40 wells originally considered, around 18 wells have encountered pressure more than/ around 10000 psi. It is observed that 10000 psi pressure is encountered at shallow depth in Kavitam areas. Similarly, in Suryaraopeta and Malleswaram areas, 10000 psi is expected at the depth deeper than that of Kavitam areas though the studied wells have not penetrated basement section. The increase in pressure may be expected below the drilled depth wherein sediment thickness is more (Fig.10).

![Figure 10: Depth map at 10000 psi](image)
Conclusions and Recommendations

Through the continuous pore pressure gradient determination through well logs, the study concludes that high pressure is observed in grabenal areas like in wells in Kavitam low. In the NE part of the basin, rapid rise in pressure is observed in the south of Poduru-Yanam High and Matsyapuri-Palakollu fault. The study concludes that deeper the depth higher the pressure and most of the high pressure areas concides with the high temperature areas with few exceptions. Based on this study, a safe mud window between pore pressure and fracture gradients may be used for drilling wells. From the results of this study and maps prepared, mud and casing policies can be designed before drilling the well. Also, zones delineated beyond the HP-HT regime can also be targeted for exploration purposes with lesser risk. It is also recommended that the acquisition and processing of future seismic data may be carried out for high pressure-zones at deeper depths.

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xii. WCRs/FE Rs of all the selected key wells.
Fluid Characterisation through Acoustic Studies on Core Samples: A case study in Gandhar and Jambusar Areas of Cambay Basin

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Summary

Acoustic velocity studies are of great interest in seismic as well as in petrophysical well log analysis. In clean reservoirs, type of fluid can be identified with reasonable accuracy from log analysis but their identification becomes difficult in complex and heterogeneous reservoirs. In such a scenario acoustic studies on core samples may provide a very effective mean to characterize the type of fluid; as the fluids present in the pore space of reservoir rock are known to have significant influence on acoustic parameters such as $V_p$, $V_s$, $V_p/V_s$ ratio, Poisson's Ratio and acoustic impedance. The present study shows a methodology to characterize the fluid nature through acoustic studies on core samples. Core samples in heterogeneous reservoirs of Gandhar and Jambusar area of Cambay Basin have been taken up as a case study. Acoustic velocities on sandstone core samples have been measured. To see the effect of different saturating fluids on $V_p/V_s$ ratio and Poisson's Ratio, the core samples were saturated with brine, air and oil. DSI log data has also been analysed and compared with the laboratory derived acoustic data for validation. A good match is observed. A number of $V_p/V_s$ cross plots were generated to distinguish between brine, oil, and gas saturated zones. An increase of 6 to 15% in $V_s$ at 3500 psi has been observed in brine saturated samples against oil saturated samples which implies that acoustic log can be used as fluid indicator. In Hazad sands of Gandhar area, for gas bearing zone $V_p/V_s$ ratio < 1.61 and PR value < 0.19 while for water bearing zone $V_p/V_s$ ratio > 1.67 and Poisson's Ratio> 0.22. Oil bearing zone may have $V_p/V_s$ values in the range 1.61-1.67 and Poisson's Ratio values in the range 0.19-0.22. Based on this study suitable transforms have been generated to distinguish gas, oil and water bearing zones. These transform will be very helpful in complex reservoir where characterization of fluids become difficult from logs alone.

Introduction

Acoustic velocity studies are of great interest in seismic as well as log interpretation. The compressional wave and shear wave velocity play an important role in identifying the fluid typing in reservoir rocks saturated with different fluids. Fluid identification in heterogeneous reservoirs rocks become more challenging as logs are unable to distinguish the fluid type. P-wave transit time data are very useful in identifying lithology, porosity and pore fluids. S-wave data are also useful for mineral identification and porosity determination. It is found that P-wave velocity decreases and S-wave velocity increase with the increase of light hydrocarbon in place of brine saturation. Laboratory approach has been attempted for fluid typing in the reservoir based on velocities and their ratios. There is expected to be considerable changes in the velocities when the rocks are saturated with different fluids. The $V_p/V_s$ ratio has been proposed as an indicator to determine fluid content. These studies state that the $V_p/V_s$ and Poisson's Ratio are lower in gas saturated rocks. Natural porous media are always saturated with fluids and the influence of these fluids on acoustic properties is essential. In this work we have measured the acoustic velocity on sandstone core to see the effect of different saturating fluids on $V_p/V_s$ ratio and Poisson's Ratio. DSI log data with laboratory derived acoustic data in Gandhar area has also been analysed. The field examples are provided to show how the $V_p/V_s$ crossplot can distinguish between brine, oil, and gas saturated zones.
Methodology

The acoustic studies have been carried out on ten core plugs of heterogeneous reservoirs of Hazad sand reservoirs of Gandhar and Jambusar fields. All the core samples were cleaned to remove hydrocarbons and salts by soxhlation process. After soxhlation process all core samples were dried at a temperature of 60°C centigrade. Next, the porosity, helium porosity, grain density and bulk density of individual core plugs were determined in the laboratory. The compressional wave velocity and shear wave velocity were measured by the AVS-700 equipment at different confining pressures with different fluid namely, air, brine and oil.

Study was carried out on the core samples in three stages. In the first stage, \( V_p \) & \( V_s \) measurements were made on dry core plugs i.e. air filled in pore spaces. Next, the measurements were made on core plugs saturated with brine of 20 gpl salinity, to measure \( V_p \) and \( V_s \). Finally in the third stage after soxhlation, for the removal of brine, samples were saturated with crude oil of 38 API grade. Detail acoustic measurements were carried out in all these three stages.

Results and discussion

The detailed analysis on the core plugs reveal the influence of different fluids (i.e. air, oil and brine) on acoustic properties. The velocity measurements versus pressure for air, oil & brine saturated sandstone show that the P-wave velocity at ‘air’ is lower than the oil saturated velocity, which is still lower than the velocity when rock is saturated with brine. The velocity increases in case of fully saturated rock with brine (Fig. 1). This is because of introduction of water into the dry sample due to which the pores become more difficult to compress, thereby, increasing the velocity. While the introduction of oil into the rock gives less change in velocity. It is also observed that S-wave velocity change very less for oil saturate rock to brine saturated rock.

Core plugs of heterogeneous reservoirs of Hazad sand reservoirs of Gandhar and Jambusar fields were analysed. The analysis of the variation of \( V_p/V_s \) with the confining pressure shows an increase of 6.3% in \( V_p/V_s \) ratio at 1000 psi from air saturated to brine saturated while this variation is very less at 1.9% from air to oil. When \( V_p/V_s \) ratio is plotted against acoustic impedance, it is seen that brine zone has high \( V_p/V_s \) ratio & high acoustic impedance (Fig. 2) as compared to gas saturated zone. This cross plot show better fluid identification along the impedance axis.

![Figure 1: Velocity vs. Pressure on core plug (A) Jamubsar area (B) Gandhar area](image1.png)

The study has established ranges of \( V_p/V_s \) ratio and Poisson's ratio for gas, oil and water bearing zone of Hazad sand in Gandhar & Jambusar area of Cambay Basin. For gas bearing zone \( V_p/V_s \) ratio < 1.61 and PR value < 0.19 while for water bearing zone \( V_p/V_s \) ratio > 1.67 and PR > 0.22. Oil bearing zone may have \( V_p/V_s \) values in the range 1.61-1.67 and PR values in the range 0.19-0.22.
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The above results have been validated with the available DSI log data and production testing data. Measured values of Vp/Vs and PR values derived from of DSI logs and Core studies are given in table

<table>
<thead>
<tr>
<th>Type of fluid</th>
<th>DSI Log Vp/Vs</th>
<th>PR</th>
<th>Laboratory measurement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>1.64-1.83</td>
<td>0.20-0.28</td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon (Gas)</td>
<td>1.52-1.62</td>
<td>0.16-0.19</td>
<td></td>
</tr>
<tr>
<td>Saline water</td>
<td>1.67-1.71</td>
<td>0.22-0.24</td>
<td></td>
</tr>
<tr>
<td>Air</td>
<td>1.58-1.61</td>
<td>0.17-0.19</td>
<td></td>
</tr>
</tbody>
</table>

Figure 3: Show the cross plot of Vp and Vs of different fluid at reservoir confining pressure. Through these studies transforms were generated to establish linear relationships. These are given below

Gandhar field (Hazad sand)

Vp = 1.74Vs - 115.0 for Brine
Vp = 1.56Vs + 132.5 for Oil
Vp = 1.63Vs - 66.71 for Air

Jambusar field (Hazad sand)

Vp = 1.78Vs - 203.56 for Brine
Vp = 1.58Vs + 73.83 for Oil
Vp = 1.62Vs - 63.99 for Air
Conclusions

The present work has led to a better understanding of core derived acoustic parameters vis-a-vis reservoir fluids. The study concludes that reservoir fluids namely gas, oil, water can affect the acoustic parameters such as $V_p$, $V_s$, $V_p/V_s$ ratio, Poisson's Ratio and acoustic impedance in different ways. These changes in acoustic parameters can be used to identify the fluid type through the generation of suitable transforms. These transforms, as the study shows, will be very helpful in identifying fluid character in heterogeneous and complex reservoir where characterization of fluids become difficult from logs alone. The study has established ranges of $V_p/V_s$ ratio and Poisson's ratio for gas, oil and water bearing zone of Hazad sand in Gandhar & Jambusar area of Cambay Basin. The approach, as shown in this study, can be an enabling factor in identifying suitable hydrocarbon bearing prospects for future exploration.

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References


Influence of Pore Aspect Ratio & Heavy Minerals in Rock Physics Modelling: A Case Study of Daman Formation in Tapti Area

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Abstract

An inclusion-based rock physics method is used for modelling the elastic logs recorded in a sand–shale sequence. Fixed values of pore aspect ratio are often used in modelling of elastic logs. Pore geometry (pore aspect ratio) can explain most of the scatter in porosity-velocity relationship which is considered to be one of the most important factor in velocity predictions (Xu & white 1995). Xu & White divides the total pore space into two parts, one associated with sand grains and other associated with clay platelets. In this study, a model with fixed aspect ratio of sand grains and clay platelets is used to predict elastic logs which is then compared with model of variable pore aspect ratio. The depth-dependent variation of pore aspect ratios can be used to get more consistent and corrected set of elastic logs. Moreover, the study also analyzes the effect of special minerals like pyrite, siderite in rock physics modelling to get insitu compressional and shear velocities for seismic reservoir characterization.

Introduction

Porosity and clay content are important factors in the estimation of the elastic logs of the rock, but pore aspect ratio (the ratio of the short to the long axis for sand grain and clay particles) is also an important parameter which influences the rock elastic property significantly. This factor varies with respect to depth due to overburden pressure of sediments but most of the time this is considered to be constant over the whole depth range.

The study utilizes Xu & White model based on Kustor & Toksoz assumption, Differential Effective Medium (DEM) theory and Gassman's theory to predict shear and compressional wave velocities. The rock physics model is to be built in four steps, first modelling the minerals properties, secondly to model the fluid properties then modelling the rock frame and finally assembling the three components where the bulk & shear modulus of mineral mix, fluid mix and dry rock frame are estimated on basis of Kustor & Toksoz model, Differential Effective Medium (DEM) theory. Gassman's equations are used for prediction of compressional and shear velocities in saturated rock.

The focus of study is Daman Formation belongs to upper oligocene age in Tapti-Daman block of Mumbai offshore basin. It is one of the established petroleum play. Daman formation consists dominantly of clastic sediments.

Estimating dry rock modulus

The relationship between pore aspect ratio and elastic moduli are:

\[ kd = \frac{km + 4\varphi n}{1 - 3A} \]
Porosity and clay content are important factors in the estimation of the elastic logs of the rock, but pore aspect ratio is also an important parameter which influences the elastic properties. The aspect ratio of sand grains and clay platelets is used to predict elastic logs which is then compared with model of Xu & White 1995. Xu & White divides the total pore space into two parts, one associated with sand grains and other associated with clay platelets. In this study, a model with fixed values of pore aspect ratio is set at 0.12 for sand related pores. The clay parameters for which the best match is obtained are as follows:

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Vp (m/s)</th>
<th>Vs (m/s)</th>
<th>Density (g/cc)</th>
<th>Aspect Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>5520</td>
<td>3600</td>
<td>2.65</td>
<td>0.12</td>
</tr>
<tr>
<td>Clay</td>
<td>2940</td>
<td>1400</td>
<td>2.55</td>
<td>0.045</td>
</tr>
</tbody>
</table>

Using these parameters, Rock physics modeling has done as shown in Figure 2.
Rock Physics Modelling with Multi-mineral Petrophysical model

The minerology impacts petrophysical calculations in numerous ways. The depositional environment and sediments being deposited will define the grain size, its sorting, and its distribution within the reservoir interval. In most sandstone reservoirs, the depositional environment controls the porosity/permeability relationship. The percentage of each and every mineral must be measured & their variation along the depth quantified. This is achieved through integration of prior geological knowledge, Core data, Conventional & high tech logging data.

Once the petrophysical parameters (Sw, Φ) and volumes (Vclay, Vsiderite, V pyrite, Vquartz) have been estimated through processing, they will be used in estimation of effective K (bulk modulus) & µ (shear modulus). These values will be used in Xu White model to calculate elastic logs as shown in Fig.3. In multi-mineral RPM model, the matrix (Quartz+ Siderite + Pyrite) bulk and shear moduli are estimated using Voigt-Reuss-Hill (VRH) approach. The VRH method uses the average from Voigt (upper) and Reuss (lower) to find the bulk modulus and shear modulus of mineral mixture.

Variable Aspect Ratio

The depth dependent aspect ratio as a function of porosity, clay volume, saturation and depth can better represent pore geometry and improve the model.

\[ a = f(Vcl, \phi, Sw, Vd) \]

(Given by Jason)

Variable Aspect ratio, α, calculated by multivariate regression method in Powerlog Jason software.

Using same clay parameters, Vp and Vs as shown in table 1, with variable aspect ratio, the 1D match (Fig.5a) and the Vp/Vs versus acoustic impedance crossplot (Fig.5b) are generated. The 1D match and crossplot with fixed aspect ratio are shown in Fig.4a & 4b.

Discussion

In Fig.2A, Petrophysical processing and Rock physics modelling with constant aspect ratio has been done with basic Quartz-Clay model showing the mismatch between recorded and model logs with poor correlation coefficient (Fig.2C, 2D). Also, the trend mismatch in Vp/Vs vs Acoustic impedance crossplot has been observed between the recorded and modeled data (Fig.2B) implying the change in the petrophysical volumes calculation.

Rock physics modeling incorporating multi-mineral processed volumes has been done showing the very good match between recorded & model logs (Fig. 3A, 3C, 3D). Also, the modeled data showing similar trend as the recorded one (Fig.3B) indicating the variation due to lithology has resolved.

In Fig. 4, Rock physics modeling has been done with fixed aspect ratio and in Fig.5, the same has been done with variable aspect ratio suggesting the best fit was observed with variable aspect ratio.

Conclusions

1. The elastic logs generated using variable aspect ratio show good correlation with the recorded data as compared to fixed aspect ratio.
2. Building of a Robust Petrophysical model using heavy minerals along with main Quartz-Clay matrix, gives more realistic and consistent elastic logs. There is difference in trend of recorded and model data with basic petrophysical model (Fig.2B) as compare to multi-mineral model (Fig.3B).
3. The elastic logs thus generated from the petrophysical interpretation into elastic domain, gives a better understanding of the seismic response in the entire area.
4. With these generated shear waves, Vp/Vs, AI have been crossplotted. Vp/Vs and AI crossplot is able to demarcate the shale, brine sands and hydrocarbon bearing sands. The elastic logs thus generated from rockphysics modelling can be used to identify and delineate geo-bodies in 3d space. This approach can give effective lead to seismic reservoir characterization guided by rockphysics modelling.
Acknowledgements

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Figure 1: Petrophysical Interpretation calibrated with NMR and ECS logs
Figure 2: RPM with basic Quartz-Clay model using fixed aspect ratio: (A) showing Log Data Processing results and 1D match of recorded (red) & model (black) density, DTCO, DTSM curves, (B) showing trends of recorded (red) and model (blue) in Vp/Vs versus P-impedance crossplots, (C) Correlation b/w recorded and model shear velocity (correlation 77%), (D) Correlation b/w recorded and model compressional velocity (correlation 80%), (E) Model Vp/Vs vs P-impedance crossplot with facies on Z-axis
**Figure 2:** RPM with basic Quartz-Clay model using fixed aspect ratio: (A) showing Log Data Processing results and 1D match of recorded (red) & model (black) density, DTCO, DTSM curves, (B) showing trends of recorded (red) and model (blue) in Vp/Vs versus P-impedance crossplots, (C) Correlation b/w recorded and model shear velocity (correlation 77%), (D) Correlation b/w recorded and model compressional velocity (correlation 80%), (E) Model Vp/Vs vs P-impedance crossplot with facies on Z-axis

**Figure 3:** RPM with Multi-mineral petrophysical model using depth varying aspect ratio: (A) showing Log Data Processing results and 1D match of recorded (red) & model (black) density, DTCO, DTSM curves, (B) showing trends of recorded (red) and model (blue) in Vp/Vs versus P-impedance crossplots, (C) Correlation b/w recorded and model compressional velocity (correlation 91%), (D) Correlation b/w recorded and model shear velocity (correlation 95%), (E) Model Vp/Vs vs P-impedance crossplot with facies on Z-axis
Fig. 3: RPM with Multi-mineral petrophysical model using depth varying aspect ratio: (A) showing Log Data Processing results and 1D match of recorded (red) & model (black) density, DTCO, DTSM curves, (B) showing trends of recorded (red) and model (blue) in Vp/Vs versus P-impedance crossplots, (C) Correlation b/w recorded and model compressional velocity (correlation 91%), (D) Correlation b/w recorded and model shear velocity (correlation 95%), (E) Model Vp/Vs vs P-impedance crossplot with facies on Z-axis.

**Figure 4a:** Comparison of compressional and shear logs with recorded data using fixed aspect

**Figure 4b:** Crossplot of Vp/Vs versus Acoustic Impedance using fixed aspect ratios.
Figure 5a: Comparison of compressional and shear logs with recorded data using variable aspect ratios.

Figure 5b: Crossplot of Vp/Vs versus Acoustic Impedance using variable aspect ratios.
Uranium Prospects Delineation Based on Well Logs and Core Data Analysis of Suket Jhalawar Area, Chambal Valley of Vindhyan Basin

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Abstract

This paper deals with study and prospect delineation for uranium integrating log, core and other geo-scientific data in Suket-Jhalawar area of Chambal Valley, Vindhyan basin. Well#X1 was the key well in the study area which was an exploratory well drilled for hydrocarbon exploration. 26 parametric wells were drilled for uranium exploration in the area.

Natural Gamma Ray, Spectral Gamma ray and Neutron logs have been recorded in these wells. Inductively Coupled Plasma Optical Emission Spectrometry (ICP-OES) study has been carried out in 15 core samples from 7 wells to confirm the uranium concentration. The maximum uranium concentration values from the core studies was up to 1279 ppm. It is observed that the uranium concentration obtained from the spectral log against the cored intervals is lower in value as compared to that obtained from the core studies.

The micro resistivity image log data has been processed and interpreted. The interpreted image log shows highly fractured sandstone/silt stone against the formation bearing high Uranium concentration which is further validated by core images of well PX#1 (10 m away from well no X#1).

The highest concentration peak observed in Well#X1 is named as Main peak. Another peak was observed above this and it was named as Universal peak as it appeared in all the wells of the study area. These two peaks are correlated in the wells to delineate the trend of uranium deposition. Uranium concentration is determined from spectral gamma ray spectrometry log in ppm. Beds are correlated first and uranium peaks are identified in wells thereafter. Correlation profiles based on log data are drawn in different directions to delineate the enrichment direction of uranium in the area.

Uranium concentration obtained from lab studies in general shows higher uranium concentration than log data. An attempt was made to find a relationship between the Uranium concentration of log and core data, but due to scarcity of core data points it was not possible to arrive at a conclusive relation between the two data sets.

As per our study, the future wells for uranium need to be drilled in north east direction in Suket area and south east direction in Mandawar area with respect to well #X1. The highly fractured sandstone seen in image log also suggests that In situ leaching (ISL) would be a viable option for extraction of Uranium from these sands.

Introduction

Suket Jhalawar area in Chambal Valley of Vindhyan basin is the study area (Fig. 1). The Chambal Valley Sector of Vindhyan Basin is located in Eastern Rajasthan, India and covers an area of approximately 80,000 km$^2$. It is the western continuation of Son-Valley, Vindhyan Basin albeit obscured by a 40,000 km drape of basalt towards the south. The albitite belt of Rajasthan with numerous uranium occurrences (Yadava et al., 2002) represents a potential belt for new discoveries.

The exploratory well X#1 was drilled by ONGC for hydrocarbon exploration in Suket Jhalawar area in 2013. Very high gamma ray activity along with high uranium concentration was observed at shallow depth of around X46 m within Nimbahera formation. This gave a lead to drill parametric wells for exploring uranium prospect at shallower depths.

The time structure map close to Nimbahera level reveals many Cross faults present in Suket block shown in Fig. 2. The most prominent fault named as Mukundra Fault, exhibits colossal up-throw and is perceived to have an increasing dip slip component towards southwest. It follows NW-SE trend and having surface manifestation starting from SE corner of the Suket Jhalawar area. It bifurcates in to two distinct areas i.e. NE side where both Vindhyan sequences (Lower and Upper) are present and SW side where only Lower Vindhyan sequence is present.
Methodology

Well X#1, the key well in study area was an exploratory well drilled for hydrocarbon exploration. 26 parametric wells have been drilled in this area. Available Log responses (Gamma ray, Neutron, Spectral gamma ray) were studied after performing initial data quality checks. Lithology correlation was carried out for all the wells available for the study. Then, equivalent uranium peaks were correlated in the wells to delineate the trend of the uranium enrichment direction. Profiles are interpreted with respect to well X#1. 15 core samples from 7 wells were studied at KDMIPE, ONGC Dehradun to analyze uranium concentration using Inductively Coupled Plasma- Optical Emission Spectroscopy (ICP-OES) method.

Wells X#1 and PX#1 were the key wells in the study area. Spectral Gamma ray log has been recorded in Well X#1 from 425m which indicates a high concentration uranium peak (232 ppm) at X46m, named as Main peak. Another high gamma ray activity was observed in the interval (Y86m-Y88m), named as Universal peak.
Based on gamma ray log response lithology have been demarcated into 4 segments from top to bottom as A, B, C and D respectively. This has been correlated with the core description lithology report available for the study. Bed-A is a shale bed (approx. 90% shale, as described in the core report). Top of Bed-B is the Nimbahera formation top. Universal peak is observed within this interval. Main peak is seen in Bed-C which is composed of quartzitic sandstone (sandstone=95%-90%, mica and pyrite present). Beds B and C are separated by a shale sequence (80% shale) of approx. 10 m thickness. Bed-D comprises of quartzitic sandstone (90-95% sand).

As we move from Well X#1 in NE and SE direction towards Jhalawar and Mandawar area respectively these beds are observed at shallower depth. In Mandawar area Beds A and B are absent.

Gamma ray and uranium (from spectral gamma ray) are used for bed correlation Fig. 3 and consecutively equivalent uranium peaks are correlated. Profiles are drawn in different directions to delineate the direction of uranium deposition in the area.

**Figure 3:** Lithology Correlation

Micro-resistivity Image data was processed for Well X#1. The processed image data shows (Fig. 4) several high angle fractures in the interval X44-X46 m.

**Figure 4 (a):** Core in the interval showing highly fractured

(b) Micro-resistivity processed image data showing high angle fractures
Core study shows the concentration of uranium is greater in core than logs. Reason behind this is the primary radioactive isotopes in rocks are potassium-40 and the isotope series associated with the disintegration of uranium and thorium. Potassium-40 ($^{40}$K) produces a single gamma ray of energy of 1.46 MeV as it transforms into stable calcium. On the other hand, both thorium (Th) and uranium (U) break down to form a sequence of radioactive daughter products. Subsequent breakdown of these unstable isotopes produces a variety of energy levels. Standard gamma ray tools measure a very broad band of energy including all the primary peaks as well as lower-energy daughter peaks.

In-situ leaching (ISL), also called in-situ recovery (ISR) or solution mining is a mining process used to recover minerals such as copper and uranium through boreholes drilled into a deposit, in situ. Uranium deposits which occur in permeable sand or sandstone confined above and below an impermeable strata and also are below the water table, are suitable for ISL. The design of ISL well fields varies depending on the local conditions such as permeability, sand thickness, deposit type, ore grade and distribution. The available concentration of uranium in our study area is suitable for extraction by in-situ leaching method.

**Conclusions**

Uranium concentration obtained from lab studies in general shows higher uranium concentration than log data. As per our study, the future wells for uranium need to be drilled in north east direction in Suket area and south east direction in Mandawar area with respect to well #X1. The highly fractured sandstone seen in image log also suggests that ISL would be a viable option for extraction of Uranium from these sands.

The micro resistivity image log indicates highly fractured sandstone/siltstone against the formation bearing high uranium concentration. This is also substantiated by the core samples of PX#1 (10m away from well X#1). An attempt was made to find a relationship between the Uranium concentration of log and core data, but due to scarcity of core data points it was not possible to arrive at a conclusive relation between the two data sets.

The available concentration levels of uranium in the study area appears suitable for extraction by in-situ leaching method.
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5. Mineralogical Characterization of Uranium Ore To Evaluate In-Situ Leaching Prospects, T.-F. Tsui, Mobil R&D Corp.


Characterisation and Petrophysical Evaluation of Fractured Granitic Basement Reservoir of Cauvery Basin, India

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Abstract

Petrophysical evaluation of fractured basements poses a major challenge due to hydrocarbons in place within an extensive fracture network rather than the conventional confining to matrix porosity. Hence, the focus is on the characterization of the fracture network as fractures provide both the storage and the conduit for the fluids. In this paper, a synergic methodology is adopted to integrate various wireline logs including openhole basic suite, advanced acoustics, elemental spectroscopy log, image log and NMR log for better evaluation of the reservoir potential in fractured, crystalline granitic basement with focus on fracture classification and fracture characterization (density, porosity & aperture estimation). Also, an attempt is made to validate the estimated potential zones contribution using production logs. A case study from Ariyalur-Pondicherry sub basin of Cauvery basin of Southern India is used to illustrate the robust workflow.

Introduction

The Cauvery Basin is a pericratonic rift basin, divided into a number of sub-parallel horsts and grabens, trending in a general NE-SW direction. Naturally fractured basement rocks of Precambrian are important reservoir targets in the Basin. The Precambrian basement rocks comprises of granites and gneisses.

Fracture Classification and Attitude from image log interpretation

Natural fractures are identified and classified from image log (FMI) into following four main types:

Vuggy Fractures These fractures have a wider aperture, irregular surfaces and vuggy porosities. In some cases, vugginess developed along the fracture surface (Fig-1a) and in other cases it is irregular (Fig-1b). Vuggy fractures are prevalent throughout the borehole here.

Continuous (non-vuggy) Fractures These are seen as sinusoid features in image log without any presence.
Discontinuous Fractures: These features are visible only on some part of the borehole image, but fail to form a continuous sinusoid (Fig-3).

Healed Fractures: These are continuous resistive (light coloured) features observed in the borehole image log. There is no associated stoneley energy loss with this kind of fractures (Fig-4).

The analyses of FMI logs indicate the natural fracture dip mostly towards NW direction (Fig-5). The drilling induced fracture is also seen in many places.

**Figure 3:** FMI static and dynamic images showing discontinuous fractures

![Discontinuous Fractures Image](image)

<table>
<thead>
<tr>
<th>Element</th>
<th>Ratio Approximation</th>
</tr>
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<tbody>
<tr>
<td>Si</td>
<td>0.25</td>
</tr>
<tr>
<td>Ca</td>
<td>0.25</td>
</tr>
<tr>
<td>Fe</td>
<td>0.25</td>
</tr>
<tr>
<td>Al</td>
<td>0.25</td>
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<tr>
<td>Ti</td>
<td>0.25</td>
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**Figure 4:** FMI dynamic image showing healed fracture & no indication in stoneley fracture analysis plot

![Healed Fractures Image](image)
**Elemental Concentration Cross-plots**

ECS tool measures dry weight percentages of silicon (Si), calcium (Ca), iron (Fe), titanium (Ti) and gadolinium (Gd). It evaluates aluminium (Al) percentage from anticorrelation algorithm. Relative ratios of these elements can reveal a lot about the heterogeneity in the granite. The elemental concentration ratios (Ca/Si, Fe/Si, Al/Si and Ti/Si) are plotted for entire basement section, only the top few meters of granite lie within green oval (zone A) and rest of the basement appears to be homogeneous, falling in purple oval (zone B) as shown in Fig-6.

**Figure 5:** FMI logs showing natural fracture dip mostly towards NW direction

**Figure 6:** Elemental concentration ratios (Ca/Si, Fe/Si, Al/Si and Ti/Si) plots
Fracture Characterization

Fracture characterization in granitic basement reservoirs plays a significant role to understand the potential of the reservoir. In the present well, vugs and fractures introduce secondary porosity and permeability. Here it is assumed, that the vugs are the consequence of hydrothermal alteration along pre-existing zones of weakness.

Porosity Estimation: Porosity estimation is a big challenge in fractured basement reservoirs. In case of granites, the “secondary” porosity corresponds to vugs and fracture features, whereas the apparent “primary” or “matrix” porosity appears to relate more to the effects of mineral alteration (Tandom T.M. et. al. 1999). The presence of fracture and vugs are well established from image logs and sonic data but existence of primary/matrix porosity can’t be confirmed in absence of any core data.

Porosity is estimated using density, sonic, resistivity, compressional and shear velocities, NMR and borehole electrical image. Density porosity is computed using continuous matrix density (RHGE) from Elemental Concentrations of spectroscopy measurements. Sonic porosity is derived from Wyllie’s time-average equation. The $\Delta t_{\text{matrix}}$ (zero porosity matrix slowness) is taken from a zone devoid of fracture and vugs. The resistivity based porosity is calculated using the Boyeldieu & Winchesters equation. Porosity from the compressional and shear velocities is estimated using Brie et al. acoustic scattering model. Borehole electrical Image log based porosity is computed using FracView and PoroSpect modules. FracView module computes porosity of conductive fractures visible on FMI log. Porosity Spectrum Analysis (PoroSpect) is a textural analysis technique that gives porosity distribution and vug fraction quantification from FMI.

Different logging tools provide different insights in calculating porosity. Each method investigates a different volume of the formation, hence it should not be surprising if the porosity estimates using different tools and techniques do not tally.

Porosities calculated from density, compressional and shear velocities, PoroSpect module and total NMR porosity are in close agreement with each other (Fig-7). All these porosities appear to be a combination of Vuggy, fractures and matrix (if applicable) porosities. The resistivity based porosity is lower than the other porosities in the studied well. The porosity estimated from FMI using Fracview Module is only for conductive fractures and it is less than 1% (Fig-7).

Figure 7: Porosities calculated from density, compressional and shear velocities, PoroSpect module and total NMR porosity are plotted on 6th track. Fracture aperture from electrical image and Laterolog resistivity, fracture density and porosity are plotted in 8th, 9th & 10th track respectively.
Sonic porosity is a measure of the primary or intergranular (matrix) porosity but in this study the sonic porosity is also found to be close to the above mentioned porosities. This may be due to the presence of in situ macroscopic fractures which lower P & S wave velocities and result in an increase in porosity. The quantitative estimation of the secondary porosity from the integration of acoustic and electrical well log data as proposed by Brie et al, is not applicable in the present study. This method was applied for determination of vuggy porosity, assuming the secondary-pore form as spheroid. This assumption makes this method improper for fractured formations.

Fracture Aperture and Density Estimation: Fracture aperture is estimated using electrical image log (Luthi 1990) and laterolog resistivity (Sibbit 1985). The fracture aperture estimation from Laterolog is lesser by one order of magnitude than from electrical image. This may be attributed to the difference in vertical resolution of the two measurements. Multiplying with a factor of 10 in the Laterolog based fracture aperture results in a closed match with the electrical image based fracture aperture. The Fracture density is computed using Fracview module. The Fracview outputs i.e. fracture aperture, porosity and density along with FMI dynamic image and fracture aperture from Laterolog resistivity are depicted in Fig - 7.

Advanced Acoustic Measurements

Sonic measurements are sensitive to fractures and can deliver additional inferences on evaluation.

Stoneley Fracture Analysis: Stoneley wave reflections and attenuation analysis has a unique advantage to recognize permeable fractures. As the Stoneley wave propagates pass through an open fracture, some of the energy is reflected, some is dissipated in the permeable fracture and the remaining part is transmitted. Stoneley wave reflections and attenuation analysis are known techniques for fracture evaluation.

Stoneley fracture analysis in the studied well provides the information of open fractures which is compared with FMI images to take decision for testing intervals (Fig-8).

Dipole Shear anisotropy Analysis: Fractures and stresses, important factors in production and development of reservoirs, influence the propagation of shear waves. This effect has been documented as anisotropy, where the shear waves split into two; fast- and slow-shear, with orthogonal particle-motion polarization directions. In fractured or horizontally stressed rocks the fast-shear waves are polarized along the direction of the fracture strike and/or maximum horizontal stress. The amount of anisotropy, e.g., the percentage difference in slownesses, varies with fracture frequency or the amount of unbalanced subsurface stress.
Shear-wave splitting along with fast shear-azimuth direction is useful for evaluating fracture zones and the same is observed in FMI Image (Fig-9).

**Radial Profiles of Slowness Variation:** The P&S radial profiling of slowness provide information on formation damage. In the studied well, formation damages are observed and they are mostly against highly fractured zones (Fig-10).

**Validation with Production Logging (PL)**

Production logging tools are run in the well to ascertain the nature and behaviour of fluids in the borehole and to test the individual fracture zones dynamically for comparison with static log measurements (Fig-11).

![Figure 10: Plot of Dipole Radial Profiling](image1)

![Figure 11: Production Logs](image2)

PL measurements in flowing condition validate the fracture zones defined by the logs contributing to flow. PL results here indicate that the maximum contribution is from upper few meters only. As the well was drilled with heavy mud weight, insignificant contribution from lower part is either due to formation damage as observed in P&S radial profiling or accumulation of unrecovered heavy drilling fluids in wellbore or combination of both.

**Conclusions**

- The integrated approach presented here uses the potency of each and tries to compensate for the limitations of every measurement available.
- This approach delivers four critical elements for fracture analysis and evaluation; (a) fracture class & density, (b) orientation & dips magnitude, (c) fracture aperture and (d) fracture porosity.
- Production logs play a significant role in authenticating the individual fracture zones dynamically for comparison with static log measurements.
- This approach accentuates the importance of integrating different datasets for detailed reservoir characterization leading to increase confidence in effective evaluation and management of complex basement reservoir driving the point that a single measurement is not sufficient for fracture evaluation in heterogeneous granitic rocks.
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**Nomenclature**

<table>
<thead>
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<th>Abbreviation</th>
<th>Description</th>
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<tr>
<td>NMR</td>
<td>Nuclear Magnetic Resonance</td>
</tr>
<tr>
<td>FMI</td>
<td>Fullbore Formation Microimager - a Schlumberger tool</td>
</tr>
<tr>
<td>ECS</td>
<td>Fullbore Formation Microimager - a Schlumberger tool</td>
</tr>
<tr>
<td>RHGE</td>
<td>Matrix Density from Elements - data channel of ECS tool</td>
</tr>
<tr>
<td>FracView</td>
<td>a Schlumberger interpretative software</td>
</tr>
<tr>
<td>PoroSpect</td>
<td>a Schlumberger interpretative software</td>
</tr>
<tr>
<td>P &amp; S</td>
<td>Compressional (or P-waves) and shear (or S-waves)</td>
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**Acknowledgement**
The authors express their deep sense of gratitude to the Management of Directorate General of Hydrocarbons for permitting to publish this paper.

**References**


Determination of Degree of Cleating/ Fracturing by Using Vp/Vs and Poisson's Ratio (PR) to Identify Prospective Coal Seams: A Case Study from Jharia CBM Block, India

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Abstract

VpVs ratio (Vp=sonic compressional velocity and Vs= sonic shear velocity) and Poisson's ratio (PR) are widely used as gas indicator in conventional hydrocarbon reservoir. Sonic shear slowness is sensitive to gas as well as fractures of the reservoir. CBM production depends critically three parameter of coal- gas content, saturation and permeability of coal. Cleats and fractures existing in coal are responsible for its permeability. Presence of cleats/fractures in coal increases the shear slowness and tends to reduce the modulus of rigidity of formation. Thus ratio of compressional slowness (Vp) and shear slowness (Vs) and Poisson's ratio(PR) can be good indicators of cleat/fracture in coal as both are influenced by cleat/fracture. High VpVs ratio and high PR values are expected in coals with high degree of cleating.

In the present study, cross plots of VpVs ratio with compressional slowness (DTCO) and cross plots of Poisson's ratio(PR) with bulk density have been studied against different coal seams of a well from Jharia Block using Dipole Sonic Imager(DSI) log data to compare degree of cleating/fracturing density of each coal seam. The study would help to identify the prospective coal seams of the well for finalization of completion strategy.

Introduction

In recent time, exploration of Coalbed Methane (CBM) gas has got momentum to meet the energy need of our country. Through R&D and exploratory work, CBM has been projected as a viable major energy source of future. Exploration of CBM is different from conventional hydrocarbon. Coal acts as both source and reservoir rock. Methane in coal occurs in adsorbed state on the surfaces of the coal and remains dissolved in water within cleats and fractures. Coal is low permeable rock. The cleats/fractures in coal create path ways for methane gas to flow. Hydro-fracturing job enhance the permeability of coal reservoir. Traditionally, open hole logs (Gamma ray, Neutron, Density, Resistivity and Sonic) are used to identify and delineate coal seams in CBM reservoir. Information of fracture network in coal is difficult to get from conventional log data. High tech image logs such as Sonic scanner and FMI are suitable for fracture characterisation but the services are very costly and can not be used frequently.

Sonic shear slowness is affected by fractures. Shear slowness increases in presence of fractures and hence VpVs ratio tends to increase in the coal seam. Similarly, Poisson's ratio in fractured coal will increase as modulus of rigidity decreases with increase of shear slowness.

Keeping in mind the above relation, an attempt has been made in the present study to evaluate degree of cleating through cross plots of VpVs - DTCO and PR - Density against each coal seam of Well JH -X. Study of VpVs and PR values will help to identify the prospective coal seams for production planning.
Gas production in CBM well is very low as compared to conventional Oil&Gas production in a well. Moreover, gas price is in downward trend in international market. Use of high tech logging is costly affair. To make the CBM production cost effective, operational cost needs to be minimized. Right selection of pay zones plays a significant role in optimization of production and operating cost. VpVs and PR technique to identify potential coal seams using DSI log data would be more cost effective as Logging services is going to include DSI logging among basic log suites in ongoing wire line contract.

**Geological background**

The Jharia coalfield, covering an area of about 450 sq.km is one of the major coalfields of Damodar Valley coal belt and is second member from the east. It is an outlier of Permo-Carboniferous Gondwana sediments in an Archaean country. The Jharia coalfield is roughly sickle shaped synclinal basin with an east-west alignment. The southern boundary of the basin is prominently marked by a major WNW-ESE trending fault, commonly known as “Great Boundary Fault”. Barakar is the main producing formation covering an area of 218 sq.km with max. thickness 1250mts. Barakars contain 18 major workable coal seams which are mostly cooking coals.

**Relevance of cleats/fractures in CBM**

Cleats are natural fractures that form in coal seams as a result of coal dehydration, local and regional stresses and unloading of overburden. Cleats usually occur in two sets, face and butt which are mutually perpendicular to each other and also to the bedding plane. The significance of cleat has been widely recognized as having a control on occurrence, migration & production of coalbed methane. The dominant flow direction is related to the existing cleat system and is controlled by the Darcy permeability. Permeability of coal primarily depends on the presence of the cleats/fractures. Two critical coal properties related to coal permeability are fracture intensity and stress relationships. Natural fractures are the primary flow path within the coal reservoir. The amount of cleating in coal is generally related to coal rank, vitrinite content, mineral content, and tectonic activity of the reservoir. The cleat properties also govern the exploration and development of a CBM reservoir due to their influence on recovery of methane and the local and regional flow of hydrocarbons and water.

![Figure 1: Composite Logs of Well JH-X showing coal seams](image)
**Case study**

Well JH-X of Jharia coal block in Parbatpur area was drilled down to 1185 mts as exploratory well to explore the methane potential. Conventional open hole logs (Gamma ray, Resistivity, Neutron, Density) as well as high-tech logs DSI and FMI were recorded for detailed analysis of coal seams. Total thirteen coal seams (Fig-1) were encountered out of which, nine (A to I) seams were identified for study based on log motifs (GR 37-57 API, Resistivity 2000-3000 ohm-m, Neutron porosity 50-60 % and Density 1.33-1.41 gm/cc) belonging to Barakar Formation. Cross plots of VpVs ratio with compressional slowness (DTCO) and Possion’s ratio (PR) with density were generated against each coal seam and analysed. Detailed results are given in Table-1. Results show that VpVs ratio and PR values of coal varies between 1.78 to 2.7 and 0.26 to 0.42 respectively in Barakar Formation. VpVs ratio for coal lithology is 1.9-2.3 and for shale 1.7-2.1 as given in Crain’s Petrophysical Handbook (Table-2). Compared to that, VpVs values below 1.9 indicates the Ash (shale) content in the coal and coals having VpVs more than 2.3 may have developed more cleat/fracture network. VpVs versus DTCO for all nine coal seams have been presented together in cross plots Fig-4(a) and 4(b) for comparative study.

The study shows that, coal seams B to H are having VpVs values more than 2.3 and coal seams A & I are having 2.1 & 2.2 respectively. PR values of seams B to H are also higher (>0.35) compared to A & I seams. High VpVs value signifies presence of high degree of cleats/fractures in the coal seams. Therefore, seven coal seams B to H have developed cleat/fracture of different degree and are having higher prospect of gas production as compared to A & I. We can categorise the seams further such as B is having high degree of cleating, C, D & F good, E & H moderate and G, A & I are having low cleating. Similar inference can be drawn from PR Vs density cross plot comparing PR values of coal seams with respect to normal PR of coal.

<table>
<thead>
<tr>
<th>Coal Seam</th>
<th>Interval (m)</th>
<th>VpVs range</th>
<th>PR range</th>
<th>Cleat/Frac density from FMI( per m)</th>
<th>FMI analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>890.3-592</td>
<td>1.78-2.1</td>
<td>0.26-0.36</td>
<td>2</td>
<td>Partially developed banding and three conductive fractures. No cleat observed.</td>
</tr>
<tr>
<td>B</td>
<td>836.7-839.6</td>
<td>2.3-2.7</td>
<td>0.29-0.37</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>881-883.4</td>
<td>2.2-2.5</td>
<td>0.36-0.41</td>
<td>3</td>
<td>Conductive fractures observed</td>
</tr>
<tr>
<td>D</td>
<td>770.8-777</td>
<td>2.0-2.57</td>
<td>0.32-0.42</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>E</td>
<td>708-713</td>
<td>2.0-2.42</td>
<td>0.33-0.40</td>
<td>4</td>
<td>Partial bending, one set of cleat system and a set of conductive fractures are present.</td>
</tr>
<tr>
<td>F</td>
<td>682.2-693.4</td>
<td>2.0-2.58</td>
<td>0.33-0.42</td>
<td>8</td>
<td>Both cleat system and conductive fractures are present.</td>
</tr>
<tr>
<td>G</td>
<td>649.8-652.8</td>
<td>2.18-2.35</td>
<td>0.36-0.40</td>
<td>4</td>
<td>Both cleat system and conductive fractures are present.</td>
</tr>
<tr>
<td>H</td>
<td>640-648.2</td>
<td>2.03-2.45</td>
<td>0.34-0.40</td>
<td>5</td>
<td>Prominent banding and a well developed cross cutting cleat system is observed.</td>
</tr>
<tr>
<td>I</td>
<td>603-605.3</td>
<td>2.14-2.2</td>
<td>0.34-0.38</td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>

**Table 1:** VpVs and PR values against each coal seam
Case study

Well JH-X of Jharia coal block in Parbatpur area was drilled down to 1185 mts as exploratory well to explore the methane potential. Conventional open hole logs (Gamma ray, Resistivity, Neutron, Density) as well as high-tech logs DSI and FMI were recorded for detailed analysis of coal seams. Total thirteen coal seams (Fig-1) were encountered out of which, nine (A to I) seams were identified for study based on log motifs (GR 37-57 API, Resistivity 2000 -3000 ohm-m, Neutron porosity 50-60 % and Density 1.33-1.41 gm/cc) belonging to Barakar Formation. Cross plots of VpVs ratio with compressional slowness (DTCO) and Possion’s ratio (PR) with density were generated against each coal seam and analyzed. Detailed results are given in Table-1. Results show that VpVs ratio and PR values of coal vary between 1.78 to 2.7 and 0.26 to 0.42 respectively in Barakar Formation. VPVs ratio for coal lithology is 1.9-2.3 and for shale 1.7-2.1 as given in Crain’s Petrophysical Handbook (Table-2). Compared to that, VPVs values below 1.9 indicates the Ash (shale) content in the coal and coals having VpVs more than 2.3 may have developed more cleat/fracture network. VpVs versus DTCO for all nine coal seams have been presented together in cross plots Fig-4(a) and 4(b) for comparative study. The study shows that, coal seams B to H are having VpVs values more than 2.3 and coal seams A & I are having 2.1 & 2.2 respectively. PR values of seams B to H are also higher (>0.35) compared to A & I seams. High VpVs value signifies presence of high degree of cleats/fractures in the coal seams. Therefore, seven coal seams B to H have developed cleat/fracture of different degree and are having higher prospect of gas production as compared to A & I. We can categorise the seams further such as B is having high degree of cleating, C,D&F good, E &H moderate and G,A&I are having low cleating. Similar inference can be drawn from PR Vs density cross plot comparing PR values of coal seams with respect to normal PR of coal.

<table>
<thead>
<tr>
<th>Lithology</th>
<th>VpVs ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1.9 to 2.3</td>
</tr>
<tr>
<td>Shale</td>
<td>1.7 to 2.1</td>
</tr>
<tr>
<td>Limestone</td>
<td>1.8 to 1.9</td>
</tr>
<tr>
<td>Dolomite</td>
<td>1.7 to 1.8</td>
</tr>
<tr>
<td>Sandstone</td>
<td>1.6 to 1.7</td>
</tr>
</tbody>
</table>

Table 2: Values of VpVs ratio for different lithology

Validation of study result

Study results were verified with the available proximate analysis data and high resolution resistivity image log Cleat characterization of well JH-X was done by M/s Schlumberger by using Formation Micro Imaging (FMI) log and DSI. It was found that FMI analysis by Schlumberger is in good agreement with the study results. Processed dynamic image of FMI and cross plots against coal seam A and H have been presented in Fig-2 and Fig-3 respectively for example. As per FMI, partially developed banding and three conductive fractures were observed but no cleats in coal seam A. But in coal seam H, prominent banding and a well developed cross cutting cleat system was observed with cleat density 5/m. Therefore, FMI analysis shows that degree of cleating in seam H is high with and in coal seam A is low ie coal seam H is more prospective and coal seam A is less prospective. The results are verified by VPVS ratio and PR values from cross plots. VPVs & PR values are high (2.45 and 0.40 ) in coal seam H and less than normal coal value (2.1 and 0.35) in coal seam A which confirms coal seam H is more prospective than seam A. Moreover, cleat/fracture density observed through high resolution resistivity image (FMI) are corroborating with max. values of VpVs ratio and PR values.

These seven coal seams (B to H) were put under commingled production during testing and they produced gas which further validates our study result.

VpVs ratio and Cleat/Fracture density relation

As VpVs ratio varies with Cleat/Fracture density of coal seam, to establish their relation a transform between VpVs ratio and cleat/fracture density derived from FMI image log was generated(Fig-5). The relation between these two parameters is expressed by \( Y = 7.420X - 13.56; R^2 = 0.919 \) where \( Y = \) VpVs ratio and \( X = \) cleat/fracture density per meter and R is fitness co-efficient which that there is very good relation between two parameters. This transform can be used to estimate cleat/fracture density of coal seams from it’s Vp/Vs values.

These seven coal seams (B to H) were put under commingled production during testing and they produced gas which further validates our study result.
Conclusions

Vp/Vs-DTCO and PR-Density cross plots are good indicators of cleat/fracture density and may be used to identify prospective coal seams in combination with conventional log suites. Coal seams with high Vp/Vs ratio may be recommended for perforation as connectivity would be very good in such seams in comparison to coal seams with lower Vp/Vs ratio. The transform generated between Vp/Vs ratio and Cleat/fracture may be used to find out cleat density of coal seams using Vp/Vs ratio where DSI log is available.

Acknowledgement

The authors are indebted to GGM-Asset Manager, CBM Asset, Bokaro for his encouragement and support. Authors are thankful to the executives of Geology, Reservoir for providing required data and technical inputs. Thanks are due to the colleagues of Logging group for their help and cooperation for the study. Views expressed in this paper are those of authors only and may not necessarily be of ONGC

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Figure 1 (Coal-A): Low degree cleating; VpVs ratio: 1.78-2.1; PR: 0.26-0.36

Figure 3 (Coal-H): High degree cleating; VpVs ratio: 2.03-2.45; PR: 0.34-0.40

Figure 4(a) & (b): Seam wise comparative study of Cleating/Fracturing
Evaluation of Mineralogical Composition for Reliable Petrophysical Model by Advanced Neutron Induced Gamma Ray Spectroscopy in Heavy Oil Sands, Cambay Basin: A Case Study

Gaurav Kumar Sharma, ONGC Ltd., Mehsana, Ramesh Chander Pareek, ONGC Ltd., Mehsana, G. Satya Swaroop, ONGC Ltd., Mehsana, R. L. Singh, ONGC Ltd., Mehsana, Ajay Kumar, HLS Asia Ltd., India, Ravinder Kumar, HLS Asia Ltd., India, R. N. Chakravorty, HLS Asia Ltd., India

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Abstract

The big challenge during petrophysical analysis of any rock is to build reliable petro physical model incorporating sufficient information of the mineralogy that constitutes the formation. Cross-plots based on traditional logs do not help for mineral identification particularly when the mineralogy is complex and different minerals have similar overlapping physical properties. To overcome this problem, the neutron induced gamma ray spectroscopy measurements have been a precious input for decades. The practice continues even now, but with additional ability to measure aluminum (Al), manganese (Mn), and magnesium (Mg) elemental weight percentages besides conventional elements the industry witnesses. The advancement in technology with improved and wider measurement capabilities is leading to precise mineralogical evaluation, not previously achieved. The petrophysical models are more reliable using this mineralogical composition as input providing results closer to reality which is otherwise difficult.

The study pertains to well drilled in Santhal field, southern segment of “heavy oil belt” of North Cambay basin, India. The varying mineralogy characteristically makes the petrophysical evaluation difficult by using basic conventional log suites. To validate and further improve existing petrophysical model, in Upper Suraj and Kalol pay sands, advanced neutron induced capture spectroscopy data was acquired along with conventional logging suite. The pay sands are separated from each other by shale of varying thickness. The measured spectroscopy data comprises dry weight percentages of Si, Ca, Fe, S, Ti, Mg, Gd, Al, K, and Mn. The data was analysed using various elemental cross-plots and information from cores available in offset wells. The measured spectroscopy data was used as input to multi-mineral solver software, providing mineralogy output, consequently yielding better porosity and water saturation calculation.

The results shows, Fe occurs in high concentration in Upper Suraj Pay (USP). The ratio of Fe and Al is abnormally high more nearly typical of hydrated iron oxide. The mineralogical evaluation suggests that this pay is clayey with minerals comprising quartz, siderite, and limonite. The concentration of iron and aluminum is relatively very low in Kalol pay sands (KS-I, II, III & LS). KS-I is clean whereas KS-II is argillaceous. The intermittent shales are characterized by a low K as well as high Al and Fe. The shales are seen enriched with Ti. The mineralogical analysis suggests the composition of the shales, predominated by main clay minerals as kaolinite and chlorite in addition to variable ratio of montmorillonite, while the non-clay minerals include quartz, calcite and siderite. The presence of S is seen nearly typical of pyrite in shale section overlying Kalol formation.

This paper describes the application of advanced neutron induced capture spectroscopy data to petrophysical evaluation and characterization of Upper Suraj pay, Kalol pay sand and intermittent shale section. The results in the studied well are in agreement with core data of offset wells. There is enhancement in interpretation abilities in the formation for accurate porosity and water saturation computations, and finally accomplishing better understanding of reservoir.

Introduction

Santhal field is part of the heavy oil fields of Mehsana block in Cambay basin. The field was discovered in 1970 and put on production in 1974. This field, along with Balol and Lanwa fields, is part of a single structure spread over along south to north, Figure 1. It is monocline and west-east dipping, abutting at Mehsana Horst in the west and supported with active edge-water from east. The field is spread over an area 6 km long and 3 km wide. The Kalol formation of Eocene age is the main hydrocarbon bearing formation. Which is subdivided into Upper Suraj Pay, KS-I, KS-II, KS-III and LS. The pay sands are separated from each other by shale of varying thickness.
The Kalol sands are found at a depth of about 850 to 1000 m having heavy oil of 17º API. Upper Suraj Pay and Kalol sands represent significant variety in reservoir characteristics (i.e. mineralogy, porosity, and permeability). In general, USP is tight in nature while other reservoirs are porous. USP comprises of quartz wacke with siderite and its alteration products like limonite. Kalol sands (KS-I, II, III & LS) are loose unconsolidated sandstones separated by shale layers of various thickness. All the sands are hydro dynamically interconnected. This warrants a need to apply suitable technology for quantitative estimate of formation mineralogical composition providing:

- Improved accuracy and assurance for evaluations in simple mineralogy formation
- Improved volumetric petrophysical evaluations in complex mineralogy formation

This paper describes the demonstrated solution using advanced neutron induced gamma ray spectroscopy for these needs.

**Approach**

An accurate predictor of clay content is Al. The old geochemical tool were not able to precisely measure this element and only solution was to use the empirical relationships that provide an Al emulation based on the quantity of Si, Ca, and Fe. Nevertheless, now there is improvement in technology that directly measures some of the key, yet difficult elements to quantify:

- Aluminum for shales / clays
- Magnesium for carbonates (Dolomite vs. Limestone)
- Manganese for a common constituent of carbonates and sheet silicates.

This advancement in technology with improved and wider measurement capabilities has led to precise mineralogical evaluation and grain density. The petrophysical models are more reliable using this mineralogical composition as input providing results closer to reality which is otherwise difficult.

The measured neutron-induced gamma ray spectra is processed using a weighted least-squares solver to extract relative elemental yields. Then, the relative yields are converted into dry-rock elemental weight fractions by running an oxides closure model.

**Figure 1: Heavy Oil Fields of Cambay Basin**
**Oxides closure model**

The relative elemental yields are reflective of elemental concentrations in the formation, but they are not directly useful for petrophysical evaluation. To be used in a meaningful way, the relative yields must be converted into absolute elemental weight fractions. The relative yields can be converted to elemental concentrations by dividing each yield by a relative sensitivity factor as gamma rays produced in the formation are proportional to the neutron flux in the formation. The neutron flux in the formation depends on several environmental parameters, and therefore can vary from depth to depth in a given well, though neutron output from the americium-beryllium source is constant. The problem is overcome by accounting for variability of the neutron flux by applying a depth-varying normalization factor. In the industry, main technique used to derive the necessary depth-varying factor is the oxides closure model (Hertzog, et al., 1987), which assumes the primary formation elements measured by the tool sum to unity and exist as a single oxide or carbonate., i.e.,

\[
F \left[ \sum_i O_i \frac{y_i}{S_i} \right] = 1
\]  

where
\[
F = \text{the depth-varying normalization factor},
\]
\[
O_i = \text{ratio of the oxide or carbonate associated with element } i \text{ to the weight of element } i,
\]
\[
y_i = \text{relative yield for element } i, \text{ and}
\]
\[
S_i = \text{relative sensitivity factor for element } i
\]

Elemental weight fractions for each element, \( W_i \), are computed according to the relationship

\[
W_i = F \frac{y_i}{S_i}
\]

After that, bulk density and neutron-density cross-plot porosity inputs are used to calculate the equivalent wet-rock elemental weight fractions. This data along with various types of log inputs, including: conventional density, neutron porosity, resistivity, natural and spectral gamma ray, is now used in fluids and minerals evaluation model that uses a probabilistic error minimization methodology to derive formation fluid and mineral volumes.

In this case, the mineralogy model consists of kaolinite, chlorite, quartz, calcite, siderite, limonite and pyrite based upon local geology and core data. No dolomite of any significance occurs in any of the XRD mineralogy data; consequently, it is excluded from the log interpretation model.

**Fluids and Minerals Analysis (FAME)**

The *FAME* module is an advanced integrated answer product that uses a probabilistic error minimization methodology to derive formation fluid and mineral volumes from various types of log inputs, including: conventional density, neutron porosity, acoustic, resistivity, natural and spectral gamma ray, formation capture cross-section, and elemental geochemical. Performing the calculations in this technique requires theoretical log response equations for each sensor used. Response equations have been constructed in terms of formation mineral and fluid volumes and the response parameters for each constituent. Linear mixing laws were followed for most sensors but some, such as neutron, resistivity, acoustic, and dielectric involved more complicated non-linear functions. The idea is to solve the system of simultaneous theoretical tool response equations for the mineral and fluid volumes that gave the best match to the logs. Analyst construct a log analysis model consisting of response equations, parameters and constraints. Analyst also control the weight of each tool in determining the solution and define appropriate linear inequality constraints to restrict the solution space for the selected formation volumes.
Central to the FAME model is a volumetric representation of the reservoir constituents as illustrated in Figure 2. The model supports independent volumes of free (non-clay-bound) water, gas, and oil in the invaded and undisturbed zones, a total volume of clay-bound water, and mineral volumes. Mineral volumes in this context refer to individual dry mineral volumes for clay minerals less their respective clay-bound water volumes, which are included in the total clay-bound water volume. Thus mineral volumes (VMIN) represent generic solid material; clay minerals and other sheet-silicate minerals are designated by a non-zero wet clay porosity (WCLP) response parameter corresponding to the fractional volume of clay-bound water associated with the wet clay. Thus, the total clay-bound water volume (VCBW) among the modeled minerals is given by

\[
\text{Clay Bound Water} = \sum_i \frac{WCLP_i}{1-WCLP_i} VMIN_i 
\]

And the total volume of wet clay is the sum of VCBW and the sum of mineral volumes whose WCLP response parameters are greater than zero. It follows then, VCBW is an implicit formation volume when minerals with non-zero WCLP response parameters are solved for. Effective porosity, \( \phi_e \), is defined as the sum of free water, gas, and oil volumes. Total porosity, \( \phi_t \), is the sum of \( \phi_e \) and VCBW.

### Field Example

Santhal Well – Figure 3 shows logs obtained in the brine-filled borehole with a clastic interval near the top of the Kalol Pay (KS-I). In addition to the caliper, Track-I includes gamma-ray equivalent of the radioactivity from thorium and potassium. The resistivity log are shown in Tracks-II. Formation density and neutron porosity logs are displayed in Tracks-III. Dry rock elemental weight fractions are shown in Track-IV, as described previously.

The logged interval spans a sand-shale sequence that includes Upper Suraj pay and Kalol pay sands. Various elemental cross-plots (Figure 4 and 5) were made to infer the mineralogy results. Elemental results for this example exhibit anti-correlation of iron & silicon and iron and aluminum against limonite dominated formation overlying Kalol pays. The results shows layer KS-I as clean and KS-II as argillaceous, whereas, USP is clayey with minerals comprising quartz, siderite, and limonite. The main clay minerals in shale section are kaolinite and chlorite. The presence of pyrite and calcite is noticed in the formation overlying Kalol formation.
Figure 3: GEM elemental weight fractions (dry) from the well from Santhal field.
Figure 3: GEM elemental weight fractions (dry) from the well from Santhal field.

Figure 4: The aluminum-silicon cross-plots against shale (left) and Kalol pay sands KS-I & II (right).

Figure 5: The Iron-silicon cross-plot against limonite (left) and aluminum-silicon cross-plot against USP (right).

Figure 6 and 7 shows the petrophysical evaluation using the FAME formation volume model. Wet rock volume fractions are displayed in Track-V. Effective water saturation is shown in Track-VI. The clean KS-I sand is characterized by grain density of the order of 2.65 gm/cc whereas argillaceous sand KS-II has grain density in the range of 2.60-2.62 gm/cc. It is to be noticed that flu gas is present in Layer KS-I as a result of in-situ combustion. Layer KS-II possess the oil, yet to be produced. Figure-7 shows the mineralogical composition in shale section.
Conclusions

The neutron induced gamma ray spectroscopy data has been demonstrated to be an effective means of establishing the mineral model for petrophysical evaluation. Encouraging results have been obtained from elemental cross-plots. Of particular interest are the results for high Fe/Al & Fe/Si ratio obtained in the limonite rich clastic. Also noteworthy are high Fe responses observed against the shale section. The mineralogical analysis suggests the composition of the shales, predominated by main clay minerals as kaolinite and chlorite in addition to variable ratio of montmorillonite, while the non-clay minerals include quartz, calcite and siderite. The presence of calcite and pyrite is seen in the formation overlying Kalol formation. Fe also occur in high concentration in USP and mineralogical evaluation suggests that this pay is clayey with minerals comprising quartz, siderite, and limonite. The concentration of iron and aluminum is relatively very low in Kalol pays. These sands are described as clean/argillaceous. The results in the studied well are found to be in agreement with core data of offset wells.

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The authors would like to thank ONGC Ltd. for the release of the geochemical log data, and core analyses data used in this study and for supporting the publication of this paper. In addition, the open discussions with ONGC Ltd. and their suggestions are deeply appreciated. We also thank management of HLS Asia for the facilities to undertake this work.

Reference


Figure 6: Fluid and minerals analysis using GEM elemental weight fractions and conventional log data from the well from Santhal field.
Conclusions

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Reference


Integrated Field Study of Paliyad Field
(K-VIII Pay Sand & K-IX Pay Sand)

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Abstracts

The Wadu-Paliyad field is located contiguously towards north of Kalol field in Ahmedabad-Mehsana block of Cambay basin was discovered in 1983 and put on production in 1989. In Paliyad field, the K-VIII pay is the main contributor for oil. The objective of the study is “An overview of Paliyad field (K-VIII and K-IX Pay sand) field through wire line log data for hydrocarbon prospect”. The study was carried out with available conventional log data; which were processed using ELAN plus module to get petro physical parameters (viz. Vcl, PHIE, Sw, Net Pay thickness & hydrocarbon porosity thickness) of 38 wells of Paliyad field; using Multi mineral model. The well log motif, correlation, testing results and Geological inputs of Paliyad field has taken into account during processing. This study will be beneficial for Ahmedabad Asset in general and SST in particular for effective reservoir characterization & finding new prospective location in near future of K-VIII and K-IX pay Sand.

Methodology adopted

The field was divided into three sectors for correlation purpose. Three sets of well log correlation(Fig:1a, 1b, 1c) have been carried out in wellpix / cross section module of GeoFrame to see the comparative log characteristics for better understanding of facie variation, lateral continuity of pay sands & structural variance from well to well.

Cross plots show the presence of some heavy minerals which is also confirmed by core/cutting reports of some wells. Cross plots (potassium vs thorium) also indicate dominance of kaolinite and chlorite as minor clay minerals. Various cross-plots viz. Picket plot, Rwa-GR plot were used to identify the formation water resistivity; The RHOB-NPHI plots were used to identify the lithology. Buckle’s plot used to find out the quality of the reservoir and whether there will be water free production or not consequent upon initial production. The study has been carried out with the available conventional log data of old wells. In some of the wells, the data quality is affected due to caving/wash out. However realistic petrophysical parameters (Vcl, PHIE, Sw, Net pay thickness & HC porosity thickness map etc.) were computed using ELAN plus, Ressum module. And the Geology base map module of Geoframe software has been used for gridding and contouring of petrophysical parameters. Correlation of the wells are carried out through cross section module of Geoframe. The computed parameters were plotted on contour map to understand the variation of petrophysical parameters / facies and to identify the prospective location /areas in the field.

The evaluated petro-physical parameters (Vcl, PHIE, Sw, Net Pay thickness & hydrocarbon porosity thickness) of 38 wells of Paliyad field were used to make in different contour maps. The techniques are substantiating with the testing results of presently studied wells and the wells drilled after the Study. Two wells drilled after the study are agreeing 95%, what was expected from study. However results may not match in those sands which are not encountered or outside of the study area. This study has been carried out for both K-VIII and K-IX Pay sands. During the study the geological wire-line data (FMI, XRF & STAR data) has taken into account and interpreted the paleo current direction and sand thickening direction which was validated thru true stratigraphic thickness map.

Conclusion / Recommendation

On the basis of evaluated petro-physical parameters, log correlation motif, testing results and Geological inputs the interpretation made against K-VIII and K-IX pay sand have summarised below and prospective areas from hydrocarbon point of view have been identified in K-VIII & K-IX Pay Sands.
K-VIII Pay Sand

- The correlation was made in three sectors, northern, central and southern sectors (Fig:1a, 1b,1c) for visualisation purpose. In Northern part correlation, wells towards eastern side are structurally up as compare to wells of western part. In case of central part correlation, the wells of western and eastern parts are structurally not much variation except the wells which are presents at extreme east found structurally down as compare to other wells. In the southern part correlation, the wells of western and eastern parts are structurally not much variation except the wells which are presents at extreme east found to be structurally up / pay sand not developed as compare to other wells. The K-VIII pay sand is very well developed in central-eastern part of Paliyad field. It is structurally down in the extreme eastern part of the field.
- The average clay fraction(Fig:2) of the field is varying between 20-55%, whereas the wells towards eastern part are having less clay volume as compare to the well present at western part. The Av.Vclay towards central-eastern side is approx.35%. Whereas towards western side (in Vicinity of the well L#35) is around 55%.
- The effective porosity (fig:3) of the field is varying in between 15-25pu. The average effective porosity in central-eastern part is around 22pu, whereas average effective porosity of K-VIII pay sand in this field is around 20pu.
- The variation of average water saturation (fig:4) of this field is in between 30-50% in the wells where the pay sand is hydrocarbon bearing. The average water saturation of the field is around 45% (exclusion of wells where K-VIII pay is water saturated). Wells which are presented in NE-E part and S-SW part of the fields are water bearing.
- The average net pay thickness (fig:5) of the field is in between 7.5-24.0m. The average net pay thickness in central-eastern part is around 22m whereas average net pay thickness of K-VIII pay in this field is around 12m.
- The Net pay Hydrocarbon porosity thickness (Fig:6) at central part is in between 1.75-2.77m.
- In this field, in eight wells image log have been recorded. Image has processed, generated static, dynamic images & dip (Fig:7) has been computed. From image log K-VIII pay sand appears to be fine lamination of sand & shale. Dips are within 10 deg and azimuth direction are NW-SW. In some of the wells feeble blue pattern have been observed in K-VIII Pay sand, which indicates paleo current direction is towards SW. Which can be interpreted that NE part in the vicinity of that well is having more perspective.

Recommendation

Few wells may be drilled at the northern part of the well L#33 and south-western part of the field around the well L#37 for development of K-VIII Pay Sand.

Results

*Two wells (XXXX & YYYY) have been drilled after the study. Log features and computed petro-physical parameters of both the wells are matching what was estimated through the study. The both the wells are tested at K-VIII pay and are producing Oil from K-VIII Pay. Well No: XXXX drilled northern part of well L#33 is producing presently: QLiq: 20m³/day, W/C:1%, Qoil:19.8 m³/day and Qgas:3500 m³/day. Well No: YYYY drilled south western part of L#37 is producing presently: QLiq: 16m³/day, W/C:1.2%, Qoil:15.81 m³/day and Qgas:2000 m³/day.*

K-IX Pay Sand

- K-IX Pay sand has very well developed at the central part, at the vicinity of wells L#15 & L#25. Petrophysical parameters (Av.VCL, effective porosity, water saturation, net pay thickness, HCPT contour map) contour map have presented in Fig:8-Fig:11 respectively.
- From image log K-IX pay sand appears to be fine lamination of sand & shale (Fig:12). Dips are within 5-10 deg SW. In some of the wells sediment flow direction is towards NNE. It appears that SW direction will have better facies development in the immediate vicinity to the well L#37.

Recommendation: few wells for K-IX pay may drilled towards SW part of the well L#37.
**Figure 1a:** Correlation of the wells of northern part of the field from west to east

**Figure 1b:** Correlation of the wells of Central part of the field from west to east

**Figure 1c:** Correlation of the wells of southern part of the field from west to east

**Figure 2:** Average clay volume fraction Contour Map of K-VIII Pay Sand

**Figure 3:** Average effective porosity Contour Map of K-VIII Pay Sand

**Figure 4:** Average water saturation Contour Map of K-VIII Pay Sand

**Figure 5:** Net pay thickness Contour Map of K-VIII Pay Sand

**Figure 6:** Net Pay Hydrocarbon porosity thickness Contour Map of K-VIII Pay Sand
Figure 1a: Correlation of the wells of northern part of the field from west to east.

Figure 1b: Correlation of the wells of Central part of the field from west to east.

Figure 1c: Correlation of the wells of southern part of the field from west to east.

Figure 2: Average clay volume fraction Contour Map of K-VIII Pay Sand.

Figure 3: Average effective porosity Contour Map of K-VIII Pay Sand.

Figure 4: Average water saturation Contour Map of K-VIII Pay Sand.

Figure 5: Net pay thickness Contour Map of K-VIII Pay Sand.

Figure 6: Net Pay Hydrocarbon porosity thickness Contour Map of K-VIII Pay Sand.
**Figure 7:** Static image, Dynamic image, dips & dip pattern against of K-VIII Pay Sand in a well.

**Figure 8:** Average clay volume fraction Contour Map of K-IX Pay Sand.

**Figure 9:** Average effective porosity Contour Map of K-IX Pay Sand.
Figure 7: Static image, Dynamic image, dips & dip pattern against of K-VIII Pay Sand in a well.

Figure 8: Average clay volume fraction Contour Map of K-IX Pay Sand.

Figure 9: Average water saturation Contour Map of K-IX Pay Sand.

Figure 10: Net pay thickness Contour Map of K-IX Pay Sand.

Figure 11: Net Pay Hydrocarbon porosity thickness Contour Map of K-IX Pay Sand.

Figure 12: Static image, Dynamic image, dips & dip pattern against of K-IX Pay Sand in a well.

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Electrolog Facies Modelling Enables Finding Lateral Continuity & Heterogeneity of Reservoir: A Case Study of Agartala Dome Structure

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Introduction

Agartala Dome is the first subsurface structure identified based on the photogeological studies between the broad synclinal portions of Rokhia & Baramura anticlines. Agartala Dome is basically a concealed structure. The exposed structure Tichna anticline is in its southern side while towards north the structure merges with synclinal area of Bangladesh. It is located about 15 km southeast of Agartala town.

In general, Agartala Dome is a domal structure, plunging towards north and south with nominal dip. In east and west, the structure is bounded by longitudinal reverse faults trending NNW-SSE with throws of 10-20m. The Dome is bisected by EW trending transverse faults, thereby sub-dividing Agartala Dome into fault Blocks, which controls the distribution of hydrocarbons.

It was discovered by the discovery well AD#1 in the year 1987 and so far 44 wells have been drilled on the structure (Figure-1). The field was put on production in 1998. It has multi-layered reservoirs and so far 14 pay sands have been established out of which 6 are in Upper Bhuban and 8 in Middle Bhuban Formation.

A particular pay sand 'X' has been subdivided into 'XA' and 'XB' due to occurrence at different stratigraphic level.

There are some issues regarding the production history of both these sands.

For example in one of the wells i.e., AD#15 the tested sand earlier identified as AP-XA and after taking production for few years the same layer has been renamed as AP-XB. So the layers have to be established based on petrophysical data and reservoir inputs.

Unlikely some up-dip wells e.g. well no. AD# 26 has produced water from AP-XB as compared to wells AD#15 and AD#6 which has produced huge amount of gas from the same layer. Similarly down-dip wells AD# 35 & 7 are gas producer from AP-XB as compared to AD#1 showing little or no influx from the same layer (Figure-2).
Objective

The objective of this study is to delineate the lateral variation of both these sand layers i.e., AP-XA and AP-XB within the structure and to resolve the ambiguity where up-dip wells are giving influx of gas with water and down-dip wells are producing gas from the same layer.

Methodology

Nearly 20 wells of Agartala Dome has been reprocessed and re-evaluated for this study. Old wells have been re-processed using ELAN and recent wells have been revisited and correlated to understand the ambiguity.

Various cross-plots and correlation profiles both in N-S and E-W directions were made to delineate the lateral continuity of AP-XA and AP-XB sands within the structure.

Various Geological inputs were integrated in the study with the help of Forward Base and Sub Surface Team of Agartala to understand the depositional environment and lateral extension of the objective sands. Inputs of pressure profiles, production data and seismic data of the producing sands (AP-XA & XB) were also incorporated to establish the study.

Discussion

Logs of each well were re-visited and re-processed in ELAN Plus module of Geoframe and the petrophysical parameters such as PHIE, Sw and pay thickness were re-evaluated based on logs. No proper information of PHIE, Sw and pay thickness were available earlier due to lack of processed data. Reprocessing of old wells lead to realistic petrophysical information which may help in taking better testing decision. Beside re-evaluation these wells were correlated both along the N-S direction and E-W direction.

Petrophysical evaluation based on log correlation

- Based on the production details three correlation profiles were made in N-S direction. Well no AD#16, 12, 1, 27A, 27, and 41 taken in profile-I and well no. AD#22, 39, 2, 40 and 26 are taken in profile-II. Well no. AD#7, 35, 15, 6 and 42 are taken in profile-III (Figure-3). These three profiles have been compared based on petrophysical inputs as well as production details and reservoir studies.
- In profile-I & II i.e., in well no. AD#1, 2, 22, 27, 27A, 26, 12, 16, 39, 40 and 41 both the sands AP-XA and AP-XB are found to be well developed and log signatures of both the layers were resembling same features in all these wells (Figure-4). No commercial production has been taken from any of these above mentioned wells.
- In profile-III AP-XB sand was found to be well developed in almost all the wells and is gas producer whereas AP-XA layer is developed in few wells only and is found to be not interesting from hydrocarbon point of view.
- To understand the Geological aspect and depositional setting of these wells two profiles (Profile-IV & Profile-V) have been made in E-W direction. Well no. AD# 15, 35, 1, 27A, 27, 22 and 41 were taken in profile-IV and well no. AD#6, 42, 2, 26 and 40 were taken in profile-V (Figure-5). In Profile-IV it is found that the log features of well no. AD#15 and 35 were varying from log features of well no. AD#1, 27A, 27, 22 and 41. In profile-V it has been observed that AD# 6 and 42 are having similar log features at the level of AP-XB sand whereas AD#2, 26 and 40 having different log signature (Figure-6).
In AP-XA sand no production–pressure history is available as no well is completed in this sand.

Well AD#06 and AD#35 completed in AP-XB, are gas producers and have pressure production history of about 12 years. The production performance of AD#06 and AD#35 in AP-XB sand (till Sept'2013) are presented in Figure-7 and Figure-8 respectively.

Well AD#07 produced about 1.17 MMm\(^3\) of gas for meager period from AP-XB sand and ceased to flow due to water loading and has been abandoned as it was watered out. Another well AD#15, produced 85500 m\(^3\)/day of gas with 12 m\(^3\)/day of water through 6 mm bean during initial testing from AP-XB pay. Due to water loading well could not be put on production. In AD#42 the initial pressure was found to be low as compared to other wells in the same pay sand. Presently the well is non-producing. SBHP measurement in different wells in this sand at different time is tabulated in Table-III. The production performance as well the SBHP measurement of wells in this pay sand at different time interval (till 2013) is shown in (Figure-9).

Available pressure data indicate that AD# 6, AD# 7, AD#15 and AD#35 are hydro-dynamically connected (Figure-10).

This pay sand has produced about 662 MMm\(^3\) (Feb-2016) of gas mainly from AD# 6 and AD#35.

The production detail of these wells has been compared in Table I and reservoir data has been compared in Table-II.
Reservoir Inputs

- In AP-XA sand no production-pressure history is available as no well is completed in this sand.
- Well AD#06 and AD#35 completed in AP-XB, are gas producers and have pressure production history of about 12 years. The production performance of AD#06 and AD#35 in AP-XB sand (till Sept’2013) are presented in Figure-7 and Figure-8 respectively.
- Well AD#07 produced about 1.17 MMm3 of gas for meager period from AP-XB sand and ceased to flow due to water loading and has been abandoned as it was watered out. Another well AD#15, produced 85500 m3/day of gas with 12 m3/day of water through 6 mm bean during initial testing from AP-XB pay. Due to water loading well could not be put on production. In AD#42 the initial pressure was found to be low as compared to other wells in the same pay sand. Presently the well is non-producing. SBHP measurement in different wells in this sand at different time is tabulated in Table-III. The production performance as well the SBHP measurement of wells in this pay sand at different time interval (till 2013) is shown in (Figure-9)
- Available pressure data indicate that AD# 6, AD# 7, AD#15 and AD#35 are hydro-dynamically connected (Figure-10).
- This pay sand has produced about 662 MMm3 (Feb-2016) of gas mainly from AD# 6 and AD#35.
- The production detail of these wells has been compared in Table I and reservoir data has been compared in Table-II.
Seismic Inputs

- Seismic study also been carried out in basin level to resolve the ambiguity of these layers. The seismic study consists of nearly the same set of wells as taken for log correlation.

- The seismic interpreted cross-section along log correlation Profile-I & II (Well no. AD1_AD27A_AD27_AD41_AD22_AD39_AD40_AD2_AD26) is showing that the AP-XA and AP-XB sand are developed throughout the section. The log correlation of both the sands is following the seismic reflector trend and can be interpreted to have good reservoir facies along the section (Figure-11).

- Another N-S seismic section along the eastern flank of Agartala dome following Profile-III (as per log correlation) is showing a continuous trend of the AP-XB sand. The AP-XB sand seems to be continuous along the cross-section (Figure-12) but the lithological facies can be resolved as having poorly sorted reservoir. The AP-XB sand has not been picked in the profile.

- While comparing the seismic cross section along the E-W correlation profile (Profile-IV & V) it has been observed that the wells towards the western side of the cross-section (AD#41, 27 & 39 and AD# 26, 2 & 40) in Figure-13 & 14 are showing similar reflector trend at the level of AP-XA and AP-XB sand. The AP-XB sand in wells toward the eastern side (AD# 15 and AD#6 & 42 in Figure-13 and Figure-14 respectively) are having poorly sorted reservoir facies. This can be observed from the velocity variation in the seismic section as there are regions of high impedance contrast and low impedance contrast.
Observations

Based on the correlation profiles, petrophysical studies, Seismic inputs and various inputs of pressure data it has been analyzed that:

- The sands AP-XA and AP-XB have been developed within two separate channels. The wells in profile-I and profile-II i.e., well no AD# 16, 12, 1, 2, 27, 27A, 22, 26, 39, 40 and 41 are falling in one channel (say Channel-I) and the wells in profile-III i.e., 7, 35, 15, 6 and 42 are falling in another channel (say Channel-II) (Figure-3).
- Both the sands AP-XA and AP-XB are well developed in the first channel (Channel-I) and are clearly identified on logs.
- In AP-XA pay sand of Channel-I, the bottom part is clean and seems to be water bearing whereas its top part is silty in nature.
- Log features delineate that the top part of sand AP-XA of Channel-I seem to be interesting from hydrocarbon point of view. Some of these wells have been tested in AP-XA out of which AD# 22 has produced gas @ 68400 m3/d with w/c of 19.2m3/d through 8 mm bean on initial testing. Well AD#26 has produced marginal gas along with high water cut during initial testing. No commercial production has been taken from these wells till date. Other wells such as AD#1, 27, 27A, 39, 40 and 41 have shown little influx or no activity. Since the top part of this sand is appearing to be prospective (Figure-15) so before concluding the result of this pay sand further testing of this layer with proper stimulation is recommended to conclude the presence of commercial quantity of gas. As, none of these wells has been flown for commercial production therefore; no pressure study is available for these wells except AD#22 in which high initial pressure was reported during testing.
- Another sand AP-XB of Channel-I which has developed in all the wells and has been tested in well no. AD#1, 1, 2 and 26. In AD#26 it has flowed water whereas in other wells it shows little or no influx. Based on processed logs AP-XB in Channel-I has been found to be water bearing and does not seems to be interesting from hydrocarbon point of view.
- While correlating the log features of AP-XA sand within Channel-II, it is found that the layer is either missing or poorly developed. But the log features of AP-XB sand are matching and well developed in all the wells (Figure-16). This AP-XB pay sand is interesting from hydrocarbon point of view. Well no. AD#7, 35, 6, 15 and 42 are tested in AP-XB and has produced commercial quantity of gas.
- The available reservoir pressure (SBHP) of AP-XB sand in well no. AD# 7, 35, 6 & 15 is showing that the layer is hydro-dynamically connected (Figure-10).
- While looking at the E-W correlation profiles i.e., Profile-IV and V, it has been observed that the wells falling under Channel-I i.e., well number AD#1, 27A, 27, 22, 41 (Profile-IV) and well number AD#2, 26 and 40 (Profile-V) are having similar lithological facies in AP-XB sand. The facies can be described by cylindrical shape of gamma ray which indicates well sorted sand grains. Whereas the AP-XB pay sand in wells falling under Channel-II i.e., well no. AD# 15 and 35 (Profile-IV) and well no. AD#6 and 42 (Profile-V) is comparatively shaly/silty in nature (Figure-6).
- Again while comparing the feature of AP-XA sand in both the profiles (correlation Profile-IV & V) it has been observed that the AP-XA sand is showing a fining upward sequence in AD#35 (Profile-IV) and AD#42 (Profile-V). Whereas the respective wells falling under Channel-I i.e., well no. AD# 1, 27A, 27, 22 and 41 in Profile-IV and well no. AD#2, 26 and 40 in Profile-V are showing better reservoir facies (Figure-6). Thus showing that both the channels are having different depositional setting.
- Even from seismic cross-section (Figure-13 & figure-14) it has been observed that while moving towards east to west in the structure there is a remarkable difference in the impedance contrast of the reflectors indicating there is a variation in lithological facies which can further be associated with differential depositional environments while moving laterally.
Conclusions

The various geological inputs, log motifs, ELAN processed results, seismic and reservoir inputs suggest that

- There may exist two separate channels say Channel-I and Channel-II in the eastern part of Agartala Dome structure.
- In Channel-I, both the sands AP-XA and AP-XB are well developed. However AP-XB pay sand is devoid of hydrocarbon potential but AP-XA pay sand seems to be interesting from hydrocarbon point of view.
- The top part of AP-XA sand of Channel-I is silty in nature and is interpreted to have hydrocarbon potential. But its bottom part is comparatively clean and interpreted to be water bearing. The porosity and permeability of the top part of this layer might have been affected due to silty nature of the reservoir. So further proper stimulation/testing of this layer is required.
- In Channel-II the AP-XB pay sand is well developed in all the wells and has produced commercial quantity of gas. Though the layer is comparatively shaly/silty w.r.t. the AP-XB sand developed in Channel-I, it is interpreted as having good hydrocarbon potential and interesting from commercial point of view.
- The AP-XA pay sand developed in few wells within Channel-II is interpreted to be not interesting from hydrocarbon point of view.
- In AD#15 the producing sand (2962 – 2974 m) was initially identified as AP-XA and later renamed as AP-XB. Based on this study it has been observed that the log features and pressure history of this sand interval is matching with AP-XB sand. Hence, the layer in the interval 2962 – 2974 m can be established as AP-XB sand.

Recommendations

- Based on present study it can be concluded that there may exist two separate channels in the eastern part of Agartala Dome structure.
- In Channel-II more wells are recommended to be drilled for AP-XB pay sand. But prior to drilling a well detailed geological and seismic study must be carried out to understand its lateral extension, channel axis and orientation.
- The AP-XA pay sand of Channel-I must be tested with proper stimulation to establish the status of commercial quantity of gas in this layer.
- Well no. AD#39 and AD#41 are recommended for testing in AP-XA sand. The evaluated petrophysical parameters and recommended perforation intervals are presented in Table-III.
## Recommendations

- Well no. AD#39 and AD#41 are recommended for testing in AP-XA sand. The evaluated petrophysical parameters and recommended perforation intervals are presented in Table-III.
- The AP-XA pay sand of Channel-I must be tested with proper stimulation to establish the status of commercial quantity of gas in this layer.
- In Channel-II more wells are recommended to be drilled for AP-XB pay sand. But prior to drilling a well isolation by cement plug after initial testing is required.
- Based on present study it can be concluded that there may exist two separate channels in the eastern part of Agartala Dome structure.

## Conclusions

- In AD#15 the producing sand (2962 – 2974 m) was initially identified as AP-XA and later renamed as AP-XB. Based on this study it has been observed that the log features and pressure history of this sand interval is matching with AP-XB sand. Hence, the layer in the interval 2962 – 2974 m can be established as AP-XB sand.
- In Channel-II the AP-XB pay sand is well developed in all the wells and has produced commercial quantity of gas. Though the layer is comparatively shaly/silty w.r.t. the AP-XB sand developed in Channel-I, it is interpreted as having good hydrocarbon potential and interesting from commercial point of view.
- The AP-XA pay sand developed in few wells within Channel-II is interpreted to be not interesting from hydrocarbon point of view.
- The top part of AP-XA sand of Channel-I is silty in nature and is interpreted to have hydrocarbon potential but AP-XA pay sand seems to be interesting from hydrocarbon point of view.
- In Channel-I, both the sands AP-XA and AP-XB are well developed. However AP-XB pay sand is devoid of hydrocarbon point of view.
- Based on the geological inputs, log motifs, ELAN processed results, seismic and reservoir data, it is interpreted that 

## Testing details of wells in the layer AP-55A & AP-55B

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Layer Name</th>
<th>Perforated Interval</th>
<th>Gas rate m3/d</th>
<th>Water rate m3/d</th>
<th>Bean size</th>
<th>Initial Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>AD#1</td>
<td>AP-XA</td>
<td>2859 – 2863 &amp; 2868 - 2870</td>
<td>-</td>
<td>-</td>
<td></td>
<td>Negligible influx of water with gas</td>
</tr>
<tr>
<td></td>
<td>AP-XB</td>
<td>2913 – 2920 &amp; 2917 – 2935 (add‘ perf.)</td>
<td>-</td>
<td>-</td>
<td></td>
<td>Influx of water with little gas</td>
</tr>
<tr>
<td>AD#2</td>
<td>AP-XB</td>
<td>2907.5 – 2913.5</td>
<td>-</td>
<td>-</td>
<td></td>
<td>No influx</td>
</tr>
<tr>
<td>AD#22</td>
<td>AP-XA</td>
<td>2844.0- 2848.0m</td>
<td>44400</td>
<td>10.8</td>
<td>6</td>
<td>Isolated by cement plug after initial testing</td>
</tr>
<tr>
<td>AD#27A</td>
<td>AP-XA</td>
<td>2848 - 2851</td>
<td>-</td>
<td>-</td>
<td></td>
<td>No Activity</td>
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<tr>
<td>AD#39</td>
<td>AP-XA</td>
<td>2847 - 2850</td>
<td>-</td>
<td>-</td>
<td></td>
<td>No Activity</td>
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<td>AD#26</td>
<td>AP-XA</td>
<td>2831-2834m</td>
<td>-</td>
<td>-</td>
<td></td>
<td>Marginal gas producer with high water production.</td>
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<tr>
<td></td>
<td>AP-XB</td>
<td>2887-2888.5 m</td>
<td>-</td>
<td>-</td>
<td></td>
<td>Flowed Water</td>
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<tr>
<td>AD#40</td>
<td>AP-XA</td>
<td>3020-3025 &amp; 3027-3030</td>
<td>-</td>
<td>-</td>
<td></td>
<td>No influx</td>
</tr>
<tr>
<td>AD#41</td>
<td>AP-XA</td>
<td>2925 - 2928</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>No Activity</td>
</tr>
<tr>
<td>AD#16</td>
<td>AP-XA</td>
<td>2907 - 2912</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Influx of water @ 29 m3/d</td>
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<tr>
<td>AD#7</td>
<td>AP-XB</td>
<td>2978 - 2982</td>
<td>42296</td>
<td>3.12</td>
<td>6</td>
<td>After 2nd CSQ job. Re-perforation interval is 2978.5-2981.5m</td>
</tr>
<tr>
<td>AD#35</td>
<td>AP-XB</td>
<td>2945 - 2948</td>
<td>80016</td>
<td>-</td>
<td>6</td>
<td></td>
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<tr>
<td>AD#6</td>
<td>AP-XB</td>
<td>2920.0-2924.0 &amp; 2928.0-2934.0</td>
<td>113,000</td>
<td>-</td>
<td>6</td>
<td>Commercial Gas producer</td>
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<tr>
<td>AD#15</td>
<td>AP-XB</td>
<td>2963-2966 &amp; 2970.5-2973.5</td>
<td>85550</td>
<td>12</td>
<td>6</td>
<td>Gas producer</td>
</tr>
</tbody>
</table>
### SBHP measurements of studied wells at different time interval

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Layer Name</th>
<th>SBHP (KSC)</th>
<th>Datum Pressure</th>
<th>Date</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>AD#7</td>
<td>AP-XB</td>
<td>281.6</td>
<td>281.8</td>
<td>Dec-1998</td>
<td>Well produced for only 2 months</td>
</tr>
<tr>
<td>AD#35</td>
<td>AP-XB</td>
<td>233.12</td>
<td>234.19</td>
<td>31-Jul-2012</td>
<td>Gas producing well, Starts production from Dec’12.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>226.45</td>
<td>227.68</td>
<td>6-Aug-2013</td>
<td></td>
</tr>
<tr>
<td>AD#6</td>
<td>AP-XB</td>
<td>306.20</td>
<td>306.31</td>
<td>1-Dec-1989</td>
<td>Gas Producing well</td>
</tr>
<tr>
<td></td>
<td></td>
<td>305.50</td>
<td>305.60</td>
<td>1-Nov-1999</td>
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<td></td>
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<td>222.14</td>
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<td>28-Jun-2013</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>196.37</td>
<td>200.86</td>
<td>16-Dec-2014</td>
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<tr>
<td>AD#15</td>
<td>AP-XB</td>
<td>277.93</td>
<td>286.21</td>
<td>23-Mar-2007</td>
<td>Planned for abandonment</td>
</tr>
<tr>
<td></td>
<td></td>
<td>248.32</td>
<td>256.52</td>
<td>14-Nov-2008</td>
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<tr>
<td></td>
<td></td>
<td>213.28</td>
<td>225.95</td>
<td>9-Apr-2009</td>
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<td>26-Feb-2012</td>
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<td>AD#42</td>
<td>AP-XB</td>
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<td>207.7</td>
<td>23-Apr-2015</td>
<td>Non flowing/Unconnected</td>
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<tr>
<td></td>
<td></td>
<td>214.13</td>
<td>214.0</td>
<td>5-Apr-2016</td>
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</table>

### Wells Recommended for Perforation

<table>
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<tr>
<th>Well NO.</th>
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<th>Recommended Perforated Interval (m)</th>
<th>PHIE (%)</th>
<th>Sw (%)</th>
</tr>
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<td>AD#39</td>
<td>AP-XA</td>
<td>2846 - 2850</td>
<td>10</td>
<td>70 - 75</td>
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<tr>
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<td>AP-XA</td>
<td>2925 - 2930</td>
<td>10</td>
<td>65 - 70</td>
</tr>
</tbody>
</table>
References

1. Simulation study of all pay sands of Agartala Dome based on New Geological Model submitted by A&AA
Identification of Stratigraphic Interfaces and Calculation of Hurst Exponent for Lithology Characterization using Wavelet Transform: A Study Conducted on Korba Coalfield

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Abstract

Well logging operations are undertaken for petrophysical studies and a lot of capital is involved. It is pertinent that we extract maximum information from well logs. In this study we demonstrate a methodology to identify formation stratigraphic interfaces using Wavelet Transform and further classify them using their Hurst Exponent to uniquely identify and characterize them. We have used natural gamma ray and single point resistivity logs in our study. This dataset pertains to the Korba coalfield in Madhya Pradesh, India. The objective of this study is to uniquely identify and distinguish between coal, shalycoal, carbonaceous shale, and shale which were recorded in the logs. It is quiet challenging in uniquely distinguishing between these layers and becomes even more challenging in accurately estimating the reserves of the reservoir and for further mine planning. In this study we first use Discrete Wavelet Transform (DWT) and Fourier Transform (FT) to identify the stratigraphic interfaces from well logs and use it to identify lithologies and potential bed boundaries. This is used as an input in the next part of the analysis where we use Continuous Wavelet Transform (CWT) analysis in determining the Hurst Exponent for each of the lithologies and use it for uniquely characterizing them.

Introduction

In the exploration of hydrocarbons it is very pertinent that maximum information is extracted from geophysical surveys as a lot of time and money is invested in acquiring them. For surveys pertaining to coal extraction, it is one thing that coal seams have been identified, but it is a totally different scenario when they are extracted. The quality of coal seams is often questioned and it is very difficult to accurately study them through geophysical surveys. In this analysis we are able to delineate the finer variations of coal seams from well logs through a combination of techniques. We firstly use an approach combining Discrete Wavelet Transform (DWT) and Fourier Transform (FT) to identify the stratigraphic interfaces from well logs and use it to identify lithologies and potential bed boundaries. We then use Continuous Wavelet Transform (CWT) to uniquely characterize the different lithologies.

Stratigraphic information has been extracted from well logs in the past (Igbokwe 2011, Li et al. 2014, Mory and Iasaki 1996). The SP and gamma ray logs have been used as they have good responses to changes in lithology. Walsh Transform has been in the past to identify bed boundaries (Lanning and Johnson, 1983). Continuous Wavelet Transform has been used in the past to identify bed boundaries (Verma et al. 2012, Choudhury et al. 2007). It has also been used to detect electroracies association from well logs and extract stratigraphic information (Perez-Munoz et al. 2013, Panda et al. 2015). In this study we use Single Point Resistivity (SPR) logs and gamma ray (GR) logs for the analysis pertaining to the Korba Coalfield, Madhya Pradesh, India.

Geology of the Area

The area under investigation consisted of alluvium deposit having average thickness of 2-20m. The major coal seams in the area are of Upper Barakar formation of the Lower Permian age. The basic lithology of the Upper Barakar formation consists of hard to fine-coarse grained ferruginous sandstone and grey shale. The coal seams present are thick and are interbanded with shaly coal and carbonaceous shale. The average thickness of Barakar formation is about 480m. The basement consists of Archaen rocks having granites, gneisses, schists and amphibolites. Coal is primarily formed in a reducing environment and therefore it is often associated with the presence of carbonaceous shale. The coal seams alternate with carbonaceous shale and are also often intermixed with shale. The zone which has been selected and taken in this analysis consists of alternating beds of coal, shaly-coal, carbonaceous shale, and shale.
Methodology

The wavelet analysis is very useful in analysing non-stationary signals and provides both depth and frequency domain localization (Perez-Munoz et al., 2013). The continuous wavelet operation can be defined by Eq. 1 (Boggess and Narcowich 2001; Misti et al., 2000).

\[ W(a,b) = \frac{1}{\sqrt{|a|}} \int_{-\infty}^{\infty} f(t) \psi \left( \frac{t-b}{a} \right) dt \]  

Here the log signal is given as \( f(t) \), \( W(a,b) \) are the wavelet coefficients, \( \psi \) is the mother wavelet, \( a \) and \( b \) are the scale and translation parameters respectively. Mathematically this operation can be seen as a convolution operation between the log signal and the mother wavelet. The scale parameter is inversely proportional to the frequency of the signal and the translation parameter is the rate at which the mother wavelet is shifted along the log signal in the convolution operation (Polikar 1999). In the continuous wavelet operation the changes in the scale and translation parameters happen in a continuous manner, but in a discrete wavelet operation this shift happens in dyadic powers (based on powers of 2 or \( 2^j \)). The result of the DWT operation are a pair of coefficients namely the Approximation Coefficients (CA) and the Detail Coefficients (CD). The CA coefficients are the result of a low pass filtering operation and the CD coefficients are a result of a high pass filtering operation. The DWT analysis for an input log signal can be defined by the following set of equations (Misti et al., 2000; Yue et al., 2004):

\[ CA_k^j = \sum f(t) \psi(t-b) \]  

\[ CD_k^j = \sum h_b(t-2b)CA_{k}^{j-1} \]  

\[ h_{b} = \frac{1}{\sqrt{2}} \int_{-\infty}^{\infty} \varphi(t/2)\varphi(t-b)dt \]  

\[ h_{b} = \frac{1}{\sqrt{2}} \int_{-\infty}^{\infty} \varphi(t/2)\varphi(t-b)dt \]  

\[ R_{CD}^j = \sum h^*(t-2y).CD_{k}^{j-1} \]  

In the above equations the mother wavelet is orthogonal to and is the complex conjugate of the mother wavelet. The CA and CD coefficients are calculated for every iteration \( j \) as defined in Eq. 2, 3 & 4. The reconstruction of the detail coefficients gives back the reconstructed signal as given in Eq. 7. The Eq. 5 & 6 are a linear combination of the scaling function and the wavelet function which are used as weights when reconstructing the signal.

The Fourier Transform of a signal gives a very good frequency decomposition, but does not give any depth information at the same time. In this analysis the FT analysis is done after the DWT analysis as we need only those set of frequencies which contain the stratigraphic information as they have a characteristically high amplitude when plotted in the frequency domain. The FT analysis works, as any non-periodic signal can be represented in the Fourier domain, and well log signals in general are not periodic and are treated as non-stationary in the analysis. The Fourier Transform can be calculated through the DFT (Discrete Fourier Transform) operation as shown in Eq 8 & 9 (Oppenheim et al., 1999; Wickerhauser 1994):

\[ F_n = \sum_{k=0}^{N-1} F_n e^{2\pi in k/n} \]  

\[ F_k = \sum_{n=0}^{N-1} F_n e^{2\pi in k/n} \]
The log signal in time (depth) domain is and in frequency domain it is in the above equations. In this analysis we have used the Fast Fourier Transform (FFT) method (Cooley and Tukey, 1965) to do the FT analysis. The number of computations if \(2N\) in the DFT analysis, gets drastically reduced to \(2N\log_2 N\) in the FFT operation.

Stratigraphic interfaces are geological changes occurring in the strata and are very well recorded in log responses as variations in the amplitude and frequency of the signal. The changes can be due to micro and macro variations in the depositional environment. These changes can be better visualized using a combination of Discrete Wavelet and Fourier Transform (Srivardhan V 2016; Srivardhan et al., 2016; Bappa et al., 2016) analysis.

The log signal is first DWT analysed using a suitable mother wavelet. In this analysis we used the 'db-1' wavelet from the Daubechies family of wavelets as they gave good results as compared with other wavelets. In this analysis the gamma ray logs and SPR logs were used for delineating the stratigraphic interfaces. The gamma ray log is very sensitive to the lithological changes as there is a lot of high frequency changes in the log signal due to the statistical nature of lithology as compared to the SPR log. The dataset was therefore initially filtered using DWT analysis to remove the high frequency variations. For gamma ray logs a 3 level decomposition was necessary to remove the high frequency variations, while a single level decomposition was good for SPR logs. In the process of decomposition, the corresponding \(CA\) coefficients were selected for the \(j\)th decomposition level. The signal was then reconstructed back using only the \(CD\) coefficients and the same mother wavelet.

The reconstructed signal was then Fourier Transformed using Eq. 8 and the power spectrum of the coefficients was plotted and the set of frequencies corresponding to maximum amplitude were filtered and inverse transformed using Eq. 9 to get the modified reconstructed wavelet coefficients which were then logarithmically transformed according to Eq. 10 (Jang and Jang, 2003; Srivardhan V 2016) to obtain the log transformed (LT) response. The LT response was then plotted with depth which gave the variations in the stratigraphic interfaces. The results are plotted in Fig. 1.

\[
LT = \log 2 \left[ \log \left( \frac{M_{Recd}}{440} \right) \right] + 69 \quad \text{(10)}
\]

We assume that there is a power law relation hidden in the log signal, which comprises of amplitude and frequency variations to characterize a given lithology. This relationship can be exploited using CWT analysis. We assume that there is a power law relationship between the variance of wavelet coefficients \(W(a,b)\) and the scale of analysis in the CWT operation of log signals. The CWT analysis of a log signal is defined in Eq. 1. The log signal can be divided into many stratigraphic units based on the results of the DWT-FT analysis and in each unit we can perform a CWT operation to exploit the power law relation to uniquely characterize that unit. The power law relation can be defined through Eq. 11, where \(H\) is the holder exponent.

\[
\text{Var}(w(a,b)) \propto a^H \quad \text{(11)}
\]

The log signal in each stratigraphic unit based on the DWT-FT analysis was CWT analysed using the 'db-2' wavelet from the Daubechies Family of Wavelets as it best described this power law relationship. A plot of scale and variance of wavelet coefficients on a log-log plot gave a straight line whose slope is characterized by the Holder Exponent. There is a linear relationship between the Holder Exponent and the Hurst Exponent \(h\), which is described in Eq. 12.

\[
2h = 1 = \frac{5 - H}{2} \quad \text{(12)}
\]

In this analysis we varied the scale factor between 1 and 15 as low scales corresponds to higher frequency variations, and we found that the signal deviates significantly from the power law at higher frequencies. The results of the analysis are presented in Fig 2a & b.
Observations

The results of the DWT-FT analysis can be seen in Figure 1. For GR and SPR logs. Based on the geological information of the region, the depth interval of concern mainly consists of Shale, Carbonaceous shale, coal, and shaly-coal respectively. From Fig. 1 the signature of shale can be identified when the strength of the log scaled response increases with depth (like a transgressive pattern) and when the strength of the log scaled response decreases with depth (like a regressive pattern) it is coal. The increase and decrease in amplitude in between represents shaly-coal and carbonaceous shale. This is kind of pattern is seen in both the responses of GR and SPR logs from Fig. 1. Based on the responses the observations were recorded and the minor lithofacies variation were tabulated in Table 1.

**Table 1**: The Lithofacies identified through DWT-FT analysis.

<table>
<thead>
<tr>
<th>S. No</th>
<th>Depth Interval</th>
<th>Lithology</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>397.80-398.20</td>
<td>Shaly-Coal</td>
</tr>
<tr>
<td>2</td>
<td>398.21-398.80</td>
<td>Carbonaceous Shale</td>
</tr>
<tr>
<td>3</td>
<td>398.81-399.22</td>
<td>Shaly-Coal</td>
</tr>
<tr>
<td>4</td>
<td>399.23-399.70</td>
<td>Carbonaceous Shale</td>
</tr>
<tr>
<td>5</td>
<td>399.71-400.30</td>
<td>Shale</td>
</tr>
<tr>
<td>6</td>
<td>400.31-401.02</td>
<td>Shaly-Coal</td>
</tr>
<tr>
<td>7</td>
<td>401.03-401.80</td>
<td>Carbonaceous Shale</td>
</tr>
<tr>
<td>8</td>
<td>401.81-402.10</td>
<td>Coal</td>
</tr>
<tr>
<td>9</td>
<td>402.11-402.50</td>
<td>Carbonaceous Shale</td>
</tr>
<tr>
<td>10</td>
<td>402.51-402.90</td>
<td>Shaly-Coal</td>
</tr>
<tr>
<td>11</td>
<td>402.91-403.20</td>
<td>Coal</td>
</tr>
<tr>
<td>12</td>
<td>403.21-403.60</td>
<td>Carbonaceous Shale</td>
</tr>
<tr>
<td>13</td>
<td>403.61-404.32</td>
<td>Shaly-Coal</td>
</tr>
<tr>
<td>14</td>
<td>404.33-404.65</td>
<td>Coal</td>
</tr>
<tr>
<td>15</td>
<td>404.66-405.36</td>
<td>Shale</td>
</tr>
<tr>
<td>16</td>
<td>405.37-406.13</td>
<td>Shaly-Coal</td>
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<td>17</td>
<td>406.14-406.33</td>
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<td>18</td>
<td>406.34-406.73</td>
<td>Coal</td>
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<td>19</td>
<td>406.74-406.99</td>
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<td>407.04-407.40</td>
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<tr>
<td>21</td>
<td>407.41-407.82</td>
<td>Shale</td>
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</table>
Based on the results of Table 1, the CWT analysis was performed in the depth intervals of the corresponding log signals. The Hurst parameter was calculated for each characteristic lithology and the averaged parameter from GR and SPR logs was considered for each zone. The variation in the Hurst parameter for each zone was noted and a general classification could be brought which characterized each lithology. The results of the CWT analysis are tabulated in Table 2.

**Table 2**: The tabulation of Average Hurst Exponent Range for various lithologies.

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Average Hurst Exponent Range</th>
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<tr>
<td>Shaly-Coal</td>
<td>0.32-0.41</td>
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<td>Coal</td>
<td>0.41-0.47</td>
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<tr>
<td>Carbonaceous Shale</td>
<td>0.47-0.49</td>
</tr>
<tr>
<td>Shale</td>
<td>0.49-0.56</td>
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</table>

**Discussion of results**

In this study we have used the DWT-FT analysis to successfully identify stratigraphic interfaces and we have identified coal, shaly-coal, carbonaceous shale, and shale. Further the obtained results were compared with conventionally interpreted results and it was found that finer stratigraphic sequences could be better deciphered using the DWT-FT analysis and overall agreed with the conventionally interpreted results. The stratigraphic interfaces obtained using the DWT-FT analysis reflects the small scale lithological variations taking places in the formation. They also indicate the level of purity of the coals in a qualitative manner. The bed boundaries were used to divide the log signal, and for each part the Hurst Exponent was calculated using CWT analysis. The Hurst Exponent calculated, characterized each part of the interpreted lithology uniquely and was also used as an indicator to reinterpret the lithology obtained through conventional methods. The Hurst exponent also represents a quantitative indicator of the quality of coal reservoir. The Hurst Exponent tabulated in Table 2, reflects the combined average of the Hurst Exponents calculated from SPR and GR logs. It can be seen that Shaly-Coal and has a wide variation in Hurst Exponent, which indicates the level of contamination in coal. There is very little variation in Carbonaceous Shale as seen in the Hurst Exponent. The Carbonaceous Shale is that shale which develops in a reducing environment. Since coal is formed in a reducing environment, it alternates with carbonaceous shale which is more abundant than shale. In the DWT-FT analysis, the Carbonaceous Shale would have a lesser response as compared to Shale. In this manner shale and Carbonaceous Shale were differentiated. The methodology was found to be very useful in identifying thin bands which were not seen earlier through conventional interpretation techniques. The thinnest bed which characterized a unique facies was 0.13m, detected as Carbonaceous Shale. The methodology is very useful in facies mapping and understanding the variation in facies with depth. The Hurst Exponents calculated can also be used for correlating between beds as dissimilar depositional systems of the same lithology would have a different frequency-amplitude variation, resulting in a different Hurst Exponent. The study indicates that the DWT-FT analysis can be used to identify minor stratigraphic variations and the CWT analysis can be used to characterize every individual facies variation with depth. The study was successful in identifying and characterizing the facies variation in the Korba Coalfield.
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Identifying Hydrocarbon Accumulation and Fingerprinting of Migration Pathways using Sonic Wave Crossplot Technique

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Introduction

The presence of hydrocarbon in the pore spaces of a reservoir rock has known to have a strong influence on acoustic properties of both compressional (P) and shear (S) waves. Prediction of lithology and pore fluid are the major objectives in any reservoir characterization studies (Gir, R², 1990). Over last two decades numerous geoscientists have studied the full wave sonic and have published very interesting results. Compressional wave, Shear wave, Stoneley waves etc. have always evoked great interest in classical seismology. With the advent of 3-component geophones, further advanced studies were conducted to understand the earth's elastic properties in detail. Seismic response of a rock is mostly expressed by two seminal properties: the amplitude and the velocity, determined by elasticity and density of the rock. In addition to elastic properties, pore shape and texture, especially anisotropic texture, such as bedding or fractures can influence the seismic character.

However, one needs to keep this in mind that in borehole acoustic imaging (basic sonic tools) shear waves can neither be generated inside borehole nor received by the hydrophones mounted on the tool. Further, different terminology has been used by different authors for the same acoustic wave as pointed out by Crain E.R, CWLS, 2004. Moreover, recent studies have identified two types of borehole shear waves - direct and indirect, also known as refracted or induced. Indirect shear waves are induced in a formation through a process known as mode conversion in which some of the compressional energy is transferred from the borehole fluid into the rock formation.

A new cross plot technique for highlighting the light hydrocarbon bearing zones from non-hydrocarbon bearing zones in clastic reservoirs has been conceived and tested in Deepwater wells of ONGC which has been discussed in detail in this paper. This methodology has also been successfully tested in wells of western and southern region of Indian basins, such as Cauvery basin, Cambay basin and Assam-Arakan basin. Poisson's Ratio (PR) versus Shear-Impedance (Vs-Imp) cross plot has found to be an innovative tool to differentiate the hydrocarbon bearing zones more prominently than rest of the zones.

Theoretical background

Compressional ($V_p$) and shear wave velocities ($V_s$) can be expressed in terms of elastic moduli and bulk density of the rock:

\[ V_p = \sqrt{K + \frac{4}{3}\mu} / \rho \]
\[ V_s = \sqrt{\mu / \rho} \]

Where:
- $K$ = Bulk modulus
- $\mu$ = Shear modulus
- $\rho$ = Bulk density

Shear-wave propagation requires a medium that has shear strength (rigidity). Consequently, shear waves can only travel in solids, not in liquids or gas. In liquids and gas, the shear head-wave generated within the formation is converted into a compressional wave and propagated back across the borehole fluid to the acoustic receivers as a later-arriving compressional wave.
Unconsolidated or poorly consolidated sandstones ("soft" or "slow" rocks) are less rigid and more compressible than well-consolidated ("hard" or "fast") rocks. When the formation shear-wave velocity is less than the acoustic velocity of the borehole fluid ($V_s < V_p$), a rock formation is called "slow." There is no refracted shear-wave from monopole devices in slow formations and low-frequency dipole transmission and reception is required to adequately detect low-frequency flexural arrivals for the shear-wave slowness determination. However, if a monopole-array tool is used in these conditions, a shear-wave slowness can be estimated from Stoneley-wave velocity dispersion. In very slow formations, where $V_p < V_s$, special processing may be required to extract the formation compressional signal.

Traditionally, the travel time of compressional wave was used as porosity tool for given lithology and travel time of shear wave was helpful in determining mechanical rock properties. Interpreters use the shear modulus for distinguishing sand quality because it is generally unaffected by reservoir fluids. Identification of degree of compaction and effective stress through cross plot techniques was studied by Rao et al., 2004. In fact, the shear wave velocity in gas-saturated sands found to be slightly faster than the shear velocity in brine-saturated sands.

It has been found that compressional wave is sensitive to the saturating fluid type. The fact that compressional wave velocity ($V_p$) decreases and shear wave velocity ($V_s$) increases with the increase of lighter hydrocarbon saturation, makes the ratio of these two velocities more sensitive to change of fluid type than isolated use of either velocities. In majority of cases, the effect can be seen as crossover when both velocities are plotted together, lighter the hydrocarbon larger is the size of the cross over. The use of the $V_p/V_s$ ratio versus sonic travel time, $V_p/V_s$ ratio versus P-Impedance and Poissons Impedance (Quackenbush et al., 2006) versus Shear Impedance are well known techniques in identifying fluid type but actual application of this methodology in deep water settings is not widely available in the public domain. The $V_p/V_s$ ratio versus Compressional travel time (DTc) cross plot is generally used to differentiate hydrocarbon bearing zones from water bearing zones.

**Methodology**

In the current study, initially 16 wells of deep water area were scrutinized and the log data was thoroughly checked vis-à-vis the available theoretical crossplots such as $V_p/V_s$ vs Acoustic Impedance, DTc vs $V_p/V_s$ etc. When the log data was found to be in coherence then the new innovative crossplot technique was experimented in all the wells. It has been found that the hydrocarbon bearing points follow totally a different trend on Poisson’s ratio (PR) versus Shear Impedance ($V_s$-Imp) cross plot whereas other shale and sand points follow a hyperbolic trend (Fig. 1a) and it separates the hydrocarbon bearing points more clearly than the former known crossplot techniques. Lighter the hydrocarbons more will be the separation from the main trend as clearly shown in Fig. 1b in case of wells A & B. The aforesaid out-of-box technique was then successfully used in other wells of eastern, western and southern region of Indian basins. In Fig. 2 one well is shown from western region in which log curves as well as testing data supports the new cross plot technique.
Figure 1b: PR - VS Impedance Multiwell crossplot; Lighter the hydrocarbon more the degree of separation between the main non hydrocarbon bearing cluster and hydrocarbon bearing cluster

Figure 2: one well is shown from western region in which log curves as well as testing data supports the new cross plot technique.

Figure 2: Poisson's ratio (PR) versus Shear Impedance (Vs-Imp) cross plot in Well-C, hydrocarbon bearing points gets separated from main trend
Figure 1b: PR - VS Impedance Multiwell crossplot; Lighter the hydrocarbon more the degree of separation between the main non hydrocarbon bearing cluster and hydrocarbon bearing cluster.

Figure 2: Poisson’s ratio (PR) versus Shear Impedance (Vs-Imp) cross plot in Well-C, hydrocarbon bearing points gets separated from main trend.

Figure 3a: In Well-D conventional logs indicated the presence of water but possibly the migrated hydrocarbon left its fingerprints in the compressional and shear travel times.

Figure 3b: Seismic section of Well-C. Well-C lies on the flank (seen as bright amplitude on seismic section).
During the log analysis of Well-D of Deep water area where the well is lying at the flank of bright spot and PR-Vs Imp crossplot is also showing the presence of hydrocarbon but on testing it produced water with poor influx of gas (Fig. 3a and 3b). Possibly due to migration of hydrocarbon from flank towards updip side. The acoustic logs showing hydrocarbon signature but on testing it is indicating other way round. So, the migrated hydrocarbon lefts its fingerprints in compressional and shear travel times. Therefore, if a well is drilled at a later stage in the updip direction then that can be prospective from hydrocarbon point of view. Thus, the above cross plots technique is not only helpful in determining the hydrocarbon accumulation but if combined with seismic attributes and other geological data, it could be used to determine the direction of migration of hydrocarbon in the field. Thus, this technique could be useful while identification of new prospective location in the field.

Moreover, in Well-E it has been observed that the hydrocarbon bearing points (on testing found to be gas bearing) lie in different cluster than the migrated hydrocarbon points but both follow the same trend and are at appreciable distance from the main trend (Fig. 4).

Figure 4: Well-E; hydrocarbon bearing points (on testing found to be gas bearing) lie in different cluster than the migrated hydrocarbon points but both follow the same trend

Seismic (amplitude and velocity sections) can provide an overview of presence of good reservoir (water or HC or any other fluid are not differentiable) in the field and sometimes it is not able to locate the thin (< 3 ms) reservoirs rather but this technique is helpful in isolating light hydrocarbon bearing reservoir from rest of the non- hydrocarbon bearing ones either thick or thin. This new crossplot technique can also be used as a well site quick-look method to identify zones for further testing. In the Fig. 5, the encircled portion indicates hydrocarbon bearing zone which could not be identified on seismic but was easily distinguishable through cross plot technique and was found to be gas bearing.

Conclusions

The new crossplot technique (PR – Vs Impedance), can easily distinguish the hydrocarbon bearing points from non-hydrocarbon bearing points in a clastic reservoir. Thus it may be referred to as a new direct hydrocarbon detection method and therefore can be used as quicklook method to identify the light hydrocarbon bearing prospective zones in a well. When clubbed with seismic and other geological data, it can be used to detect direction of migrated hydrocarbon and exploration in that direction can assist in locating new prospective zones in the field.

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5) wiki.aapg.org/Well_log_analysis_for_reservoir_characterization
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Figure 5: Hydrocarbon bearing zone in Well-F which could not be identified on seismic but was easily distinguishable through new cross plot technique

Conclusions

The new crossplot technique (PR – Vs Impedance), can easily distinguish the hydrocarbon bearing points from non-hydrocarbon bearing points in a clastic reservoir. Thus it may be referred to as a new direct hydrocarbon detection method and therefore can be used as quicklook method to identify the light hydrocarbon bearing prospective zones in a well. When clubbed with seismic and other geological data, it can be used to detect direction of migrated hydrocarbon and exploration in that direction can assist in locating new prospective zones in the field.

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Combined NMR and Formation Pressure Testing While Drilling Saved Cost and Added Value for Perforation Decisions in Western Offshore India

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Abstract

Nuclear magnetic resonance (NMR) logging is widely accepted and used extensively for formation evaluation because it provides lithology-independent porosity, pore size distribution, and permeability estimation or permeability index. In India, this technology has been mainly used on wireline and has proven its value. Acquisition of NMR data, though, has required extra acquisition time and rig time. Recently, due to the promising performance and increased confidence in logging-while-drilling (LWD) data, normal practice is to acquire the maximum amount of data during drilling. This approach is particularly applicable when drilling highly deviated or horizontal wells, to mitigate risk and the possibility of non-suitable wellbore conditions for wireline data acquisition.

The combination of NMR and formation pressure testing while drilling is the best combination that obtains quality data for formation evaluation and reservoir analysis. This combination saves rig time for selection of depths to conduct pre-tests. The permeability index curve and T-2 distribution help in selecting the test type and in reducing excessive time taken for pre-tests in tight zones. Rig time savings also are realized; wiper trips before wireline logging are eliminated as are possible stuck situations with wireline tools while acquiring formation pressures in highly deviated wells. This paper discusses a successful use of NMR and formation pressure testing while drilling (FPWD) services along with the conventional triple-combo LWD tool suite to drill and record drilling parameters and formation evaluation data simultaneously in a challenging wellbore environment.

Introduction

The subject well is an exploratory well drilled in Western Offshore Basin, India. It was drilled to explore the hydrocarbon potential of a sandstone formation. Acquisition of formation evaluation data while drilling is very useful in drilling exploratory wells where the degree of uncertainty is relatively high. No valid pore pressure measurements or acoustic logs from offset wells were available to calibrate the geo-mechanical model. Consequently, it became important to acquire formation pressures while drilling to minimize the pore pressure uncertainty and to minimize risks associated with wellbore stability. With this in mind, a penta-combo LWD bottomhole assembly (BHA), which included resistivity, gamma ray, neutron and density porosity, NMR and FPWD tools, was used to drill this vertical well (Fig. 1).

The data from these tools, including a sixteen-sector azimuthal density image and the T2 distribution spectrum from the NMR tool, were transmitted in real time through mud pulse telemetry. A gas influx was observed where the well had to be shut in. The mud weight was increased gradually to control the kick. After 48 hours the well was under control and the string remained stationary in the open hole for this time. The stuck string was released and the plans to drill the well further in the same section were cancelled. After circulation at the bottom for hole conditioning, formation pressure measurements were made using the FPWD tool. Considering the wellbore stability issues associated with this well, the wireline logging program for this section was cancelled to avoid a stuck tool situation. It was decided to case off the current section and to continue drilling to the target depth in the following section. Three zones of interest were identified based on the combined analysis of LWD formation evaluation logs and formation pressures measured using the FPWD tool. The well was perforated at the zones of interest and a straddle packer assembly on wireline recovered fluid samples at these zones.
Identifying appropriate depths for FPWD pressure testing

The LWD tool gave three measurements of porosity from bulk density, neutron porosity and nuclear magnetic resonance. Because this deployment was the first of its kind in India, the data from conventional porosity measurements using radioactive sources and from NMR tools containing no radioactive sources were studied further and compared. Based on these studies, the use of radioactive sources for porosity measurements could be avoided in the future. Because the NMR-derived porosity was independent of lithology, it required very minimum environmental or hydrocarbon corrections. In addition, it was possible to quantify effective porosity from total porosity using the NMR data, after the lithology was determined. Porosity partitioning, pore size distribution and permeability index are important calculated values that assist in identifying and understanding the zone of interest and the T2 distribution (Fig. 2). These LWD logs were monitored in real time during acquisition. Observations showed that the default T2 cut-offs for the sandstone formation worked well in the water-bearing zone. Consequently, the T2 cut-offs values were set to 3.3ms for clay-bound water and 33ms for capillary-bound water.

After comparing the NMR-derived porosity and the density-neutron response, probable zones were identified by matching the density-neutron crossover and higher values for mean T2 on the T2 distribution spectrum. NMR permeability index and partial porosities were analysed to determine suitable depths for pressure testing. To identify the most suitable depths to conduct the pre-tests, the better permeability depths compared to the relatively lower permeability zones in the same interval were chosen. This process helped to optimize the pressure testing program and saved operational time by minimizing repetitive pre-tests in low-permeability or tight zones.

Comparison of pressure testing data obtained from FPWD tool and Straddle Packer

Because this was an exploratory well, pressure testing was attempted at some depths that had already been tested using the FPWD tools, and fluid samples were recovered. Formation pressure measured using the FPWD tool was compared to that measured using a straddle packer. The following important observations were made:

- The pressure recorded using the FPWD tool compared very well with those measured using the straddle packer (Fig. 3). Generally, formation pressures measured using wireline tools are considered the most reliable. This experience proved the reliability of the pore pressure data obtained by the FPWD tool in a dynamic drilling environment.
- In spite of testing in a vertical well profile, no-seal situations were not observed while testing with the FPWD. Reciprocating and de-torquing the drillstring ensured that the string remained stationary throughout the duration of the test.
- At some depths, the FPWD tool was successful in measuring stabilized and repeatable formation pressures while the straddle packer showed tight/ dry tests (Fig. 3). Generally, a straddle packer is successful in measuring formation pressures where the probe based tools fail since it tests an interval and achieves higher drawdown pressures. In this case, the zones being tested are more than 3m in thickness, which is greater than the testing interval (typically 0.5m) in a straddle packer. Also, the zones for testing with the straddle packer were chosen such that the mobile zone indicated by the permeability index curve and FPWD results was in the middle of the testing interval. Hence, the possibility that the probe based FPWD tool measured pressures in a high mobility zone neighbouring an overall tight zone which may have led to insufficient flow to the straddle packer while testing the same interval can be ruled out. This may be due to the formation damage that occurred from the time the well was static to completion and cementing.
In a few instances, the straddle packer measured lower formation pressures as compared to those measured by the FPWD tool (Fig. 3). This difference in formation pressures measured in dynamic drilling conditions and cased hole conditions after the well had remained static and can be linked to the time elapsed since drilling. The stability achieved may be different because of the additional pressure drop across formation damage, skin and improper perforations.

Significant reduction in mobility was also observed at some depths (Fig. 4). This could be attributed to near-wellbore formation damage and/or improper perforation.

The conclusion was that the formation pressure measurements from both tools used in this case were in good agreement for updating the geomechanical model real time pore pressure prediction. Formation pressure measurements from the FPWD available during the drilling stage were least affected by near-wellbore effects and formation damage.

Advantages of NMR+FPWD penta-combo assembly

A penta-combo LWD BHA, which included resistivity, gamma ray, neutron and density porosity, NMR and FPWD tools, was used for the first time. The run highlighted the following features:

- The combined BHA helped in acquisition of maximum formation evaluation data in a single run. This saved rig time compared to acquiring the same data in multiple runs with wireline tools.
- Because the well became active while drilling, well control and wellbore stability issues made it difficult to run wireline tools; the wireline operation planned for the well had to be cancelled. The use of high-end LWD technology made it possible to acquire accurate openhole formation evaluation data in the drilling run.
- Optimizing the pressure testing program based on inferences from mud logs and LWD logs (Fig. 4) helped obtain faster measurements of pressure tests during circulation, reducing the risk of the tool becoming stuck while it was stationary at a given depth during pressure testing.
- The perforation and well testing decisions (Fig. 1) were made based on the LWD log data recorded in this section and the results from the formation pressure testing while drilling operation. Pore size distribution and partial porosities calculated from the NMR response were useful in deciding the perforation intervals.
- Measuring formation pressure in real time using FPWD tools added more value in terms of calibrating pore pressure profiles in geomechanical models and avoiding well control situations.

Conclusions

The paper focuses on a case where wellbore stability and well control problems prohibited lowering any wireline tools in the well in openhole conditions. Because wireline logs could not be run, acquiring the data by LWD was crucial. The acquisition of NMR data while drilling, coupled with the conventional logs, was useful in optimizing the depths for conducting pre-tests while pulling out of hole. The paper also explains how this data, further integrated with the results from pre-tests, was then used to identify three main objects for perforation and testing. Measuring formation pressure in real time using FPWD tools added more value in terms of calibrating pore pressure profiles in geomechanical models and avoiding well control situations. Employing LWD technology provides an efficient means for hazard and risk mitigation in challenging wells while saving rig time by avoiding additional time required for wireline runs to acquire the same data.

This paper describes a case where the integrated use of advanced LWD tools resulted in a significant saving of more than $850K to the operating company, along with the availability of critical data for petro-physical evaluation and identification and selection of zones for testing.
In a few instances, the straddle packer measured lower formation pressures as compared to those measured by the FPWD tool (Fig. 3). This difference in formation pressures measured in dynamic drilling conditions and cased hole conditions after the well had remained static and can be linked to the time elapsed since drilling. The stability achieved may be different because of the additional pressure drop across formation damage, skin and improper perforations.

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Figure 1: The penta-combo LWD bottomhole assembly (BHA), which included resistivity, gamma ray, neutron and density porosity, NMR and FPWD tools, was used to drill this vertical well.
Figure 2: A combined log showing potential hydrocarbon-bearing zones and their corresponding permeability indices from NMR, pressure tests recorded using FPWD tool and the objects selected for perforation and testing based on the obtained results.
Figure 3: A plot showing formation pressures measured at certain depths using the FPWD tool and straddle packer. At some depths, formation pressure could not be measured using straddle packer due to formation damage.

Figure 4: A plot showing the mobility calculated at certain depths using the FPWD tool and straddle packer. Mobility calculated from the straddle packer data shows a significant decrease as compared to the mobility obtained from the FPWD data. This reduction in mobility is due to the formation damage and invasion.
Figure 5: The composite log showing openhole formation evaluation data and mud logging data. The zone of interest has significant gas shows as per the mud log.
Prediction of Shear Wave Velocity from Recorded Compressional Velocity in Shaly Sandstone Reservoir using Empirical Relationship: A Case Study of East Coast, India

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Keywords

Compressional Velocity, Shear Velocity, Empirical relation, Rock Physics Modelling, Shaly Sand Reservoir

Abstract

Shear wave velocity logs are useful for quantitative seismic interpretation through amplitude variation with offset (AVO) and inversion studies for exploration and exploitation of hydrocarbon. In many developing or developed oil/gas fields, only compressional wave velocity data is available from old sonic tools. Some times, recorded shear velocity data quality is poor due borehole rugosity, mud-filterate invasion and limited depth of investigation/vertical resolution of wireline tools. The recorded shear velocity is also affected by scattering of sonic waveform due to sudden lithological variation in thinly laminated/heterogenous and anisotropic reservoirs resulting into low signal to noise ratio. Therefore, prediction of shear velocity (Vs) from recorded compressional velocity (Vp) through an area specific empirical relation is required for seismic reservoir characterization and geomechanical studies.

In the present paper, an attempt is made to establish an empirical relationship between recorded compressional wave velocity Vp and predicted shear wave velocity Vs through a scientifically sound rock physics modelling of shaly sandstone reservoir in 19 studied wells. The two different empirical relationships have been established in the studied wells; one for hydrocarbon bearing reservoirs and the other for water bearing reservoirs and shales sections. These empirical relationships have been validated in other two wells in the same field where good quality shear data recorded with new generation tools i.e. Sonic scanner tool (Schlumberger) and X-Mac (Baker Hughes) is available. An excellent correlation is observed between predicted and recorded shear wave velocities. These empirical relationships have been further used in the same area for prediction of shear wave velocity in shallow sections in the wells where only recorded compressional wave velocity Vp is available and used in Geo-mechanical study of the field. The study can be extended in other fields of the basin with similar geological setting/depositional environment, thus saving time and money. The predicted shear wave velocity from empirical relationships can directly be used with confidence in AVO/inversion for seismic reservoir characterization for prospect generation.

Introduction

The present study deals with the prediction of shear wave velocity in shaly sandstone reservoirs of KG offshore basin, East Coast, India. The location map of study area is in Fig.-1. The study covers oil and gas reservoirs of Pliocene/Pleistocene age of Godavari clay formation.

Shear velocity logs are generally not recorded due to high cost or well complications. Further, some times in the recorded shear velocity data may be affected by bad borehole condition or formation heterogeneities. Therefore, prediction of shear velocity (Vs) from recorded compressional velocity (Vp) through an area specific empirical relation is very much helpful in seismic reservoir characterization and geomechanical studies. However, the empirical relationship has to be established through a scientifically sound rock physics modelling and validated with good quality bore hole shear data.
Prediction of Shear Wave Velocity from Recorded Compressional Velocity in Shaly Sandstone Reservoir using Empirical Relationship: A Case Study of East Coast, India

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Shear velocity logs are generally not recorded due to high cost or well complications. Further, sometimes in the recorded shear velocity data may be affected by bad borehole condition or formation heterogeneities. Therefore, prediction of shear velocity (Vs) from recorded compressional velocity (Vp) through an area specific empirical relation is very much helpful in seismic reservoir characterization and geomechanical studies.

However, the empirical relationship has to be established through a scientifically sound rock physics modelling and validated with good quality bore hole shear data.

Figure 1: Location Map of Study Area
Methodology and Workflow

The shear wave velocity is generated in Geolog software through rock physics modelling in all 19 wells in the study area using grain contact theory based rock physics models suitable for unconsolidated shaly sand reservoirs.

Methodology and workflow for predicting shear wave velocity from recorded compressional velocity

1. Loading/splicing/merging/depth matching/de-spiking of log data.
2. Conditioning of log data.
3. Environmental corrections of log data.
4. Regression analysis and generation of empirical relations between Vs predicted from rock physics modelling and recorded Vp.
5. Validation of shear velocity predicted from empirical relationship with recorded shear velocity in two wells with sonic data with new generation sonic tools.
6. Predictation of shear velocity using the empirical relations in wells where recorded shear wave data is not available.

Discussion of Results

A regression analysis was done between predicted shear velocity (Vs) from rock physics modelling carried out in 19 wells spread across the field and recorded compressional velocity (Vp). The following second degree polynomial relations are generated for hydrocarbon bearing zones and water bearing zones/shale sections as shown in Fig.-2 & Fig.-3.

1) For hydrocarbon bearing zones, with correlation of coefficient 80%.
2) For water bearing and shale sections, with correlation coefficient 94.7%.

\[
V_s = 0.9238115336 + 1.16V_p \quad \text{(1)}
\]

In industry, there are many methods available for prediction of shear velocity such as empirical relations between Vp & Vs, multivariate regression, artificial neural network etc. Many empirical relationships exist in the industry for prediction of shear velocity, but, in most cases, the results are not desirable due to following reasons:

1) Various area specific parameters affecting the shear velocity may not be included in empirical relationship.
2) The empirical relationship valid for a given geological setting may not be applicable in the study area due to different lithological association, fluid distribution and internal reservoir structure.
3) Most of the relationships are based upon laboratory studies carried out on limited set of core samples at ambient conditions of temperature & pressure using synthetic fluids.

The most popular linear relation, published by Castanga et. al (1985) that relates compressional (Vp) to shear (Vs) velocities for water-saturated clastic rocks in Gulf of Mexico may not valid in other geological environments. The correlation known as mudrock line is given by:

\[
V_s = 1.36 + 1.16V_p(km/s)
\]

Another non-linear empirical relation proposed by Carroll (1969) to predict shear velocities from compressional velocities of rock samples is:

\[
V_s = 1.09913326 + V_p^{0.9238115336} km/s \quad (2)
\]

In this present paper, empirical relationships have been established from data generated through an appropriate rock physics modelling validated with new generation tools like Sonic scanner tool and X-MAC with good borehole data. The shear wave velocity Vs generated through rock physics modelling after a robust petrophysical evaluation is free from all the borehole environmental effects.
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(1) For hydrocarbon bearing zones, with correlation of coefficient 80 %.

\[ V_s = -408.931 + 0.676956V_p + 7.02257 \times 10^{-7}V_p^2 \]  

(3)

(2) For water bearing and shale sections, with correlation coefficient 94.7 %.

\[ V_s = -408.931 + 0.676956V_p + 7.02257 \times 10^{-7}V_p^2 \]  

(4)

Figure 2: Hydrocarbon bearing zones (CC: 80 %)

\[ V_s = 408.931 + 0.676956V_p + 7.02257 \times 10^2V_p^2 \]

Figure 3: Water bearing and shale sections (CC: 94.7%)

\[ V_s = -1225.608 + 1.09257V_p - 5.97436 \times 10^{-5}V_p^2 \]
These empirical relationships have been validated in two blind wells A and B, where new generation sonic tools recorded shear data was available for validation.

**Well-A**

The processed outputs i.e., porosity, water saturation & mineralogical volumes along with basic wireline logs of well-A for the interval 2541-2780 m is shown in Fig-4. In this well, deep reading new generation acoustic tool i.e. sonic scanner was deployed to record compressional velocity (Vp) & shear velocity (Vs). Sonic scanner tool being deep reading tool and less affected by borehole has been used for validation. The shear velocity is also predicted using empirical relations. In the hydrocarbon bearing intervals: 2560-2565m, 2580.5-2598, 2645.6-2662.5, 2712-2715 & 2723-2729 m, Vs is predicted by using eq.(3) and in rest water bearing & shale sections by eq. (4). An excellent match between predicted Vs by empirical equation and recorded Vs by sonic scanner tool, against hydrocarbon/water bearing zones and shale sections, proves the efficacy of the methodology and accuracy of the empirical relationships as shown in track-5 of Fig.-4.

**Well-B**

The composite log of well-B for the interval 2375-2575 m is shown in the Fig.-5. The composite log consisting of petrophysical processed and basic log curves. In this well, compressional velocity (Vp) & shear velocity (Vs) is recorded by X-MAC new generation sonic tool. The shear velocity is successfully predicted using the established empirical relationships. For prediction of Vs in the well, eq.(3) is used for hydrocarbon bearing layer interval 2436-2492 m and rest part in water reservoir or shaly sections eq(4) is used. A very good match is observed between recorded Vs and predicted Vs, which proves the accuracy of empirical relationships.

These empirical relationships are further used in 8 wells of the same area for prediction of shear velocity in shallower horizons for geo-mechanical study. Shear data has not been recorded in these wells for shallow depths. The Vs logs predicted using these equations in the wells C, D and E are presented in Fig.-6. In these wells, prediction of shear velocity is useful in Geo-mechanical studies of KG-98/2 area for safe drilling and completion during development phase.

**Conclusions**

This study brings out robust empirical relations for prediction of shear velocity from recorded compressional velocity (Vp) for Pliocene-Pleistocene reservoirs in KG-98/2 area. The study can be extended in other fields of the basin with similar geological setting/depositional environment, thus saving time and money. The predicted shear wave velocity from empirical relationship can directly be used with confidence in AVO/inversion for seismic reservoir characterization and geo-mechanical studies.

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*NB. The views expressed in this paper are solely of the authors and do not necessarily reflect the view of ONGC.*
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Figure 4: Composite of Well: A, A good match between predicted Vs by empirical relation & recorded Vs by sonic scanner tool proves the efficacy of the methodology and accuracy of the empirical relationships. (track 5).
Figure 5: Composite of Well: B. A good match between predicted Vs by empirical relation & recorded Vs by X-MAC tool proves the efficacy of the methodology and accuracy of the empirical relationships. (track 5)
Figure 6: Composite Log of Wells: C, D & E: Predicted shear velocity Vs through empirical relations (track 4) from Recorded Vp (track 3) for Geo-mechanical study in KG-98/2 area
Identification of Bypassed / Leftover Hydrocarbons in Brown Field Reservoirs of Rajahmundry Asset: Some Case Studies
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Abstract
Determining the left over hydrocarbon saturation behind the casing and its exploitation in depleting reservoirs is always challenging. Periodic measurement of saturations behind casing helps in diagnosing the production problems such as water influx and water injection breakthrough where injection is going on. It helps in planning the work over jobs for better exploitation of hydrocarbons. Declining oil & gas production, increased water cut, growing operating costs, integrity challenges due to aging facilities are all factors that can lead to brownfield, becoming operationally and economically unviable. As reservoirs mature, the available energy to drive hydrocarbons depletes often leading to reduced production rates and reserves recovery. As reservoirs deplete, leftover hydrocarbons can be bypassed and become trapped. Well surveillance and time to time interventions can identify and potentially remediate this problem. These bypassed / left over hydrocarbon zones can be identified by recording casedhole logs such as RST, CHFR and CNL under suitable conditions and put wells back to production. In this paper a case study each of time lapse CNL, RST and CHFR results in Rajahmundry Asset is presented. These wells were ceased earlier due to water loading and put on production after recording logs.

Introduction
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Kesanapalli west field
Kesanapalli West field is one of the main oil producing fields of Rajahmundry Asset. It consists of multi-layered oil & gas pay sands having limited areal extent in Matsyapuri formation. The field was discovered in 1996. The hydro-carbon bearing zones in the field have been found to be concentrated in two separate culmination located in NE & SW directions. Sofar, 47+ 7ST wells have been drilled on the two culminations and 27 hydro-carbon bearing layers in NE culmination & 27 in SW culminations have been demarcated. Layers thickness is few meters to tens of meters with vertical & horizontal in-homogeneities.

Kesavadasupalem field
Kesavadasupalem field was discovered in May-1998. The field was put on production in Nov-98 through the well KV#1. Kesavadasupalem is a NE-SW trending doubly plunging anticline situated along the east coast in East Godavari district of Andhra Pradesh between Mori prospect in the northeast and GS- 49 (offshore) prospect in the southwest. Sofar, 34 wells have been drilled on the structure and 21 gas pays have been encountered.
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Reservoir Saturation Tool (RST)

Formation sigma and the inelastic C/O ratio are the two measurements most frequently used in reservoir evaluation and saturation monitoring through casing. Because oil and fresh water have nearly the same neutron capture cross section (sigma), formation water salinity must be sufficiently high and of known value to compute saturation from sigma. If the formation water is fresh or the salinity is unknown, saturation is derived from the salinity-independent C/O ratio measurement. The basic principle of C/O mode is that hydrocarbons have carbon and virtually no oxygen and water has oxygen but no carbon. Hence in a porous rock, as the hydrocarbon replaces water, carbon concentration increases and oxygen concentration decreases. Therefore the ratio of Carbon to Oxygen increases. The RST tool works on this principle.

Figure 1: Prospective map showing Kesanapalli west & Kesavadasupalem fields

Figure 2: Schematic picture showing RST C/O ratio method
Casedhole formation resistivity (CHFR)

CHFR tool is like a laterolog device where the resistivity is calculated by measuring voltage, that is generated by injecting current in the formation and the resistivity could be computed, if the amount of the current and the voltage drop is measured. But, in the case of cased hole, conductive casing restricts the current to penetrate into the formation. Thus a low frequency current with high skin depth could leak into the formation and this leakage current measurement helps to find the resistivity of the formation. Before calculating the saturation of depleted zone, CHFR log is compared with the open hole log of non-depleting zones.

The degree of depletion of reservoir is calculated by taking the ratio of resistivity in open hole to cased hole.

Figure 2: Schematic picture showing CHFR tool measurement principle

Casedhole CNL

CNL (Compensated neutron) log has been useful for identifying gas zones in openhole conditions when used in combination with the FDC (Compensated density log). In wells drilled with fresh mud, there is usually enough unflushed gas in the invaded zone that the CNL porosity is gas effected and is lower than the actual total porosity.

A casedhole CNL log recorded during or after filtrate dissipation indicates increasing gas saturation when compared to the openhole CNL log if flushed zone liquid saturation is decreasing with time. Additionally, since the excavation effect on CNL porosity values in gas bearing formations also increases with decreasing water saturation, the casedhole CNL porosity exhibits an enhanced gas effect.
The comparison of openhole Vs casedhole CNL logs has been useful in identifying shaly gas formations as well as in better defining reservoir gas liquid contacts. This comparison brings information about the gas depletion status after due normalization at water bearing & shale sections. This comparison technique has offered an improved, positive log analysis for identifying depleted/non depleted gas zones for water shut off jobs and zone transfers during workover jobs.

**Discussion of case studies**

Rajahmundry Asset is having vertically stacked multiple oil and gas sands in complex reservoirs. Pressure depletion in sands and early water loading is a major challenges across the fields. Majority of the wells are posing problems due to increasing water cut and ceased due to water loading. The methodology adopted to revive the sick wells and monitoring depleted/non flowing wells are time lapse CNL for gas reservoirs and CHFR & RST for oil reservoirs. Selection of CHFR/RST is basically depends on the salinity contrast of oil and water sands across various fields of Rajahmundry Asset. Recording of these logs in all vertically stacked oil & gas sands wherever possible helps to cancel/modify the work over plans after finding complete/partial depletion on logs. Furthermore these results save costly rig time by modifying the existing plan. Appreciable oil & gas gain was obtained through CNL/RST/CHFR logging.

In this paper a case study each of time lapse CNL, RST & CHFR results in Rajahmundry Asset is presented. These wells were ceased earlier and put on production after recording logs.

**Case study I – RST logging**

The well -1 was a side tracked S'- profile well drilled in 2008 to exploit hydrocarbons from Konukollu sandstone. As per log interpretation, this sand is oil bearing in the interval 2198-2213m with porosity 12-24% and water saturation 40-60%. On initial testing, sand-2 in the interval 2198-2208m has produced Oil @ 20.5m³/d and Gas @ 28,000 m³/d thru 6mm choke with FTHP-575psi. Later, the well ceased to flow oil due to water loading.

RST log was recorded in Feb-2012 to identify oil saturation depletion within this sand. The log shows a non-uniform depletion, the top part of the interval 2198-2203m is showing high depletion compared to bottom interval 2203-2213m. This nonlinear depletion may be due to intercalated shale streaks, relative permeability and lack of vertical permeability in the reservoir. After carrying out cement squeeze job in the interval 2198-2208m, selectively perforated the interval 2203-2208m (Fig-1) which produced oil of 20m³/d with little water cut. The oil production gradually decreased with time and finally well flowed only water.

Reviewed open hole logs again and observed a tight streak in the interval 2208-2209m. Based on the assumption that this streak can act as barrier for the vertical movement of the fluid and the saturation on RST log, perforated below the tight streak in the interval 2210-2212m. This zone has produced oil @ 46m³/d initially. Thus the RST log helped in recovering the leftover hydrocarbons in the reservoir.

![Figure 1: Case study example from RST logging](image)
Case Study- II - CHFR logging

The Well-2 was a side tracked well and drilled to exploit hydrocarbons from Sands developed within Matsyapuri sandstone Formation. As per log interpretation, Sand-17B is gas bearing in the interval 1907-1914m with porosity 22-32% and water saturation 15-60% and Sand-17A is oil bearing in the interval 1916-1930m (OWC: 1919m) with porosity ~32% and water saturation ~20%. Initially Sd-17A was perforated in the intervals 1909–1910 & 1910.5–1912m which produced Qo-33.6m³/d, Qg- 11090 m³/d through 5mm bean initially. The oil production gradually decreased with time and finally well started flowing only water. To know the latest water saturation and to revive the well, recorded CHFR in sand-17A and sand-17B. The log shows that the resistivity against sand 17-B is reduced from 70-100 ohm.m to 0.5 to 0.9 ohm.m and sand 17-A is reduced from 40 ohm-m to 5 ohm-m. This indicates that the existing zone sand 17-B is completely depleted and the bottom zone sand-17A is still having some higher oil saturation. Based on these results, sand 17-A was perforated in the interval 1916.5-1917.5m which produced oil@10m³/d & Gas@ 16,000m³/d.

The CHFR results showed that the sands 17-B and 17-A are not depleted uniformly and still some hydrocarbon is left in sand 17-A (Fig-2). Thus the CHFR log helped in reviving the well successfully and put the well back in to production.

Case study III - CNL logging

The well-3 was a side tracked well to exploit hydrocarbons from sands developed within Matsyapuri sandstone Formation. Based on log interpretation, Sand-12B is gas bearing in the interval 2242-2249.5m with porosity 12-22% and water saturation 10-35%. In 2009 the interval 2242-2245m was perforated which produced Gas@71,000m³/d, condensate @ 9m³/d and thru 6mm choke with FTHP-2442psi. With time the water cut gradually increased and finally the well ceased to flow.

Cased hole CNL was recorded to know the depletion of sand-12B and latest saturations in other hydrocarbon bearing sands (sand-13 for zone transfer) as they are producers from other nearby wells. Against sand-12B, the new CNL log, light blue color curve is departed from the original dark blue color cure and the CNL porosity is increased to the water bearing porosity level and is represented by red color line (water level). It is evident that sand-12B in the interval 2242-2249.5m is completely watered out. In case of sand-13 (2193-2196m) the light blue CNL log is overlay with original CNL log which indicates the hydrocarbons are intact in sand-13.

Hence zone transfer was planned to sand-13. The interval 2193-2194m of sand-13 was perforated which flowed Qc: 20m³/d & Qg: 18,500m³/d, FTHP: 1530 psi thru 6mm choke. The CNL log also shows some reduction against sand 13A which is just above sand-13. In this way the CNL log indicates the time lag saturations of the other pay sands which are producers from other wells. Thus CNL log resolves the issues related current water saturation in cases where gas separation is originally seen between density neutron logs.

Figure 1: Case study example from CHFR logging
Case Study - II - CHFR logging

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Figure 3: Case study example from Casedhole CNL logging
Conclusions

- Hydrocarbons depletion during production is not uniform due to inhomogeneities in the reservoir.
- As reservoirs deplete, leftover hydrocarbons can be bypassed and become trapped. Time lapse recording of casedhole CNL, RST and CHFR logs help to identify bypassed/leftover hydrocarbons.
- Recording of these logs in vertically stacked multiple hydrocarbon zones in the fields like Kesanapalli west and Kesavadasupalem helps in taking decisions for zone transfers or to selectively perforate the existing zones.
- Depletion status of all the vertically stacked sands helps to take remedial steps to improve/enhance HC production. Furthermore, this time to time depletion data provides vital information for future workover jobs or zone transfers of offset wells. This avoids futile zone transfer jobs during deployment of workover rigs. This saves costly rig time and puts wells back in to production.

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Geomechanical Study of Malleswaram Field from Sonic Scanner Logging: A Case Study
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Abstract
Drilling challenges in Krishna Godavari Basin lead to severe NPT and not being able to achieve drilling targets where formation pressures and stress directions are not known. Improper casing policy and mud weights during drilling of these formations leads to borehole instability and rugosity which is a major concern for acquiring good quality data for reservoir evaluation. To understand and minimize these drilling related problems, sonic scanner logging was carried out in three successive wells namely X, Y & Z thus enabling to provide mechanical earth modelling and wellbore stability analysis to mitigate the above problems. The objective of the study was to provide solution for drilling optimization by maintaining proper mud weight to avoid shear failure in the well, characterization of pore pressure and fracture gradient for Hydraulic fracturing optimization.

In this paper, a case study from the Malleswaram field is presented to show how an iterative Geomechanics based approach integrating products from advanced sonic scanner tool has significantly improved the stability of the borehole by reducing the drilling-related problems like mud loss, held ups, tight pulls and stuck ups.

Introduction
Malleswaram field is located in KG basin with proven Oil reserves in Nandigama formation which belongs to late Jurassic to early Cretaceous age. Nandigama formation is a low porosity and low permeability reservoir. Upper Raghavapuram shale lying on the Nandigama formation is sticky in nature. 8 ½" openhole section of most of the wells are planned and drilled through Raghavapuram and Nandigama formations. Wells being drilled in this field through these formations are experiencing severe drilling challenges which include drill string stuck-up, frequent held ups, tight pulls etc.

Figure 1: Prospect map of Malleswaram field and structure contour map of wells. X, Y & Z
Geomechanical analysis

Improper casing policy and mud weights during drilling of Raghavapuram & Nandigama formations leads to borehole instability and rugosity which is a major concern for acquiring good quality data for reservoir evaluation. To understand and minimize these drilling related problems, sonic scanner logging was carried out in three successive wells namely X, Y & Z thus enabling to provide mechanical earth modelling and wellbore stability analysis to mitigate the above problems. The objective of the study was to provide solution for drilling optimization by maintaining proper mud weight to avoid shear failure in the well, characterization of pore pressure and fracture gradient for Hydraulic fracturing optimization.

Pore pressure

Pore pressure is an important component in a MEM and critical to the calculation of horizontal stresses, wellbore stability analysis, sand production prediction and other Geomechanics applications. Sonic or resistivity logs can be used to identify pore pressure trends in shale and to calculate the pore pressure. However, the calculated pore pressure needs to be calibrated by pore pressure measurement or drilling data. If pore pressure measurements are available, pore pressure can also be estimated using constant pressure gradients, which can be calculated pressure measurements.

Pore pressure can be measured directly in permeable zones by using openhole MDT/XPT pretest data or by well tests. There are many methods for estimating pore pressure using log data, most of them are effective stress based approaches. Examples Eaton method (Eaton, B. 1975), Equivalent depth method (Foster, J.B. and Whalen, H.E, 1966) or the Bowers method (Bowers, G, 1995).

Pore pressure is estimated using combination of Eaton's and Bower's method at these three wells. Pore pressure ramp is observed in Raghavapuram formation. It increases from 1.1SG at Raghavapuram top to 1.74SG at Raghavapuram bottom.
Identification of pore pressure type

Integration of Geomechanical analysis with sonic scanner and ECS logs led to identification of Type-II overpressure from Raghavapuram shale onwards. Density versus velocity plot (Hoseni, 2004) shows some overpressure points of Raghavapuram and Nandigama formations lie in unloading curve which clearly indicated Type-II overpressure in those formations which can be due to faulting, fluid migration, clay diagenesis etc. Chemical diagenesis refers to the chemical alteration of minerals by geologic processes, and is thought to be a principle cause of abnormal pressure (McClure, 1983). For example, temperature increases during rock deposition may cause Montmorillonite family clays to dehydrate and turn into Illite (Powers, 1967). Water that was formerly bound to the Montmorillonite is thus released to occupy pore space. Because free water occupies more space than bound water, it becomes over pressured if held in by a low-permeability seal (Fig-7). Iron versus silica and aluminum versus silica cross-plots indicated presence of Illite in these formations (Fig-8).

**Figure 3:** Secondary overpressure generation mechanism can be detected using velocity and density analysis (modified after Hoesni, 2004)

**Figure 4:** Density vs slowness crossplot in well. X

**Fig-5:** Density vs slowness crossplot in well. Y
Stress profile

Overburden stress (vertical stress) is computed by integrating formation density using the equation below, typically formation density obtained from wireline logs

\[ \sigma_v = \rho g z \]

Figure 10: Overburden stress calculation

In an isotropic and tectonic relaxed area, the minimum and maximum horizontal stresses are about the same in magnitude, but horizontal stresses are usually dissimilar where major faults or active tectonics exist. In all cases, the difference between the largest and smallest in-situ principal stresses is governed by the condition of limiting state, in which the peak strength of the rock cannot be exceeded.

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 minifrac or extended leakoff 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/FITs 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.

Where \( \sigma_h = \) minimum horizontal stress, \( \sigma_H = \) maximum horizontal stress, \( \sigma_v = \) overburden stress, \( E_x = \) strain at minimum horizontal stress direction, \( E_y = \) strain at maximum horizontal strain direction, \( \alpha = \) Biot elastic coefficient, \( P_p = \) pore pressure

Figure 6: Density vs slowness crossplot in well. Z

Figure 7: Density vs slowness Multi well crossplot in wells. X, Y & Z

Figure 8: Secondary overpressure clay diagenesis

Figure 9: Fe vs Si and Al vs Si cross-plots indicated presence of Illite in these formations
Stress profile

Overburden stress (vertical stress) is computed by integrating formation density using the equation below, typically formation density obtained from wireline logs

\[ \sigma_z = \int \rho(z) \cdot g \cdot dz \]

\( \sigma_z \) is the overburden stress; \( \rho \) is density; \( g \) is gravity.

\[ \sigma_v = g \int R_h \cdot d \ z \]

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\[ \sigma_h = \frac{v}{1-v} \sigma_s - \frac{v}{1-v} a E_s + \frac{E}{1-v} E_s + \frac{vE}{1-v} E_s \]

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Where \( \sigma_h \) = minimum horizontal stress, \( \sigma_H \) = maximum horizontal stress, \( \sigma_v \) = overburden stress, \( Ex \) = strain at minimum horizontal stress direction, \( Ey \) = strain at maximum horizontal strain direction, \( \alpha \) = Biot elastic coefficient, \( Pp \) = pore pressure.
Calibration of the minimum horizontal stress is conducted using the LOT data and the maximum horizontal stress is adjusted until the predicted failure are in good agreement with the observed borehole failure indicated by the caliper log and borehole images. No extended LOT data or mini-frac data available for wells to calibrate the derived minimum horizontal stress magnitude.

**Figure 11:** Stress profiles of wells. X, Y & Z

- Overburden stress is in the range of 19ppg to 19.25ppg in the Nandigama formation
- In Raghavapuram formation stress regime is Strike slip (SHmax≥Sv≥Shmin) (Fig-11)
- In Nandigama formation stress regime is strike slip (SHmax≥Sv≥Shmin) to thrust regime (SHmax≥Shmin≥Sv) (Fig-11)

**Horizontal Stress direction**

Several methods are available for identifying stress direction from wireline logs including borehole breakout orientation from multi arm calipers & FMI log, natural and drilling induced fractures orientation from FMI log, and shear sonic anisotropy from DSI/Sonic scanner logs. The orientation of a wide breakout is a good indication of the orientation of minimum horizontal stress in a vertical well. Maximum horizontal stress σH is perpendicular to borehole breakout (parallel to drilling induced fractures) and Minimum horizontal stress σh is parallel to borehole breakouts.
Calibration of the minimum horizontal stress is conducted using the LOT data and the maximum horizontal stress is adjusted until the predicted failure are in good agreement with the observed borehole failure indicated by the caliper log and borehole images. No extended LOT data or mini-frac data available for wells to calibrate the derived minimum horizontal stress magnitude.

![Figure 11: Stress profiles of wells. X, Y & Z](image)

- Overburden stress is in the range of 19ppg to 19.25ppg in the Nandigama formation.
- In Raghavapuram formation stress regime is Strike slip ($SH_{max} \geq SV \geq Sh_{min}$) (Fig-11).
- In Nandigama formation stress regime is strike slip ($SH_{max} \geq Sh_{min} \geq SV$) to thrust regime ($SH_{max} \geq SV \geq Sh_{min}$) (Fig-11).

Horizontal Stress direction

Several methods are available for identifying stress direction from wireline logs including borehole breakout orientation from multi-arm calipers & FMI log, natural and drilling induced fractures orientation from FMI log, and shear sonic anisotropy from DSI/Sonic scanner logs. The orientation of a wide breakout is a good indication of the orientation of minimum horizontal stress in a vertical well. Maximum horizontal stress $\sigma_{H}$ is perpendicular to borehole breakout (parallel to drilling induced fractures) and Minimum horizontal stress $\sigma_{h}$ is parallel to borehole breakouts.

![Figure 12: Hole shape analysis in wells. Y & Z](image)

Identification of breakouts on FMI logs in offset wells. A & B

- Stress rotation is observed in Raghavapuram shale and prominent directions of Sigh are observed N20deg to N30deg and N120 to N130deg which are almost 90deg to each other.
- Stress direction in Nandigama formation is N120 to 130deg.

Wellbore Stability

The best way to calibrate a 1-D MEM is to verify the predictability of the model. Using the computed rock properties and horizontal stresses, wellbore stability analysis tells us how good the MEM is by comparing the predicted wellbore stability with the drilling events observations, breakout or tensile induced fractures observed on caliper or image logs. With the available 1-D MEM and the well trajectory, the stress concentrations around the borehole are calculated with the 1-D MEM as input data, and the principal stresses around the borehole can then be compared to the rock failure criteria to determine whether the borehole wall has failed or not.

Rock failure criteria

Wellbore instability due to rock failure is caused by two major types, tensile failure or shear failure. Shear failure is usually caused by low mud weight while tensile failure is caused by high mud weight. Several methods exist for predicting rock failure (wellbore instability). The most commonly used failure criteria include Mohr coulomb criteria to determine shear failure and maximum tensile stress criteria to determine tensile failure.

![Figure 12: MEM and Wellbore stability analysis of well. X](image)
1. Breakouts (Shear failure) are observed at highlighted depths on dual arm calipers available in 8 ½” section.
2. Failures predicted by model matches well with the calipers
3. 9 5/8” casing shoe could have been landed deeper to get higher frac gradient and a wider mud weight window for 8 ½” section

Figure 13: MEM and Wellbore stability analysis of well. Y

1. Breakouts (Shear failure) are observed as evident from the caliper log
2. Failures predicted by model matches well with the calipers
3. With currently used casing policy mud weight window is ~0.10SG in 8 ½” section.
4. 9 5/8” casing shoe can be pushed deeper (~100m) to get higher frac gradient and a wider mud weight window for 8 ½” section

Figure 14: MEM and Wellbore stability analysis of well. Z

Results of MEM & wellbore stability analysis

Based on the post-drill Geomechanical models of wells X and Y, pre-drill wellbore stability analysis was conducted for reservoir section of well Z (8.5” section) to generate a stable mud weight window. Optimum mud weight and casing policy design were recommended. By following the recommendations, major drilling related risks were not encountered in 8.5” section thus reducing NPT and rig cost. This had not only saved drilling days but also led to huge improvement in the wellbore condition as compared to offset wells X and Y (Fig-15).

Mud weight windows when considered in for the drilled sections indicate that by optimizing current casing plan, significant drill mud weight margins can be achieved. At certain depths in Tirupati and Raghavapuram formation, the mud weight window shifts to higher mud weight range. By setting the 13-3/8” casing and 9-5/8” casing just below these depths will allow increasing drill mud weight in the section below for significantly improving wellbore stability and mitigating risks of loss and kick (Fig. 15).

Apart from drilling optimization, Geomechanics study had also helped in selection of good zones to perforate and fracture. Strike-slip to thrust stress regime is identified in the reservoir section (Nandigama formation). This indicates generation of complex fracture geometry and other challenges arising due to high breakdown. Hence, the stress models can be used to optimize hydraulic fracturing in these reservoirs.

WELL: X
Post drill Geomechanical model

WELL: Y
Post drill Geomechanical model

WELL: Z
Pre drill Geomechanical model

Figure 15: Geomechanical model of wells X, Y & Z

Geomechanical analysis has identified a significant increase in pore pressure in bottom part of Raghavapuram formation thereby narrowing mud weight window in Nandigama formation. This requires proper mud weight design and isolation of different pressure regimes with improvised casing policy. Post-drill Geomechanical analysis was carried out for well X and Y in 12.25” and 8.5” sections utilizing inputs from advanced sonic measurements. The main findings of the post-drill study are:

· Losses caused by ECD’s crossing fracture gradient at 9-5/8” casing shoe
· Rotation of borehole ovalization in the lower zones of Raghavapuram shales indicating rotation of stresses
· Nandigama formation has consistent stress orientation of 110deg to 120deg from North
· Existence of pressure ramp in Raghavapuram shale from 1.32gm/cc upto 1.8gm/cc
· Stress regime change from normal in Raghavapuram formation to strike slip to thrust in Nandigama formation
· Presence of stress barriers inside sand packs in Nandigama formation with 10 to 15% stress anisotropy.
1. Breakouts (Shear failure) are observed as evident from the caliper log
2. Failures predicted by model matches well with the calipers
3. With currently used casing policy mud weight window is ~0.18SG in 8 ½” section.
4. 9 5/8” casing shoe can be pushed deeper (~100m) to get higher frac gradient and a wider mud weight window for 8 ½” section

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Figure 16: Hole shape analysis of wells X, Y & Z

**Conclusions**

- Type-II overpressure was identified from density vs slowness crossplot which can be due to faulting, fluid migration and clay diagenesis. Further identified type-II over pressure is due to clay diagenesis from Fe vs Si and Al vs Si ECS elemental crossplot.

- Rotation of borehole ovalization in the lower zones of Raghavapuram shales indicating rotation of stresses. Nandigama formation has consistent stress orientation of 110deg to 120deg from North.

- Based on the stress analysis, Strike slip (SHmax≥Sv≥Shmin) stress regime was identified In Raghavapuram formation and strike slip (SHmax≥Sv≥Shmin) to thrust regime (SHmax≥Shmin≥Sv) identified in Nandigama formation.

- Based on the post drill Geomechanical study of wells X & Z, Predrill wellbore stability analysis was conducted for 8 1/2” section covering part of Raghavapuram & Nandigama formation. Recommendations from predrill analysis followed and obtained reduces NPT and improvement in the hole condition.

- Based on the MEM & wellbore stability analysis, it is observed that by optimizing current casing policy significant mud weight window margins achieved. By setting 13 3/8” and 9 5/8” casings about 100-150m improves mud weight window margins thus improves well bore stability and mitigating risks of loss and stuck ups.

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Conclusions

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Innovative Technique for Processing and Interpretation of Old Russian Log Data for Petro-physical Evaluation of Complex Lithology Shaly Sand Reservoirs of Cambay Basin

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Abstract

Prior to introduction of Direct Digital Logging (DDL) having full suite of Resistivity-Neutron-Density-GR-SP-Caliper (Triple Combo) logs in early eighties, all old wells have only Russian Log data with limited log suite comprising generally of unfocussed Resistivity-SP-Caliper, very rarely GR and Neutron in counts per second(cps). In Cambay basin, around 1500 out of 7000 drilled wells have Russian log data. Due to complex and heterogeneous nature of reservoirs, geo-cellular modelling (GCM) and reservoir simulation studies are being routinely carried out for enhancement of production of hydrocarbon and developmental of field. To meet these objectives petrophysical evaluation of Russian log data for reservoir parameters such as clay volume, effective porosity and water saturation becomes essential. Due to lack of appropriate methodology and techniques for estimation of reservoir parameters, these wells are used only for geological correlation and left out for property modelling, leading to improper GCM and subsequent reservoir simulation study. In the present study, an innovative technique for processing and interpretation of old Russian log data for petrophysical evaluation of complex lithology shaly sand reservoirs of Kalol field have been developed. From the developed innovative technique, estimation of volume of shale, porosity and water saturation for old Russian wells are carried out. The shale volume is computed from the SP log response developed in shale and clean sand layer. For estimation of porosity in this technique, an empirical relationship has been established using regression analysis of porosity and shale volume in Elan processed recent wells where new generation porosity logs are recorded. Water saturation has been determined using the Indonesian equation with available core derived results have been validated with core and production testing details. The results have been used in property modelling in GCM for final development plan of this giant onshore Kalol field. The developed technique and work flow can also be extended to process and interpret old Russian log data of other basins for realistic petro-physical evaluation and uncertainty reduction in GCM and subsequent reservoir simulation study.

Introduction

Kalol oil field is one of the biggest onshore oil field situated in Cambay rift basin on western margin of Indian platform (Fig-1). It is under exploitation since 1961. The field is located around 20 km NNW of Ahmedabad city in Ahmedabad-Mehsana tectonic block and the most prolific hydrocarbon producer of the basin.

The present study deals with Kalol formation comprising of inter bedded sandstones, siltstones, sideritic, pyritic and carbonaceous shale, and coals deposited in freshwater, intertidal-flat, brackish and shallow marine environments.

These reservoirs of mid-Eocene age are the major hydrocarbon producers in Ahmedabad–Mehesana and Tarapur-Cambay blocks of North Cambay basin. Kalol Formation has been divided into 12 pays from K-I to K-XII from top to bottom with intervening shale and coals. Kalol field of Ahmedabad-Mehesana block is the biggest field of Cambay basin with more than 700 drilled wells out of which 237 wells have Russian log data. The objective of the study was to determine the Petrophysical Characteristics of a Mid Eocene oil
reservoir in kalol field of Ahmedabad-Mehsana block, Cambay Basin. Kalol field of Ahmedabad-Mehesana block is the biggest field of Cambay basin with more than 700 drilled wells out of which 237 wells have Russian log data. The major obstacle for the petrophysicist was that most of the wells only had Russian logs made available for analysis, namely the spontaneous potential (SP) and the Gradient or lateral resistivity. This paucity of data meant that the petrophysicist had to invoke some major assumptions in order to provide a reasonable reservoir characterization and to carry out a Geo-Cellular Modelling (GCM), reservoir simulation studies for better field development and optimum exploitation.

Due to lack of appropriate methodology & techniques for estimation of reservoir parameters, these wells with old Russian logs are used only for geological correlation and left out for property modelling, leading to improper GCM and subsequent reservoir simulation study. In the process, some of the reservoirs are being overlooked from hydrocarbon point of view.

To meet these objectives processing of Russian log data for reservoir parameters such as clay volume, effective porosity and water saturation becomes essential.

Methodology and Workflow

The Petrophysical evaluation of old Russian style logs is generated in Power log software though deterministic module in all 19 wells in the study area.

Methodology and workflow for petrophysical evaluation of shaly sand reservoirs

1. Loading/splicing/merging/depth matching/de-spiking of the available old Russian well logs and nearby recently drilled wells with modern generation porosity logs within the study area.

2. Computation of a 'Pesudo-compensated BKZ'gradient log by averaging the conductivity of available identically spaced 'BKZ' and 'Inverted BKZ' curves.

3. Computation of volume of clay using SP log and another logs, gamma ray (GR) for the old Russia wells.

4. Generation of empirical relationship between volume of clay vs effective porosity for recent wells with modern generation neutron-density and sonic logs.

5. Validation of predicted porosity from empirical relationship with recorded porosity logs or available core derived porosity in wells within the study area.

6. Predication the porosity log for the old Russian wells using the derived empirical relationship.

7. Determination the water saturation using widely used Indonesian equation with available core derived a,m,n and well establishes formation water resistivity for the pay sands.

The developed technique and workflow in the present study uses SP response for estimation of clay volume, effective porosity and water saturation.

The biggest problem with Russian log data is lack of porosity logs and therefore, there is a myth in oil industry that the wells with Russian logs cannot be evaluated using modern day shaly sand interpretation techniques. In wells with neutron logs recorded as counts per second attempts have been made in the past to convert into porosity through interpolation between shale and clean sand neutron counts, but due to statistical nature of these recordings, large amount of error is imperative with these calibrations.

![Figure 1: Location map of Kalol field, Cambay Basin](image-url)
True Formation Resistivity

The old wells with Russian logs frequently have inverted BKZ curves in conjunction with regular lateral of the same spacing with unfocussed and asymmetric nature of resistivity log responses. When suites of resistivity logs do include identically spaced BKZ and inverted BKZ curves a ‘Pseudo-compensated BKZ’ gradient log can be prepared by averaging the conductivity of each of the curves:

\[ R_c = \frac{1}{(0.5 / R1) + (0.5 / R2)} \]  

Where \( R_c \) is the BKZ gradient curve (for instance R_2M) and \( R_c \) is the Inverted BKZ gradient curve (for instance R_2MT) from Lateral tool which gives asymmetric response above and below a bed boundary. The resultant curve is symmetrical, deep reading and usable in digital processing. Comparisons with induction logs, focused laterolog and potential logs justify the use of this pseudo compensated BKZ gradient as for estimation of formation water saturation.

Shale Volume

Spontaneous Potential (SP) log of Russian units is of very good quality due to its recording without electrical power to the down hole assembly and single core cable. SP response is successfully used for estimation of clay volume in these wells using the equation:

\[ (V_{cl})_{sp} = \frac{(SP)_{log} = (sp) \min}{(SP)_{max} - (sp) \min} \]  

However, if SP log is missing or flat due to poor salinity contrast between bore hole and formation, another methods using gamma ray (GR) and deep resistivity has been used and minimum of these at each level was selected as the final value for shale volume.

Effective Porosity

In this step, an empirical relationship between volume of clay and effective porosity for recently drilled nearby wells with modern generation neutron-density and sonic logs, has been generated using regression analysis (figure-2)

\[ \varphi_c = \varphi_{max} \left[ (1 - V_{cl})^{(1.25 + 0.25V_{cl})} \right] \]

Where, \( \varphi_c \) is the maximum porosity in clean sand reservoir. Maximum porosity is estimated from core or from nearby recent wells with Density-Neutron logs against clean sand section.

It is important to note here is that the coal points in regression analysis have been excluded by using the constraint from Density and Neutron log.

The developed technique for effective porosity make the following major assumptions:

1. The maximum porosity occurs in the cleanest sand.
2. The porosity decreases as shaliness increases.
3. The variation in porosity due to other effects is negligible.

Figure 2: Regression analysis of Clay Volume (Vcl) and effective Porosity (PIGN). Plot shows a good relationship between Vcl and PIGN with Correlation coefficient: 0.95
Water saturation

In this final step, the clay volume and effective porosity and equivalent computed in previous steps have been used to compute water salinity (using well known and widely used Indonesian equation (4) with core derived a, m, n parameters, and  of 0.25 ohmm at formation temperature, established for the pay sands.

\[ S_w^{-m/2} = \left[ \left( \frac{R_{clay}}{\sqrt{R_{clay}}} \right) + \left( \frac{\phi^{(m/2)}}{aR_w} \right) \right] \sqrt{R} \]

Where \( R \) is shale resistivity and can be inferred directly from the log.

Discussion of Results

The technique has been successfully applied in data processing of 19 wells covering 10 pay sands of Kalol field to estimate the clay volume, effective porosity and water saturation.

The processing results i.e. clay volume, porosity and water saturation have been validated with core, cutting and production testing details. The results have been used in property modeling in GCM for final development plan. The developed relationships are used for hydrocarbon bearing zones and water bearing zones/shale sections.

Well-X

This well contains the modern generation resistivity and porosity logs. Petrophysical evaluation using the ELAN processing was available for this well. For the validation of the porosity computation using the developed methodology, Effective porosity (PHI_R) is computed using the generated empirical relationship. The results show a good match of porosity (PHI_R) and PIGN and validates the developed porosity and VCL relationship for estimation of porosity for wells with no recorded porosity logs.

Well-Y

This well contains old Russian logs, SP and Resistivity (2M, 2MT and NOR). Petrophysical parameters for this well are computed using the developed methodology/technique. True resistivity (RT) is computed using the lateral resistivity 2M and 2MT logs which shows a good agreement with recorded resistivity, NOR log. Effective porosity is computed using the VCL from SP response and water saturation is computed using Indonesian equation. Computed results (fig-4) are corroborative with production testing results.

Conclusions

The present study has clearly brought out an innovative approach for processing and interpretation of old Russian log data without porosity log available. The technique has been successfully applied in data processing of 19 wells covering 10 pay sands to estimate the clay volume, effective porosity and water saturation. The processing results i.e. clay volume, porosity and water saturation have been validated with core, cutting and production testing details. The results have been used in property modeling in GCM for final development plan of this giant onshore field. The developed technique and workflow can also be extended to process Russian log data of other basins for realistic petro-physical evaluation.

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The views expressed in this paper are solely of the authors and do not necessarily reflect the view of ONGC.
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Figure 3: Well-X, Comparison between Elan processed effective Porosity (PIGN) and computed porosity (PHI_R) by developed empirical relationship (Eq.3)
Figure 3: Well-X, Comparison between Elan processed effective Porosity (PIGN) and computed porosity (PHI_R) by developed empirical relationship (Eq.3)

Figure 4: Well-Y, Composite Log consisting of basic Russian logs (track-1,2 & 3) and processed output by developed technique; Water Saturation & Effective Porosity (track-4) and Volume of Clay (track-5)
Rock Physics Modelling of Unconsolidated Deep Water Shaly Sandstone Reservoir of KG Offshore Basin for Seismic Reservoir Characterization: A Case Study

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Key Words: Rock Physics modelling, Petro-physical evaluation, reservoir characterization, Unconsolidated, Vp/Vs, P-Imp, Shear Wave, seismic inversion

Abstract

Quantitative seismic interpretation plays a major role in reservoir characterization for unlocking the potential and spatial distribution of hydrocarbon bearing geo-bodies. Shear wave velocity is a pre-requisite for prestack inversion and AVO analysis which is available in very few exploratory wells only. Further, recorded shear wave velocity is severely affected by bad borehole condition, mud filtrate invasion and sudden lithological changes. Rock physics creates a link between elastic rock properties (compressional & shear velocities, elastic moduli, poisson ratio etc.), petrophysical properties (primary/secondary porosity, water saturation, clay & mineral volumes) and geological information (reservoir internal structure, cementation, compaction, depositional setting etc.). Therefore, rock physics modelling is used for prediction of elastic wave properties especially shear wave velocity, Vp/Vs ratio and poission ratio in all the wells of area under study.

The most commonly used Xu & White (1995) rock physics model based upon inclusion theory of Kuster & Toksoz(1974), Gassman fluid substitution (1951) and differential effective medium approximation, is suitable for consolidated and low to moderate porosity reservoirs. This model generally does not work well in case of high porosity unconsolidated sand reservoirs. Hertz-Mindlin model based upon grain contact theory has been found better for prediction of shear and compressional wave velocities in unconsolidated reservoirs. During burial or compaction, when sand grains come closer and are bound with cementing material like calcite, clay, quartz or ferrigenous minerals, the contact-cement model is used for estimation of shear velocity.

The present study has brought out that Hertz Mindlin friable sand model based upon grain contact thory works well for prediction of elastic rock properties (Vp, Vs and density) of unconsolidated clean sands with clay volume less than 5%. In reservoirs having clay volume from 5 to 50%, contact cement model has been successfully used with clay as cementing material based upon by core studies. Gassman fluid substitution has been found to be most appropriate due to equilibrium of pore fluid flow induced by elastic wave within half wave period is achieved in these high porosity high permeability unconsolidated reservoirs.

The results of rock physics modeling are validated with recorded Vp&Vs in four wells having sonic scanner data and good bore hole condition with a correlation of 92% between predicted and recorded shear velocities.

The output of rock physics modelling has been successfully used in seismic inversion and AVO analysis for final development plan of KG-DWN-98/2 block in KG Offshore Basin. A very good match between seismic inversion results and the elastic log properties predicted through rock physics modelling in seismic bandwidth proves the efficacy and usefulness of the methodology. The study is further being used for building 3-D Geomechanical Model in the area for safe drilling, completion and production during up-coming final development phase. The study can be extended to nearby blocks in the adjoining areas with similar depositional setting.
Introduction

KGDWN-98/2, NELP-1 block, covers an area of 7294.6 sq km. It is located off the coast of Godavari delta in the east coast of India (Fig. 1). Hydrocarbons have been established by ONGC and other operators in Plio-Pleistocene levels in the basin. It is youngest petroleum system in the basin which belongs to post rift tectonic stage of evolution with hydrocarbons occurring in structurally and/or stratigraphically controlled traps in Pleistocene to Miocene reservoirs. These reservoirs have been deposited under marine conditions and source rock is thought to be Eocene to Oligocene marine shale.

Out of 24 wells drilled in the area, 15 wells are oil and/or gas bearing in Pleistocene sequence. Pay sand thicknesses encountered in the wells varies from 0.5 – 42 m in zone of interest within Pleistocene sequence.

The objective of rock physics modelling was to predict shear wave velocity in all the vertical wells for use in pre-stack seismic inversion and AVO studies. Seismic reservoir characterisation was aimed at pay sand delineation in area through AVO analysis and pre-stack inversion and bring out the most probable lateral and vertical distribution of pay sands encountered in wells drilled in study area.

Further, study was used to fine tune Geo-Cellular Model for reservoir simulation studies to finalise development plan of the area and also being used for building 3-D Geo-mechanical Model in the area for safe drilling, completion and production during up-coming final development phase.

Major challenges in petro-physical evaluation & rock physics modeling unconsolidated nature of reservoir

The sand developed in Pliocene/Pleistocene age in the studied area is unconsolidated in nature as suggested by core studies carried out in some wells. High value of sonic travel time (130-140 µsec/ft) observed in clean sand interval in well-A (Fig.-2) also confirmed the un-consolidated nature of reservoir. The shale underlying and overlying these reservoir intervals also exhibit high value of sonic travel time ranging from 130-170 µsec/ft due to unconsolidated nature of the formations under study. Hence core-log integration confirmed the un-consolidated nature of reservoir. In unconsolidated reservoirs, Vp/Vs ratio is generally more as compared to consolidated reservoir. For example, the well-known Vp/Vs value of 1.6 or below for gas bearing formations may not
Thinly laminated sand shale sequences

The thin sand shale laminations are observed in cores as well as high resolution image logs. The high vertical resolution image log FMI also confirmed that thin sand shale lamination in the reservoir in the well-B in Fig.-3. The RT-Scanner tool which reads both vertical and horizontal resistivity tells about sand shale lamination through anisotropy measurement. The RT-Scanner recorded in some wells also confirms the sand shale laminations in the area under study. Shear wave data is in general affected by rapid lithological changes in a thinly laminated reservoir due to excessive attenuation of refracted shear head wave energy. Rock Physics Modelling through a robust Petro-physics will minimize the effect of laminated nature on predicted shear wave velocity.

Variation in shale / claystone elastic properties

The shale or claystone deposited in the Godavari clay formation is also varying in nature due to compaction disequilibrium due to debris flow and rapid sedimentation as observed on conventional core (Fig.-2) in the form of grain size variation from conglomerates & clay clasts to very fine grained sand. The variation in elastic properties of inter reservoir and intra-reservoir clay hale are observed, both laterally as well as vertically. CMR log, recorded in well-C (Fig.-4) indicates this variability through change in total porosity and hence elastic properties against three shale intervals marked with red rectangles.

High Gamma ray against reservoir: The high gamma ray is observed in the otherwise clean sand reservoir in many studied wells (Fig.-3 &5). The high gamma is attributed to presence of feldspar as confirmed by thin section core analysis in well-D(Table-1)

Grain Size variations: The occurrence of silt sized quartz grains in the reservoir also make the petro-physical evaluation and RPM a challenging task. Presence of silt is inferred shale type separation in N-D logs against porous & permeable reservoirs section indicated by invasion profile in resistivity, low DT & GR values compared to neighboring shale (Table-1).

Bad Borehole condition: Bore hole condition is bad with wash outs and rugosity in 7 out of 19 wells in spite of the use of KCl-polymer mud. However, use of Oil Based Mud (OBM) has improved bore hole condition in 5 wells in the study area.

<table>
<thead>
<tr>
<th>Minerals</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>0.03</td>
<td>-</td>
<td>0.03</td>
<td>-</td>
</tr>
<tr>
<td>Orthoclase</td>
<td>0.04</td>
<td>-</td>
<td>0.02</td>
<td>-</td>
</tr>
<tr>
<td>Silt</td>
<td>-</td>
<td>0.09</td>
<td>-</td>
<td>0.06</td>
</tr>
<tr>
<td>Clay</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.06</td>
</tr>
</tbody>
</table>

Table 1: Mineral Grain Volume Percentages
Petrophysical Evaluation

Comprehensive petrophysical evaluation is a pre-requisite for an effective rock physics modelling. The petrophysical reservoir evaluation was carried out in 19 wells using multimineral processing with GEOLOG software module using core derived a, m and n parameters, salinity based formation water resistivity and Indonesian equation. The output of petrophysical evaluation like mineral volumes, porosity and water saturation was used as input in rock physics modelling. The following methodology and workflow was adopted for Petro-physical evaluation.

Data conditioning: Different log runs of data recorded in all 24 wells were merged and depth matching was done for all the log curves with reference to deep resistivity. The density and sonic log data was conditioned for bad borehole effects and missing data using Multi-Resolution Graphical Clustering (MRGC) technique. De-spiking of log curves was also carried out wherever required. The conditioned data of 24 wells were used in well to seismic tie and geological correlation.

Environmental corrections: Environmental corrections (mud, borehole and invasion correction) were applied on the conditioned log data (GR, Neutron & Resistivity) through PRECAL module of Geolog software.

Formation Water Resistivity and Archie's petrophysical parameters

The Formation water resistivity (Rw) ranging from 0.06 - 0.12 ohm-m at formation temperature has been used based upon produced water salinity data and Picket Plots. Archie’s parameters, a=1, m=1.91 & n=1.66 based upon available petrophysical core studies in well DWN-P-1 and its nearby wells. In other areas, the standard parameters a=0.62, m=2.15 & n=2 were used. Indonesian equation model was used for computation the water saturation.

Selection of Mineral Model: Based on core studies integrated with conventional and high-tech logs, five mineral model (sand, silt, feldspar, pyrite & clay) is selected for comprehensive petrophysical evaluation. Processing parameters for minerals used for multi-min processing are given in table below:

<table>
<thead>
<tr>
<th></th>
<th>Quartz</th>
<th>Orthoclase</th>
<th>Pyrite</th>
<th>Silt</th>
<th>Clay</th>
</tr>
</thead>
<tbody>
<tr>
<td>RHOB</td>
<td>2.65</td>
<td>2.6</td>
<td>4.99</td>
<td>2.6</td>
<td>2.0-2.3</td>
</tr>
<tr>
<td>NPHI</td>
<td>-0.03</td>
<td>-0.04</td>
<td>0</td>
<td>0.3</td>
<td>0.5-0.65</td>
</tr>
<tr>
<td>DT</td>
<td>56</td>
<td>70</td>
<td>37.6</td>
<td>70-85</td>
<td>140-170</td>
</tr>
<tr>
<td>U</td>
<td>5</td>
<td>8.71</td>
<td>82.2</td>
<td>4.8</td>
<td>8.5-10</td>
</tr>
<tr>
<td>GR</td>
<td>50-80</td>
<td>220</td>
<td>5</td>
<td>85-120</td>
<td>100-135</td>
</tr>
</tbody>
</table>

Rock Physics Modelling (RPM)

Rock physics creates a link between elastic rock properties (compressional & shear velocities, elastic moduli, poisson ratio etc.), petro-physical properties (primary/secondary porosity, water saturation, clay & mineral volumes) and local geological information (reservoir internal structure, cementation, compaction, depositional setting etc.). Therefore, rock physics modelling is used for prediction of elastic wave properties especially shear wave velocity, Vp/Vs ratio and poisson ratio in all the wells of area under study.

The most commonly used Xu & White rock physics model is based upon inclusion theory of Kuster & Toksoz, Gassman fluid substitution and differential effective medium approximation, which works well in consolidated and low to moderate porosity reservoirs. This model generally does not give desirable results in case of unconsolidated sand reservoirs. Rock physics modelling carried out earlier in the same area using Xu-White model could not give meaningful interpretation through seismic Inversion/AVO analysis resulting into two dry wells.
In the present study, an attempt was made to predict elastic wave velocities \( V_p \) and \( V_s \) for unconsolidated reservoir using grain contact based models, which works very well in the study area (Avseth et al., 2010). The main objective of the study was selection of appropriate Rock Physics Model (RPM) for unconsolidated reservoirs and check its efficacy in KG-DWN-98/2 by comparing results with log data recorded with sonic scanner tool against good borehole condition. Sonic Scanner tool is a 3-D new generation wireline tool which provides axial, azimuthal and radial information from the 5 transmitters and 104 receivers (13 stations/8 azimuthal receivers at each station). The depth of investigation of this tool is having 2-3 times of borehole diameters, reading beyond altered zone by invading bore hole fluids (Pistre et al., 2005).

Hertz-Mindlin model based upon grain contact theory has been found suitable for prediction of shear and compressional wave velocities in unconsolidated clean sand reservoirs (\( V_c < 5\% \)). Core studies and log features suggested that clay is acting as cementing material in shaly sands as clean sands are much more friable than shaly sands. Therefore, in shaly sand reservoirs (\( 5\% < V_c < 50\% \)), contact-cement model with clay as cementing material at grain contacts is applied for estimation of shear & compressional wave velocities. Formation pressure measured by MDT tool has been used as an input to the contact theory model.

**Methodology and work flow for petrophysical evaluation and rock physics modeling**

- Log data loading/editing/conditioning
- Environmental corrections of log data
- Compute salinity, temperature and pressure logs from recorded BHT, MDT & cross plots, available information of produced water salinity
- Zonation of whole interval as per variability of shale properties
- Selection of mineral model and a,m,n, parameters for petrophysical evaluation based upon available core studies.
- Comprehensive petrophysical evaluation for mineral volumes (Vquartz, Vsilt, Vfeldspar & Vclay), Porosity (Phie, Phit) and water saturation (Sw)
- Computation of volume weighted averaging of dry minerals elastic moduli using Reus bounds.
- Computation of volume weighted averaging of fluids elastic moduli using uniform mixing for oil & patchy for gas zones.
- Estimation of dry framework elastic moduli \( K_{dry}, \rho_{dry} \) using HM & CCM models.
- Fluid substitution (Gassman) for estimation of saturated elastic moduli, \( K_{sat}, \rho_{sat}, V_p, V_s \) and \( \rho_b \).
- Computation of \( V_p/V_s, P-Imp \) and generation of X-plots for seismic reservoir characterisation on inverted \( V_p, V_s, \rho_b, \rho_p, V_p/V_s, P-Imp \) volumes.

Rock Physics modelling with selected models was carried out in all the 19 vertical wells in which petro-physical evaluation was done. Out of 19 studied wells, 4 wells are having sonic scanner data for model building and validation. An excellent match between modelled data and data recorded with Sonic Scanner tool is observed. The results of the study in the form of \( V_p/V_s \) ratio and P-Impedance has been used for zone wise pre-stack seismic inversion and AVO analysis for reservoir characterisation. The results of petrophysical evaluation i.e., effective porosity, water saturation, clay volume & mineral volumes has also been used for fine tuning of Geo-Cellular Modelling for reservoir simulation studies.

**Discussion of Results**

A comparison of recorded and modelled log data on \( V_p/V_s \) vs. P-Impedance cross plot (Fig.-5) indicates the usefulness of appropriate rock physics modelling for prediction of acoustic properties (\( V_p, V_s, \rho_b \)) from petrophysical properties (mineral volumes, porosity & water saturation). A large scatter in recorded data due to bad bore hole is removed.

The results of rock physics modeling in 4 wells having sonic scanner data with good bore hole condition are validated with recorded data and a correlation co-efficient of 91% is achieved, as shown in Fig.-6. Sonic Scanner tool is a new generation wire-line tool which provides axial, azimuthal and radial information from the 5 transmitters and 104 receivers (13 stations/8 azimuthal receivers at each station). The depth of investigation of this tool is 2-3 times of borehole diameters, reading beyond altered zone by invading bore-hole fluids.
The results of petro-physical evaluation and rock physics modelling in well-E are shown in Fig-7&8 with 92% correlation between recorded and predicted Vp/Vs ratio. Vp/Vs ratio in unconsolidated reservoirs in the oil bearing intervals 2100-2120 m, 2138-2168 m is in the range 1.75-2.1. In the bottom reservoir OWC encountered at 2168 m from petrophysical evaluation is well demarcated from Rock Physics Modelling also. There is change in Vp/Vs ratio from 2.1 to 2.4. In rock Physics template used for reservoir characterisation through seismic inversion & AVO analysis clearly demarcates oil, water and shale section on P-Imp vs. Vp/Vs cross plot in this well (Fig.-9).

It is observed that in well-F, water reservoir in deeper depth is masking the oil reservoir at shallower depth level when interpreting as a single interval on Vp/Vs ratio vs. P-impedance cross plots as seen in Fig-10. The presence of hydrocarbons is inferred by zone-wise interpretation of cross plots. This trend is also observed in other wells of the study area. The data suggests that inversion carried out zone wise may give meaning results.

Vp/Vs ratio in shale sections varies from 2.0 to 3.8. Due to vertical variation in consolidation and shale/clay properties an overlap of bottom shale/claystone with upper reservoirs has been observed. In well-G, shale in the bottom interval 2428-2579 m is masking the gas reservoirs in upper intervals 1425-2100 m on cross plots of Vp/Vs and P-Imp (Fig.-11). Therefore, it will be worthwhile to carry out the inversion and AVO analysis zone wise.

Vp/Vs and P-impedance estimated by the present study at well level has been upscaled to seismic bandwidth and used for well to seismic tie and calibration of seismic inversion results in 3D-space (Toki et. Al,2016). An excellent match between representative inverted seismic response at well-E and upscaled log derived Vp/Vs & P-Impedance as shown in Fig.-12, proves the efficacy of the modelling technique and its usefulness in seismic reservoir characterisation.

Conclusions

- A comprehensive petro-physical model addressing mineralogical and textural variations is a pre-requisite for effective rock physics modelling.
- Unconsolidated and laminated nature of reservoirs developed in Godavari clay section of KG DWN-98/2 block and vertical variations of shale/clay-stone elastic properties make rock physics modeling a challenging task.
- Grain contact theory based rock physics models have been applied successfully for prediction of elastic properties (Vp, Vs, density, Vp/Vs, P-imp) in 19 wells across KG-98/2 block.
- Model has been calibrated and validated in 4 wells having sonic scanner data recorded in good borehole condition. The correlation co-efficient of 91% is achieved.
- Vp/Vs ratio in these unconsolidated reservoirs varies for oil reservoir 1.6-2.3, gas reservoir 1.6-2.5, water 1.6-2.5 & shale 2-3.8. Overlap is due to variability in consolidation & shaliness.
- In spite of unconsolidated and laminated nature of the results of Rock Physics Modelling is able to differentiate reservoirs & fluid nature on rock physics templates.
- The study has helped in prediction of shear wave velocity in bad bore hole section and thinly laminated reservoir.
- Due to vertical variation in consolidation and shale/clay properties an overlap of upper hydrocarbon bearing sands with lower water sands and bottom shale/claystone with upper reservoirs has been observed.
- Seismic inversion/AVO analysis carried out zone wise resulted in to more realistic reservoir characterization for pay sand delineation and reservoir modelling.
References


Acknowledgment

The authors are thankful to Director (Exploration), ONGC for granting permission to publish this paper. The authors express their sincere gratitude to Sh. Anil Sood, ED-Hol, GEOPIC, ONGC, Dehradun for giving opportunity to carry out the study and providing all facilities. The authors are highly grateful to Dr. Hari Lal, GGM-Head-INTEG, GEOPIC, ONGC, Dehradun for his continuous encouragement and valuable suggestions during the course of the study. The authors express their sincere gratitude to GM-Basin Manager, KG-PG Basin, Chennai & his team for providing data and all co-operation for the study. The authors are thankful to Sh. Sanjeev Toki, DGM (Geophy), Sh. Suresh Srinivasan, Chief Geologist for critical review and valuable suggestions during the course of study. The authors also express their thanks to geo-scientists of Petro-physics, Special Studies & KG Basin groups of GEOPIC for their involvement directly or indirectly for completion of the present study.

NB. The views expressed in this paper are solely of the authors and do not necessarily reflect the view of ONGC.

Figure 5: Well-A, Usefulness of Rock Physics Modelling in unconsolidated reservoirs with acoustic log data affected by bad bore hole data. Modelled data demarcates hydrocarbon, water and shale sections.
References


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Table 1: Well-D, Mineralogical and grain size/sorting analysis on SWC indicates presence feldspar & silt sized quartz.

Table

<table>
<thead>
<tr>
<th>Mineral</th>
<th>SWC No.</th>
<th>SWC %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feldspar</td>
<td>0.6</td>
<td>0.3</td>
</tr>
<tr>
<td>Silt sized quartz</td>
<td>0.6</td>
<td>0.3</td>
</tr>
<tr>
<td>Opaque</td>
<td>0.6</td>
<td>0.6</td>
</tr>
<tr>
<td>Clay</td>
<td>0.4</td>
<td>0.3</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.6</td>
<td>0.6</td>
</tr>
<tr>
<td>Vp</td>
<td>15.0</td>
<td>12.2</td>
</tr>
<tr>
<td>Vp/Vs</td>
<td>8.4</td>
<td>7.3</td>
</tr>
<tr>
<td>P-Imp</td>
<td>50.3</td>
<td>36.9</td>
</tr>
<tr>
<td>Porosity %</td>
<td>19.1</td>
<td>21.3</td>
</tr>
<tr>
<td>Porosity %</td>
<td>19.1</td>
<td>21.3</td>
</tr>
</tbody>
</table>

Figure 6: Validation of Vp/Vs ratio Predicted through Rock Physics Modelling and Recorded by Sonic Scanner Tool in good borehole in 4 wells.

Figure 7: Well-E, Petro-physical Evaluation & Rock Physics Modelling Results showing Excellent match between Predicted & Recorded Elastic Properties (Vp, VS, Vp/Vs & RHOB)

Figure 8: Well-E, Validation of Vp/Vs ratio Predicted through Rock Physics Modelling and Recorded by Sonic Scanner Tool in good borehole environment.

Figure 9: Well-E, Rock Physics Template for selection of appropriate polygon of Vp/Vs and P-Imp. for Lithology & Fluid Characterization in Seismic Inversion and...
Simultaneous Prospecting for Gas Bearing and Fresh Water Reservoirs in Shallow Formations in Manhera Tibba Field of Jaisalmer Sub-Basin

K. Lakshmi Teja, B.S. Haldia, Dr. T. Chattopadhyay, Meenakshi Kumari, V.L.N. Avadhani, P.P. Deo, CEWELL, ONGC Vadodara

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Abstract

The Bandah and Khuiala formations in Manhera Tibba Field of Jaisalmer basin occur at depths ranging from 200-500m are the prospective formations for hydrocarbon exploration and exploitation along with fresh formation water aquifers towards the top. Ground water exploration especially in drought prone areas in Jaisalmer Basin of Rajasthan is of utmost importance for the noble cause of social welfare. Variations in salinity are observed over a depth interval of 100m in these formations. The exact measurement of salinity is of prime importance in order to have error free estimation of reserves and identification of reservoir layers having potable water. The subsurface wireline logging measurements especially resistivity become more diagnostic to estimate the salinity in this rapidly varying environment as surface resistivity surveys generally used for ground water prospecting become ineffective to assess the formation water salinity.

In this paper, a suitable petrophysical model integrating Petrographic/SEM/XRD studies & X-plots is synthesised along with lab derived petrophysical constants for comprehensive interpretation of Bandah and Khuiala Formations which are mainly Limestone layers. This study also includes integrating different methodologies viz. porosity-resistivity cross plot, Resistivity ratio method, apparent resistivity method and formation water resistivity from SP log for estimation of accurate Formation water salinity and the utilization of these different methodologies converging for this purpose is also demonstrated in the present study. A converged representative salinity from these methods has been deduced for extensive reservoirs of Bandah Formation which is used for comprehensive quantitative interpretation of these reservoirs.

The adopted comprehensive approach has resulted in bringing out new gas bearing layers in few wells along with shallow reservoir layers for exploitation of potable water.

Introduction

Jaisalmer Basin is a part of western Rajasthan shelf, lying to the east of Indus basin. This basin is tectonically divided into several blocks, viz. Kishangarh shelf, Jaisalmer-Mari high/arch, Shahgarh low and Miajalar low. In recent past the Manhera Tibba structure of Jaisalmer-Mari high has become focused from development and exploitation point of view (Fig.1). This structure is having hydrocarbon bearing layers in Lower Goru and Pariwar Formations in Mesozoic and Sanu, Khuiala & Bandah Formations in Tertiary sediments. A total number of twenty wells have been drilled on this structure till date. The stratigraphic succession of the Tertiary formations in the Manhera Tibba field has been described in (Fig 2). The Manhera Tibba structure has been successfully delineated by ONGC from hydrocarbon point of view in the shallower Bandah and Khuiala formations and the reservoir layers developed in this formation were taken up for a comprehensive interpretation to augment the potential of these shallow layers from hydrocarbon point of view.

In the present study the Deeper groundwater assessment through wireline logging technology has also been discussed in these drought prone areas of Rajasthan. There are several methods of ground water exploration some of which are aerial and others are surface/sub surface in nature. Aerial methods use remote sensing, satellite images, aerial photography and electromagnetic survey. Surface methods are geological, geomorphical hydrogeological, geophysical and geochemical in nature. The sub-surface methods include geological, tracer techniques and geophysical logging techniques. In drought prone areas of Rajasthan the shallow aquifers are saline and the better option is to draw water from the deeper sources that are found to be potable. Such exploration for deeper groundwater exploitation has already been established successfully in Libya.

Figure 10: Well-F, Water reservoir of interval-2 is masking the Oil reservoir when interpreting in a single interval. VP/VS in oil reservoir: 1.8-2.1, VP/VS in water reservoir: 1.95-2.3. Data suggest that inversion carried out zone wise may give meaningful result.

Figure 12: Representative inverted section of P-impedance and Vp/Vs passing through well E. Good match is seen between inverted results and respective well log filtered in seismic bandwidth.
Simultaneous Prospecting for Gas Bearing and Fresh Water Reservoirs in Shallow Formations in Manhera Tibba Field of Jaisalmer Sub-Basin

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In this paper, a suitable petrophysical model integrating Petrographic/SEM/XRD studies & X-plots is synthesised along with lab derived petrophysical constants for comprehensive interpretation of Bandah and Khuiala Formations which are mainly Limestone layers. This study also includes integrating different methodologies viz. porosity-resistivity cross plot, Resistivity ratio method, apparent resistivity method and formation water resistivity from SP log for estimation of accurate Formation water salinity and the utilization of these different methodologies converging for this purpose is also demonstrated in the present study. A converged representative salinity from these methods has been deduced for extensive reservoirs of Bandah Formation which is used for comprehensive quantitative interpretation of these reservoirs.

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The present study focusses on the shallow reservoir layers of Bandah and Khuiala formations in Jaisalmer Basin which is a part of Rajasthan shelf and is lying to the east of Indus basin. Different methods involving comprehensive log suites have been taken up to determine the salinity accurately. The gas bearing layers of these shallow formations have been interpreted with a unified multi-mineral model. In due course, water bearing layers within shallower depths of these formations have also been identified in this field as a prospective candidates for fresh water exploitation.

**Methodology**

Suitable petrophysical model, using Petrographic/SEM/XRD studies from labs combining with crossplot inferences along with a saturation model synthesized using lab derived petrophysical constants and Pickett plots, has been prepared. The mineralogy used in interpretation also consists of minerals as inferred from SEM/petrographic studies.

The processing of log data for Khuiala & Bandah formations has been carried out using a mineralogical model consisting of calcite as dominant rock forming mineral & Glauconite and the presence of Illite and Kaolinite as clay minerals as reported in core studies (Fig.3). In these formations water and gas are introduced as fluids in the petrophysical model. Dual water model is used for computation of water saturation for taking care of wide variations in Formation water salinity.

Petrophysical parameters a, m & n are crucial constants used in the saturation equation for computing water saturation from the log data. Due to the unavailability of any core study on the core samples in the representative formations of Bandah and Khuiala formations, standard petrophysical constants i.e. m=2, n=2 & a=1 is used. The main pays of Manhera Tibba field interpreted in Bandah (B2) and Khuiala (B4 and C2-C4) are basically limestone reservoirs in nature and are interpreted with the developed petrophysical model.

Correlation profiles were prepared to explain the hydrocarbon occurrences vis-a-vis log characters and interpreted reservoir parameters.

During the course of this study an approach has been adopted for accurate determination of formation water resistivity/salinity in the shallow formations of Jaisalmer sub-Basin with different methodologies. There are four general techniques for evaluation of resistivity of formation water from well logs. After having done that, the formation water salinity is computed from Rw-Salinity chart. These methods are as follows:

- **Porosity resistivity crossplots**: Resistivity values from Rt and a porosity log in the zone of interest are plotted to obtain Rw. This comes handy if the formation has uniform lithology with good hole condition and negligible gas effect on porosity log.

- **Resistivity Ratio Method**: This has the advantage of being independent of porosity. From Archie’s saturation equation we can derive an expression of water saturation as a function of resistivity of the invaded zone to that of the unflushed zone.
  \[ S_w = (R_w / R_m)^{(R_t / R_m)}^{\frac{1}{a}} \]
  where \( R_m \) is the resistivity of mud filtrate and \( R_w \) is the resistivity of the flushed zone. This method gives good results if the formation is clean, \( R_m \) is constant and borehole is good.

- **Rw from SP**: Reading the SSP value from the SP curve. SSP is the deflection of SP curve from the shale baseline. Rw is then determined from the given relation: SSP = - K log \( R_w / R_m \). where K is a temperature related constant.

- **R_w method**: \( R_w \) is defined as \( R_{water} / F \) where F is the formation factor derived from quick look porosity method.

However, in this study, efforts have been made to compute salinity in terms of NaCl concentration by determining the resistivity of formation water at formation temperature using SP log and Pickett plots have also been generated for computation of formation water resistivity. In some wells where DLL-MSFL log have been recorded and hole condition is good Resistivity ratio method has been also adopted (Fig.5).

Collected salinity data of produced water from WCR/FER and other reports is also used for computation of formation water resistivity for different formations (Table-1).
A converged representative salinity from these methods has been deduced for the widely extensive reservoirs of Bandah Formation.

Discussion

- The subsurface formations depict rapidly varying formation water salinities within a short span of 100m of depth interval. This is clearly reflected on resistivity log responses. The Pickett plots made in this interval compute the formation water salinity variation as 5-12 gpl between upper part and lower parts. Hence accurate salinity profiling is of utmost importance to calculate representative water salinity and accurate water saturation.
- One of the shallow layers produced water of salinity 3.8 gpl in the A4 layer of Bandah formation of Manhera Tibba Field. The Resistivity ratio method yielded a formation water resistivity value of around 1.3 ohm-meter giving a salinity value of 3 gpl, while the Pickett plot indicates the Rw value to be around 0.85 ohm-meter giving a salinity of 5 gpl which appears to be the upper limit of salinity (Fig.4).
- The gas bearing and fresh water bearing layers within Bandah Formation are vividly distinguishable with the generated Rxo/RT log where the Rxo/RT log is nearing the value 1 against the water bearing layers (Fig.5).
- The comprehensive interpretation along with the salinity profiling indicates fresh water layers above gas bearing layers. These layers have similar resistivity as that of the gas bearing layers and have wide dispersal. These layers on testing gave fresh water of salinity 3.8 gpl.
- The thin limestone layers developed between B4 and C2-C4 reservoir of Khuiala formation have been interpreted as hydrocarbon bearing from the present study. In one of the wells (MT-10) these layers have been tested and produced gas.
- The comprehensive evaluation has brought out new correlatable shallow gas bearing layers within Khuiala Formation apart from the known hydrocarbon bearing layers (Fig.6).
- The upper limestone layers within Bandah Formation are interpreted to be fresh water bearing with water salinity as 4 gpl (Fig.7).
- It has been inferred from the study that the prospective areas for future development from hydrocarbon point of view lie to the eastern part of Manhera Tibba field while the upper reservoirs of Bandah Formation can be exploited for potable water.

Conclusions

- The accurate formation evaluation methodology adopted in this study has brought out new prospective zones, areas from hydrocarbon point of view.
- Simultaneously fresh water bearing layers have also been enumerated for potable water exploitation.

Acknowledgments

The authors would like to thank ONGC management for giving permission to publish this paper.

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3. SEM analysis of nineteen selected samples from wells namely CT-1, CHT#2, CHT#3, MT#10A and MT#16, MT#17.
4. Effect of Glaucnite on petrophysical properties as revealed by core analysis, W. H. Thomas et al., International symposium of the society of core analyst.
Figure 1: Location map of Manhera Tibba

<table>
<thead>
<tr>
<th>Eon/Era</th>
<th>Period/Epoch</th>
<th>Formation</th>
<th>Reservoir Facies</th>
<th>Lithology</th>
<th>Depositional Environment</th>
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<td>Quaternary</td>
<td>Holocene</td>
<td>Wind-blown Sand/Alluvium</td>
<td>Loose sand and alluvial materials</td>
<td>Aeolian/Alluvial</td>
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<tr>
<td></td>
<td></td>
<td>Holocene to Pleistocene</td>
<td>Shumar</td>
<td>Dune sands, gravels With ferruginous nodules</td>
<td>Fluvial/Lacustrine/Aeolian.</td>
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<td>Tertiary</td>
<td>Middle Eocene</td>
<td>Bandah</td>
<td>A4 &amp; B2 Limestones</td>
<td>Foraminiferal limestone Clayey at the base</td>
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<td></td>
<td>Paleocene</td>
<td>Saru</td>
<td>D3 sandstone &amp; D4 Limestone</td>
<td>Friable sandstone with minor clays</td>
</tr>
</tbody>
</table>

Figure 2: Stratigraphic succession of the Tertiary formations in Manhera Tibba field
Figure 1: Location map of Manhera Tibba

Figure 2: Stratigraphic succession of the Tertiary formations in Manhera Tibba field

Figure 3: SEM image illustrates micro morphology of calcareous claystone

Figure 4: Formation water resistivity estimation from Resistivity-Porosity Cross plot
Figure 5: Formation water resistivity estimation from Resistivity ratio method and Resistivity ratio identifies water and gas bearing layers.

Figure 6: New Hydrocarbon layers identified in between B4 and C2-C4 reservoirs in Manhera Tibba wells.
Table 1

<table>
<thead>
<tr>
<th>Formation/Reservoir</th>
<th>Well No.</th>
<th>Interval (m)</th>
<th>Salinity (gpl)</th>
<th>Rw @ Formation Temp</th>
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<td>MT-9</td>
<td>227-236</td>
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<td>Water surface</td>
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<tr>
<td></td>
<td>MT-7</td>
<td>237.5-250</td>
<td>3.80</td>
<td>1.00 ohm-m @ 105°F</td>
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<td></td>
<td>MT-9</td>
<td>291.5-298</td>
<td>6.44</td>
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<td>MT-1</td>
<td>227-238</td>
<td>4.00</td>
<td>0.8 ohm-m @ 105°F</td>
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<td>Khuiala C2-C4</td>
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<td>327-333</td>
<td>3.00</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td>MT-7</td>
<td>345-358</td>
<td>5.12</td>
<td>0.65 ohm-m @ 105°F</td>
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</table>

Figure 7: A4 reservoir of Bandah formation is interpreted as water.
Addressing Well Integrity Issues with Production Logging: Rejuvenation of Sick wells

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Summary

The productive life of a well can be affected by deterioration of the well integrity which can be due to casing/tubing corrosion, casing damage during drilling/ work over, packer failure, plug failures, cement integrity issues etc.

Severe integrity failures can lead to drop in production/injection, production of undesirable fluids, unwanted/uncontrolled pressure buildup posing a threat to overall safety of the well.

Wells suffering from isolation failures due to cement/casing integrity issues can cause water to channel out in the wellbore, hampering the hydrocarbon production from the main reservoir and sickening the production performance of the well.

Remedial measures can be executed if the nature of problem is diagnosed. One can receive early warning of a potential problem and obtain data for determining a specific restoration program by running well integrity diagnostic tools. There are various well integrity tools available to cater evaluation needs with different working principles and targeting different well integrity problems such as casing/tubing and cement integrity. However in challenging situation and complex environments, the tools may not provide complete diagnostics.

Water cut management has always been a challenging task. Increase in water cut substantially affects the production besides creating environmental issues in handling/disposing the produced water. High water cut acts as a catalyst for further deterioration of well casing/tubing integrity. In extreme cases, water cut reaches a critical value and load the completion string with water due to which the production ceases.

To plan an effective water shut-off (WSO) job, locating source of water is a pre-requisite and production logging is an ideal diagnostic tool for evaluating the source of water production. Production logging can be an effective tool in such scenarios by mapping the flow behaviour in the wellbore and can provide a better idea of the wellbore problems.

The present paper contains two case studies from mature fields in Western Offshore where in production logging helped in identification of well integrity issues and paved the way for complete revival of a producer and an injector well.

Introduction

Production logging plays a pivotal role to exactly diagnose the problems in the well and plan a proper workover/ remedial solution to enhance the well production. Conventional Production Logging Sensors like temperature, pressure, fluid density (gradio), and spinner are usually deployed and if situation warrants, Water Flow Logs are also recorded to address well integrity issues.

Water flow mode of Pulsed Neutron Log, works on the principle of oxygen activation of flowing water slug. Quantitative velocity measurements along with direction of slug movement helps in the identification of damaged parts of the pipe and possible thief zones. A stationary measurement is done by parking the tool and keeping it centralized to the wellbore. The nominal velocity detection range for WFL is 20-300 ft/min.
The following presents two such unique case studies where PLT helped in identifying distinctive well issues in the wells which directed the wells towards proper remedial.

**Case Studies**

**Well “Ä”**

The well “Ä” is a development well which was drilled in the year 2014 (max angle ~ 27º) and completed in the interval X345-X349m and X362-X368m to exploit gas from the reservoir ABC. During initial testing it produced gas @ 1,67,000 SCMD with FTHP of 2348psi. Later after acid job Gas rate increased to 2,20,000 SCMD but later on well had frequent water loading problem and required frequent activation / stimulation. The well has good reservoir zones as identified on the Open Hole logs, hence to diagnose the reason for water production, PLT was planned in the well in 2015. The well was producing 1,00,000 SCMD of gas at an FTHP of 1181psi during that time. Annulus pressure build-up was also observed in the well suggesting integrity issue with packer/tubing.

In order to diagnose and locate the source of water and reasons for annulus pressure build up, Production Logging job was planned with conventional sensors along-with a combination of electrical and optical probes.

From the production logging data, tubing shoe was observed to be around 24.3 m shallower than reported. Also a completion element with internal diameter profile as tubing was observed in the deeper logging interval.

Hence it was concluded that the PBR packer assembly had fallen after separation from the tubing resulting in annulus pressure buildup. (Fig.1).

![Figure 1: Shut in PLT sensors data indicating falling of PBR packer assembly from the tubing in well](image-url)
Production Log data confirmed water entry from the bottom of the log interval and further suggested possible water entry by the channeling of water and entering the well bore from the lowermost perforated interval X362-X368m. As the detached and subsequently fallen down completion element (with top at X358m) has covered the bottom perforations, the precise depth of hydrocarbon/water entry could not be determined. Processing of the data revealed that bottom perforations are producing 1,35,000 SCMD of gas and 92 BPD of condensate and whereas top perforated interval was contributing 6697 SCMD of gas and traces of condensate. Water production of 1917 BPD was observed from the bottom of the log interval and bottom perforated interval.

Based on the Production logging results, the well was taken for rig workover and PBR packer was fished out. Cement squeeze job was carried out further and the well was cleared till X383 m. The well was re-perforated across the interval X345-X349m and X362-X365.5m. The well was recompleted with 4.5” tubing and packer completion.

After the job, well started producing 1,50,000 m³/d of gas with 0% water cut whereas, before WSO it was producing 1,00,000 m³/d of gas with 1900 BPD of water. Thus the intervention resulted in production enhancement by 50% and reduction in water cut by 100%.

**Well “B”**

Well “B” an injector having deviation of 51.25 degrees and completed in the interval X056-X068m, faced annulus pressure build up problem during water injection. The well was completed with 3-1/2” tubing and 9-5/8” casing.

In order to diagnose the problem, a Production Logging survey was done in May 2012, in two different runs. Production Logging was done in Run-1 as per following sequence:

1. Annulus was kept shut and injection was done in tubing while recording production log.
2. Annulus was bled-off while recording PLT and few WFL stations near the packer.

Injection Flow rate quantification showed that amount of water flowing near tubing shoe was same as that flowing inside casing which suggested that water was not flowing upward via any packer leak.
When Annulus was shut, it was found that bottom 2.0 m (X066.0–X068.0 m) of the perforation (X056.0–X068.0 m) is taking 4049 BWPD. After annulus pressure was bled off, it was found that 2.0 m (X066.0–X068.0 m) of the perforation (X056.0–X068.0 m) is taking 3864 BWPD. (Fig-3) The difference of 185 BWPD in the two injection runs is because of 21 psi difference in injection pressure. Further, even temperature response in these cases could not provide any clue of tubing leak. So, the cause of annulus pressure build-up could not be evaluated.

**Injection WFL & PLT Observations**

![Diagram](image)

**Figure 3: Production Logging Results**

Well "B" an injector having deviation of 51.25 degrees and completed in the interval X056-X068 m, faced annulus pressure build-up problem during water injection. The well was completed with 3-1/2" tubing and 9-5/8" casing.

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In order to further investigate the reason behind annulus pressure build up, Run-2 campaign of Production Logging along with Water Flow survey was designed as per the following recording sequence:

1. PLT survey from surface till bottom while injecting water through tubing and bleeding off annulus pressure.
2. PLT survey from surface till bottom while injecting water through annulus and producing from tubing.
3. RST WFL survey from bottom of the well till surface.

When annulus was bled-off and water was injected in tubing, similar spinner changes were observed. (Fig-4)

---

**Figure 4:** Injection through tubing and annulus Bleed-off
When injection was carried out through annulus and production taken from tubing, tubing leaks were detected at several depths both by spinner and WFL stations. (Fig-5)

Figure 5: Water Flow Survey and spinner response during injection of water through annulus-showing tubing leaks
Annulus Injection – WFL Stations Summary

<table>
<thead>
<tr>
<th>Sl. No.</th>
<th>Depth (m)</th>
<th>Water Velocity (ft/min)</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>X 069</td>
<td>0.0</td>
</tr>
<tr>
<td>2</td>
<td>X 029</td>
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<td>X 029</td>
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</tr>
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<td>5</td>
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<td>6</td>
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</tr>
<tr>
<td>21</td>
<td>X 40</td>
<td>16.1</td>
</tr>
</tbody>
</table>

Figure 6: Summary of WFL

Positive spinner changes were observed inside tubing at several depths, indicating entry of water through suspected tubing leaks (Fig-5).

Summary of WFL stations in Fig-6, indicates that at a depth of X820m and below there is no movement of water inside the tubing i.e. there is no leakage in the tubing and above that- velocity of water moving up increases as more water is entering the tubing through leakage points at depths where there is an abrupt increase in velocity.

Thus WFL measurements, validated the findings of spinner that at several places, water which is injected through the annulus of tubing and casing is entering the well bore through tubing leak points.

Subsequently, in February 2013 during workover job old tubings were replaced with new 13 Cr, 3 1/2” FOX tubings and only after that the problem of annulus pressure build up could be successfully rectified.

Conclusions and way forward

These cases establish Production Logging as an effective diagnostic tool and pre-requisite for effective workover operations.

In case major workover requiring cement/completion repair is needed, the operations can be carried out on rig to enhance the productions and revive sick wells.

When increasing trend in water cut or annulus pressure build is observed in a well, recording of Production Logs are recommended to locate the source of the problem. It may not be of much use to acquire Production Log Data, once the well is fully loaded with water & ceases to flow or the pressure in the annulus increases to a threatening level. Consequently, in such cases, well activation or control respectively will be required before attempting PLT logs to locate the source. Regular production logging in such wells can provide a concrete and systematic system to carry out planned workover.

Acknowledgements

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Lean Process to Optimize the Formation Testing Operations in Giant Offshore Oil Field in India

Sunil Choudhary, K. V. Sarma- ONGC, Vaibhav Deshpande, Arvind Kumar, Ankit Kumar, Siddhartha Nahar – Schlumberger, Mumbai India (Vdeshpande@slb.com)

Abstract

Formation Testing is considered one of the most essential services for B & S asset team to characterize the D1 field. Nevertheless, the rig time spent on the log acquisition has always been exerting enormous pressure on the assets and operations team. In order to optimize the operations, a study team was generated between ONGC and SLB in June 2015 to evaluate the previous jobs and come up with recommendations for future operations (Lean process).

The shared team completed their analysis and came up with some technical recommendations which were further applied in next 2 wells and as expected it had a big impact on reducing the time spent on formation testing logging by almost 40%.

Background

Production from the western offshore fields of Oil and Natural Gas Corp. Ltd (ONGC) has a jump of 12% from last year's 285,000 bpd and the highest since January 2010. The jump in current production has mainly come from the NBP field in Bassein and a few marginal fields in the western offshore area. Currently NBP Field contributes 10% of the western offshore productions.

In 2014 two offshore rigs were dedicated to drill appraisal and developments wells in NBP field. Its high production contribution and the need for accelerated oil production increase makes all the operations in NBP field under close monitoring in terms of the time spent/operation.

From the operations point of view optimizing the logging operations was one of the key area because logging was consuming almost 10% of the well operation which is much higher as compare to other fields in the area.

NBP field is located about 80 km southwest of Mumbai high field in deep continental shelf at a water depth of about 90 m. The field was discovered in 1976 with the first well drilled to the depth of 3245 m. Subsequent drilling of exploratory wells confirmed the oil accumulation in Ratnagiri limestone. The early-middle Miocene carbonates belonging to Ratnagiri formation constitute the main reservoir.

The Multi layered complex carbonate reservoir consisting of alternate porous and tight limestone layers. The oil pools developed within the Ratnagiri formation have been grouped into three pays, upper pay, lower pay and low pay. The main porosity type is from vugs, mulds and channels.

Being a heterogeneous carbonate reservoir increased the importance for advanced logging services and made it all the more critical to run MDT in every well in order to validate any preliminary observations of hydrocarbon presence.
Known technical challenges

Based on previous experience, following technical challenges has been identified before starting the study.

1. Heterogeneous reservoir with a mix of good and bad formation mobility.
2. Deep invasion, pumping high volume is required to see Formation fluid.

Formation mobility plays a key role in the formation testing optimization process. It is important to map the mobilities across the formation, so that sampling could be carried out at highest mobility zone, requiring much lesser operational time. One more phenomenon, that affects formation testing sampling operations, is cleaning of the mud filtrate to reach formation fluid. This again would be function of mobilities. It is observed that lower mobility formations take much longer time to clean up filtrate than higher mobility formations. So it is important that operator and service provider develops knowledge about their particular formation with time and experience, and optimizes formation testing (FT) time with each job. So such studies become all the more challenging and important, dealing with heterogeneous carbonate reservoirs.

Workflow

Workflow adopted for optimizing FT operations, consisted of following steps:

1. Data Gathering and QC
2. Statistical Analysis
3. Identify key challenges
4. Craft formation specific solutions
5. Implementation and Feedback for improvement

Process started with collecting the pretest and sampling data from different wells logged in D-1 field. Total of 17 wells were identified, where more than 110 sampling points and about 200 pressure test stations were available for analysis.

These station data were evaluated based on 30 critical parameters like mud type, layer wise mobilities, pretest station time, sampling station time, Formation fluid breakthrough, hydrocarbon type, pumping rate, Total rig time, Fluid identification vs actual sampling time, probe types, pump types etc.

Figure 1: Break up of Time spent on Typical FT operation in D-1

All these parameters were tabulated and plotted so as to derive a pointed conclusion towards potential area of improvement.
Discussion

Based on the data analysis, the study team concluded three areas for optimization:

1. Proper Inlet selection: Based on MDT history, it is noticed that more than 2/3rd number of stations were low mobility and probe operations should not be preferred, rather large area inlet has to be used.

![Figure 2: Success ratio of Fluid identification & sampling stations with Probe Inlet tools](image)

1. As displayed in figures above, 70% of the depths encountered in D1 field are seen to be less than 5 mD/cP.

2. Optimizing the number of stations. Advanced OH formation Evaluation and Gradient analysis been proposed to optimize the number of fluid identification stations.

3. Optimizing the time/station: for that point following has been highlighted: Invasion estimation from resistivity measurement integrated with the pump out information has been used to set a cut off for each layer.

4. Deployment: To avoid any operational complication, depending on angle of wells, Tough logging conveyance option is found suitable

![Figure 3: Number of Stations per Well](image)
Recommendations

Based on the analysis, following recommendations were made for optimizing number of stations:

1. Gradient analysis can be used to reduce number of stations
2. Switch to Larger area inlet like packer based modules instead of Probe inlets
3. Pre job Planning and Proper Mud type selection
4. Use of advanced petrophysical logs to characterize low resistivity pays/heterogeneous formations

Conclusions

Based on this study, recommendations were implemented in the field for next two wells formation testing operations. The packer type inlet showed the highest success rate followed by the focused probe type inlet. The success rate with the conventional probe was the least among all the inlet types. Optimum pumping time and volume were established for each layer. It was observed that packer inlet and focused probe inlet took about 40% and 22% less time respectively as compared to the conventional probe. This helped in saving 3 days of rig time per well using the study recommendations.
Recommendations

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Acknowledgements

The authors would like to acknowledge ONGC, 11 High Team and Bassein & Satellite Asset Team for their kind co-operation and support during the entire study and operations phase of this work.

Figure 5: Inlet Type Vs Success Rate for Sampling

Figure 6: Optimum Time per station Vs Inlet Type
Integration of Inversion of Open Hole Logs with Surface Geological Studies for the Inferences of Provenance of Sediments in North East Coast, Mahanadi Basin, India

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Abstract

Understanding of the source of sediments is critical for defining reservoir quality for future exploration. Surface geological studies for the inferences of the provenance of sediments are generally based on concentrations of different types of clay ratios and other mineralogical assemblages present in the formations deposited by different river systems. XRD studies on cores, SWC samples are discrete samples and are not available continuously. Core calibrated concentrations of different types of clays derived from inversion of open hole logs provides excellent means for the integration to infer the provenance of sediments derived from different river systems in a basin.

Inversion of open hole logs is performed by weighted least square technique by minimization of the objective function, i.e., summation of square of errors between the measured and constructed logs. Theoretically same value of objective function can be achieved with infinite number of combinations of input / output parameters, even with uniquely determined system of equations. Imposition of geological and geophysical constraints on the solutions brings it to a finite set but still too large to fix it for a unique set of inversion parameters. Further, imposition of constraints from core measurements viz. different types of clays, porosity, mineral volumes and grain density makes the inversion results unique and more realistic in a particular geological setting.

The present study is concentrated in wells which are located in the southern part of NEC block of Mahanadi-NEC basin. In these wells the main sediments are constrained within submarine channel-levee complexes of Miocene section derived from Mahanadi river system. Towards the eastern side in the block, thick pile of Neogene sediments occur that have been fed by the Ganges - Brahmaputra river system. In between the sequence of sediments from both river systems overlay on each other.

Inversion of open hole logs is carried out near two separate clusters of wells namely, X1-X2 and Y1. XRD analysis shows X1-X2 wells with mineralogical assemblage of quartz & plagioclase as framework minerals & illite, chlorite & kaolinite as the clay minerals. XRD data in Y1 well shows that the plagioclase percentage is more as compared to X1-X2 wells in the framework minerals and kaolinite & illite-smectite mixed layer clays are dominant clay minerals. The two mineralogical models are used for inversion of open hole logs for the wells drilled in both the clusters.

Clay content analysis of Ganges and Mahanadi surface samples showed that there is distinct variation in Chlorite-Illite ratio as well as Kaolinite- Smectite ratio in both the feeder systems. Ganges sediments show higher chlorite whereas Mahanadi sediments show higher Kaolinite.

This relationship has been integrated with multi-mineral output of inversion results and it was found that sediments around Y1 cluster are derived from Mahanadi system whereas the sediments from X1-X2 cluster are derived from feeder system from both Ganges & Mahanadi area.

This understanding is critical for assessing reservoir quality to be explored in future.
Introduction

In exploration for hydrocarbons, provenance analysis i.e., analyzing the origin of sediments is often critical for understanding reservoir quality. Heavy mineral assemblages are sensitive indicators of sediment provenance and are extensively used for this purpose. Clay fraction analysis is another useful technique which can be utilized for differentiating different sediment sources. Modern riverbed grab samples are studied for their heavy mineral assemblages as well the clay fraction through X-ray diffraction (XRD) method. The results are then compared with similar analysis of the target reservoir sands.

For the analysis of reservoir sands generally conventional cores, Side Wall Cores (SWC) and cutting samples are used. However these samples are discrete and are not available continuously over entire reservoir section. Core calibrated concentrations of different types of framework and clay minerals derived from inversion of open hole logs provide excellent means for the integration with XRD analysis of river bed samples to infer the provenance of sediments in a basin.

Inversion of open hole logs

Mathematically, a log response, $L_i$, represents the volumetric average property of the constituents of the formation measured by the particular logging tool. Quantification of fractions of different rock components and porosity is performed through the inversion of available log suites. Volume fractions, $V_j$ of the constituents defined by specific response parameter on each log measurement are represented by simultaneous log response equations on matrix notation

$$R_{ij} * V_j = L_i$$

Where, $R_{ij} =$ Log Response matrix of $i^{th}$ log measurement of $j^{th}$ mineral component  
$V_j =$ Volume fraction of $j^{th}$ mineral component  
$L_i =$ $i^{th}$ log measurement

These equations are simplest representation of the simultaneous linear tool response equations where fluid is being treated as a rock constituent. Computation of log responses ($L_i$) by using above equation is known as forward modeling and solving the equation for volumetric ($V_j$) is known as inverse modeling or inversion of open hole logs.

At first glance this linear system of equations appear to be very simple for solving unknown volume fraction of the constituent defined by specific response parameter on each log measurement. Any deterministic approach for solving these equations is difficult as:

- All the log measurements inherit statistical uncertainty / background with them.
- Formations in nature cannot be modeled with limited number of constituents and limited number of measurements.
- Response parameters are not perfectly defined for each constituent.
- Even existence of inverse of Response matrix $R_{ij}$, ensured beforehand, may not ensure positive values for the solutions, $V_j$.

These system of equations are solved through statistical approach by minimizing summation of squares errors or incoherence function f between measured and constructed logs by incorporating the uncertainties on measurements, generally known as weighted least square minimization technique:

$$f = \sum (R_{ij} * V_j - L_i)^2 / s_i^2$$

Where $n =$ number of log measurements and $s_i =$ uncertainty on $i^{th}$ logging tool.
Dual fluid system i.e., presence of hydrocarbon, in addition to water, further complicates the situation and linear system of equations becomes non-linear due to inclusion of resistivity logs viz.

\[
\begin{align*}
\Phi \{ mf_r^* S_{xw} + rh^* (1 - S_{xo}) \} + R_{mf}^* V_{z} &= L, \\
\{ V_{o} \} &\left( 1 - (m/2) / \sqrt{a_{Rmf}} \right) * V_{sw}^{n/2} = 1/ \sqrt{R_{xo}} \\
\{ V_{cl} \} &\left( 1 - (m/2) / \sqrt{a_{Rmf}} \right) * V_{sw}^{n/2} = 1/ \sqrt{R_{xo}}
\end{align*}
\]

Where fluid components are excluded from constituents

\( V_r, Rmf \) and \( rh \) represent the log responses of mud filtrate and hydrocarbon respectively.

\( V_{cl} \) and \( \Phi \) denote clay volume and porosity respectively.

All other parameters have usual meanings in Petrophysics.

Straight forward solution of the stated problem through statistical least square approach is to partially differentiate with respect to the unknowns and solve the resulting simultaneous equations namely “Normal equations”. Constraints can be taken into consideration through Lagrange multipliers technique. When the tool response equations are linear / non-linear, resulting normal equations will be linear / non-linear. To solve the nonlinear equations, some iterative scheme is the only solution to the problem. In such cases, mathematical programming technique is the best and efficient method. Before looking for mathematical programming techniques following conditions must be satisfied:

- Objective function \( f \) should be convex as mathematical programming techniques are applicable to only convex functions.
- Hessian Matrix i.e. Matrix of second derivatives should be semi definite and positive.
- Mathematical programming technique selected should ensure the convergence at a global minimum.
- If log responses of the different constituents are defined as vertices of a multidimensional polygon defined by the number of log measurements, it ensures the existence of the inverse of response matrix of \( R_{ij} \) as well as the existence of mathematically feasible solution \( V_{ij} \).
- It also ensures Hessian matrix, in case of formation evaluation problem, is positive and semi definite. One interesting point is that it becomes independent of unknowns. So, several relative minima exist and we have to select only global one i.e., best solution.

Minimization of objective function in least square sense is usually performed by solving first partial derivative matrix equations i.e. JACOBIAN with the condition that second derivative matrix i.e., HESSIAN is positive, using standard non-linear programming technique.

Global minimum for objective function, \( f \), is ensured only for a particular combination of input \( R_{ij} \) and output parameters \( V_{ij} \). However, theoretically, same value of objective function can be achieved with infinite number of combinations of input / output parameters, i.e., \( R_{ij} \) and \( V_{ij} \) even with uniquely determined system of equations i.e. equal number of unknowns and equations. While high incoherence function, \( f \), indicates that model does not fit the data, a low does not verify that the model is correct. For example, different models may fit the data equally well, but give different answers. Imposition of constraints on answers from core measurements viz. porosity, mineral volumes and grain density and production testing results on input / output parameters, makes the formation evaluation more realistic and reliable in a particular geological setting. This is why inversion is performed only after the availability of core measurements of porosity, mineral volumes of the rock constituents and water saturations.

In case of mixed mineral model, log response parameters for the respective rock components have to be derived from partial effects seen on the log by using linear extrapolation technique on cross plots where 100% log responses of the different constituents are defined as vertices of a multidimensional polygon demarcated by the number of available log measurements. The error associated with the mineral endpoint selection is, in most cases, much larger than that resulting from the linear approximation. Linear approximations are also adequate when uncertainties associated with invasion and hydrocarbon density etc. are considered (Yadav et al, 2003).
Study Area

The present study deals with wells which are located in the southern part of NEC block of Mahanadi-NEC basin. Sediment supplies in the North East Coast (NEC) basin area in India are probably controlled by multiple sources, viz. Ganges and Mahanadi, with some other minor stream supplies like Subarnarekha and Brahmani. Sediment influx from Ganges (post Mid-Miocene) is far greater than Mahanadi in terms of spatial distribution of sediments as delta and deep water deposits. Subsurface seismic data however exhibit little difference in the observed patterns in sediments derived from the different rivers.

In the wells of southern part of NEC block of study area, main sediments are constrained within submarine channel-levee complexes of Miocene section derived from Mahanadi river system. Towards the eastern side in the block, thick pile of Neogene sediments occur that have been fed by the Ganges - Brahmaputra river system. In between the sequence of sediments from both river systems overlay on each other.

The Ganges and Mahanadi river sediments have distinctive mineralologies which result from geologically distinct source areas. The upland tributaries of the Ganges drain Precambrian metamorphics (medium-high-grade schists, gneisses, quartzites, metamorphosed limestones), felsic intrusives, and Paleozoic–Mesozoic sandstones, shales and limestones along the southern slope of the Himalayas. The Ganges is also fed by substantial lowland tributaries draining Mesozoic and Tertiary mafic extrusives and the Precambrian–Cambrian shield. The Mahanadi on the other hand drains mostly Paleozoic granites, gneisses, granulite facies metamorphites e.g charnockites, khondalites, Precambrian volcanics and sedimentary rocks and Permo-Carboniferous Gondwana sediments.

XRD Analysis of SWC & Cuttings samples

XRD analysis is available in two separate clusters of wells in the southern part of NEC block, namely, X1-X2 and Y1. For X1-X2 wells, the XRD analysis of reservoir and non-reservoir rocks shows (Fig. 1a):

- In both the wells the main rock forming minerals are Quartz and Plagioclase
- Illite, Chlorite and Kaolinite as clay minerals along with siderite, pyrite, calcite as trace minerals.

This assemblage of minerals is taken as model 1 for inversion of open hole logs.

Figure 1a: Mineralogical assemblage in X1-X2 wells from XRD analysis
For Y1 well, the observations on XRD analysis are as follows (Fig. 1b):

- In reservoir as well as non-reservoir section quartz and plagioclase are present as common framework mineral. But the plagioclase percentage is more than that in X1-X2 wells.
- Illite, Kaolinite and mixed layered Smectite is present but chlorite is absent.
- Siderite, pyrite and calcite are also present as trace minerals.

This assemblage of minerals is taken as model 2. The two mineralogical models are used for inversion of open hole logs for the wells drilled in both the clusters. Trace minerals are not considered in the models.

**XRD Analysis of Surface Samples**

Pal et al (2008) has collected surface samples from river beds of Ganges and Mahanadi and carried out XRD analysis of the clay fraction. The XRD analysis suggests significant differences between them. For example Ganges clay contains more illite (> 40% illite + mica within the clay fraction) and slightly more Chlorite than Mahanadi which has illite + mica less than 27%. On the other hand Mahanadi has more smectite (>35% mixed layer illite/ smectite in total clay fraction) and slightly more kaolinite than the Ganges clay (Fig. 2).
Multi-mineral output of Inversion

The two mineralogical models: model 1 & model 2, as identified from XRD analysis of SWC & cuttings, have been used for inversion of open hole logs. The inversion results of X1-X2 cluster of wells and Y1 well are shown in Fig. 3:

Figure 3: Multi-mineral output of inversion of open hole logs in X1-X2 & Y1 cluster of wells
Integration for Provenance Analysis

The multi-mineral output of inversion of logs is integrated with XRD analysis of surface samples. It was found that sediments around Y1 cluster are mostly derived from Mahanadi system due to the presence of higher Kaolinite. The sediments from X1-X2 cluster are derived from feeder system from both Ganges and Mahanadi area as multi-mineral output shows bands of higher Kaolinite and Chlorite (Fig. 4). In the study it has been assumed that clay minerals derived from inversion of open hole logs are predominantly of primary origin. Significant intermixing of sediments from both the sources can also compound the analysis.

Clay typing helps to determine the reservoir quality. Kaolinite, which occurs as discrete particle clays, slightly lowers down the porosity and permeability of the reservoirs. Illite, commonly known as the pore bridging clay, decreases the porosity slightly but destroys the permeability. Smectite adsorbs water and causes expansion resulting in blockage of pore spaces. So if in a reservoir, the XRD data and open hole log inversion results show more of pore bridging clays the reservoir permeability will be drastically lower than that in case of discrete clays.
Conclusions

Understanding the source of sediments is an important criteria for reservoir quality determination. The present study in the NEC Mahanadi basin mainly deals with the integration of the inversion of the open hole logs with the XRD mineralogy. The Neogene Period of the study area is dominated by Ganges river system whereas Miocene Epoch is mainly fed by Mahanadi while there is considerable intermixing from both the rivers in many parts of the area.

Inversion of the open hole logs in the wells namely X1 & X2 when calibrated with XRD results show the presence of quartz & plagioclase as framework minerals & Illite, Chlorite and Kaolinite as clay minerals whereas the Y1 cluster shows different assemblage where there is increase in plagioclase percentage and kaolinite & Illite-Smectite being dominant clay minerals.

The results of inversion of open hole log analysis were integrated with present day surface sample analysis results where the Ganges fed sediments have higher Chlorite than Mahanadi derived sediments and Mahanadi derived sediments show higher Kaolinite than Ganges derived ones. However some amount of dilution of provenance clays are expected due to diagenesis and also the signature is expected to be complicated where significant interference/ intermixing of sediments from both the river systems is present.

The amount and clay types and their relative proportion plays an important role in reservoir deliverability. Sediments with Kaolinite as clay mineral are expected to be better reservoir than sediments with Illite. Hence proper understanding the details of reservoir mineralogy and source of sediments helps in assessing reservoir quality for exploration and development purposes.

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Resolving Flow Characterization Uncertainties in Complex Weathered Trap/Basement Sections with Barefoot and Perforated Tubular Completion with Production Logging

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Keywords
Production Logging, Reservoir characterization, barefoot completion, Perforated Tubular completion, Weathered Trap, Basement

Summary
Production logging is an important diagnostic tool for reservoir evaluation which provides vital information about well performance to take remedial actions. Through it, we can not only get the zonal contributions, but also evaluate the casing/tubing integrity and channelling behind casing. Time lapse PL measurements provides help us in monitoring the movement of fluids contacts. Multi bean Production logging provides invaluable information of reservoir parameters like Average Reservoir Pressure, Productivity Index and Skin thus helping in taking critical decisions of re-perforation and re-completion.

Extensive PL campaigns in a particular field with multiple open pays help us to assess the ascertain the contribution of individual layers within these pays which enables us to get a good idea about reservoir performance with regard to oil and gas production or water cut. The information gained from production logging can be used to help companies in defining field economics and thus to make the most appropriate decisions for field development and reservoir management.

In unconventional reservoirs, like Trap/Basement, where it is difficult to precisely locate the hydrocarbon zones through conventional standard logs, we have to increasingly rely on hydrocarbon shows during drilling through cutting data. In such reservoirs, which on production testing produce hydrocarbons Production logging can actually identify the zones contributing towards production. These flowing zones can then actually be correlated and mapped to fractures derived from Image/Acoustic logs.

The present paper presents case studies of exploratory wells in Western Offshore wherein production logging helped in identification of hydrocarbon producing zones in Trap and basement sections which are either completed barefoot or with perforated tubular.

Case Study 1: Well-A

Well-A, a recent shallow water exploratory well in Western Offshore Basin, was drilled down to X520m with an objective to upgrade the PS (probable) category reserves in Mid Miocene & Early Eocene and to explore the Paleocene section in the fault block west of ABC-3.

Object-I, consisted of Deccan Trap (X452-X520 m) along with sedimentary section of 29 m thickness (int: X423-X452m) of Paleocene age, was completed with barefoot in the interval X423 – X520 m. On testing, with DST, Object-I produced gas @1,30,000 m3/day through 1/2” choke. Three more objects, namely Objects II, III& IV, were also identified. These three objects are in 9 ⅝” casing (9 ⅝” Casing shoe is at X423m). In Object-II (Intervals: X388.0-X391.0 m & X363.0-X365.5m), which is in Nakhatrana formation, gas was collected in MDT samples against the intervals. Objects III (Int: X244.0-X247.0m) & IV (Int:
X748.0- X750.0m) are in Jakhau and Chhasra formations respectively. Hence a baseline production logging was planned in this well with barefoot completion to:

1. Identify the zones of production from barefoot section of Deccan Trap and sedimentary section of Paleocene age
2. Confirm or reject any probability of gas channeling behind the casing from above-mentioned intervals of Object-II

**Figure 1: Well A-OH motif showing the Trap Section**

**Challenges:**

Barefoot completions, due to uneven borehole conditions, pose an uphill challenge to record production logs. Suspended solid particles in the fluid flow may clog the ports of gradio-manometer and if they get entrapped inside the caliper cage may prevent in closing the cage leading to stuck up in extremely unfavorable conditions. It is also very difficult to clean the tool down-hole in gas wells. To avoid such difficulties medium size caliper arms were used in logging as a precaution to reduce the tool stuck chances in the operation.

In the current PLT which was carried out under extremely hostile conditions, several challenges during execution of the job were encountered. In the process of recording of PL (14 hours shut in and flowing passes), tool string could got held up at X460m. Thereafter, the well had to be closed for operational exigency. Afterwards, during recording of build-up data, the tool string got stuck at X351 m and could only be released by applying extra pull. On pulling out of hole, lumps of cement pieces were found entrapped inside the caliper arms.

After servicing, the tool was again lowered for repeating flowing passes but the string could not be lowered this...
and it was released by pumping sea water. The pressure too was unstable in the well and hence the spinner passes were inconsistent. In spite of extremely hostile wellbore environments, quality production log data could be successfully acquired and qualitative interpretation was carried out with the help of temperature log, fluid density and spinner flowing stations.

**Results and Conclusions**

Flowing passes acquired in the barefoot section (Fig-1), revealed considerable variations in Pressure and also spinner response is seen to be very erratic due to variations in the diameter as seen from PLT sensors. The Digital Entry Fluid Tool (DEFT) response indicated that the first hydrocarbon entry was around X454.0m. Traces of water production was also observed down hole.

On the basis of flowing spinner station data, the temperature and fluid density (Fig-2), it was concluded that the major fluid entry is from the interval X452.0 – X454.0 m and minor entry is from X438.0 – X439.5 m. Fluid density data coupled with large cooling effect on temperature sensor suggested that the produced fluid is mainly gas. Though, logs could not be recorded below 1460m, flowing spinner station data indicated that there is hardly any contribution below 1454m.

14 hours Long shut-in temperature logs recorded in the interval X305 - X460m in casing and barefoot section, ruled out the possibility of gas channeling down behind the casing. Thus, recorded production logs were instrumental in identifying the Gas producing zones from Weathered Trap barefoot section in this well which otherwise would not have been possible from conventional open hole logs.

![Figure 2](image-url)  
*Figure 2: Flowing Logs showing erratic spinner response. Fluid density and temperature response show major hydrocarbon entry at X452.0 – X454.0 m with DEFT identifying 1st Hydrocarbon entry at X454.0m*
and it was released by pumping sea water. The pressure too was unstable in the well and hence the spinner passes were inconsistent. In spite of extremely hostile wellbore environments, quality production log data could be successfully acquired and qualitative interpretation was carried out with the help of temperature log, fluid density and spinner flowing stations.

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Figure 3: Merged temperature response with spinner and caliper readings. Temperature anomaly and flowing spinner stations suggested major gas production from the top of weathered trap across the interval X452 – X454m. Minor gas production was also observed from the interval X438 – X439.5 m MD as seen on flowing spinner stations and long shut in temperature log. No gas channeling was observed behind the casing.

This is for the first time that commercial production of hydrocarbons from Weathered Trap/Trap Section has been established in this area. These results have provided a new dimension in understanding Production dynamics of the reservoir.

Case Study 2: Well-B

The well B is an exploratory deviated well (31°) in Western Offshore drilled with the objective to explore Hydrocarbon potential of Basal Clastics & Basement. The drilling was terminated at Y345m within the Basement. A total of 383m of Granitic Basement section was drilled in this well. A total of 5 objects were identified in this well for production testing with Obj-1 in the interval X967-Y345 m completed in 8 1/2" open hole with 2 7/8" perforated tubing. On activation the well flowed 50% oil and 50 % water through 1/2" choke. PLT was planned with the objective to identify flow zones contributing to production and quantification of flow rates in the tubing above packer.

Constraints of PLT in Perforated tubing:
In completions with perforated tubulars a part of the fluid will flow within the tubular and a part in the annular space between 8 1/2” section and perforated tubing . In such a case the logging sensors can see only a part of the fluid which are confined to the tubular section, due to which the PL analysis will be subjective in nature. However, the flow zones can be detected from the response of temperature log and its derivative.

The well was taken up for Production Logging and shut in passes were acquired. Only one flowing pass was acquired due to well not being completely stable . The well was given back and after further activation by CTU and stabilization the well was taken up for acquiring flowing passes after a week.

Results and Conclusions:
Major oil entry is seen in the intervals Y176-Y215m and Y259-Y273m. The interval below Y273m is only producing water. An entry is seen at Y108 m. Across all these zones contributing towards production a very high density of open fractures are seen as per Image/Acoustic logs. The total flow rates calculated above packer were oil@ 163 BOPD and water @665 BWPD.
Case Study 3: Well-C
The well C is an exploratory vertical well in Western Offshore drilled with the objective to explore Hydrocarbon potential of Panvel, Basal Clastics & Basement sections. The drilling was terminated at Y120 m within the Basement. A total of 206 m of Basement (Basaltic) section was drilled in this well. Hydrocarbon shows with pale yellow fluorescence and mild to moderate cut were reported in many intervals within the basement. A total of 4 objects were identified for production testing in this well. Object-1 within the basement was tested by DST string assembly in barefoot in the interval X914-Y120 m and on activation produced oil @ 62 BOPD and Gas @ 13433 SCMD through 3/8” choke. PLT was carried with the objective to identify flow zones contributing to production. Prior to PLT, cement evaluation was carried out in the 9 5/8” casing.

Results and Conclusions
Due to constraints of Rig height, PLT tool without flow-meter was lowered through the DST assembly. It was seen from temperature and fluid density sensors that only 13 mts of the total interval in basement was contributing towards production. Also, no flow was seen below Y000 m which was found out from the merge of temperature of both flowing and Shut in survey. Seeing the low liquid rate at surface an acid frac job was carried out in the entire basement section. Surface rates were measured and the flow rates were seen to improve significantly with oil @ 187 BOPD and gas @ 39429 SCMD with no water reported at surface. A repeat PL survey was done to see any additional flow zones after post frac, but it was seen that the producing interval remained same as in Prefac, but improvement was seen in the temperature and fluid density response which indicated lesser cooling effect and increase in the fluid density from 0.7 gm/cc to 0.8 gm/cc suggesting enhancement in oil rate. It was also seen that the THP more than doubled from 220 to 500 psi from prefac to post frac. Additionally, an increase in flowing bottom hole pressures from 649 psi in prefrac PLT to 1198 psi in post frac PLT suggests an improvement in the permeability of the contributing interval. As the cement bondage was found to be good from USIT logs the possibility of channeling from identified intervals above the casing shoe was ruled out. The flow zones were then correlated to fractures identified by Image logs. It was seen that fractures both natural and induced were present against the flowing intervals whose strike were similar in alignment and this was further validated by the direction of fast shear derived from Acoustic logs.

Figure 4: PL Logs showing temperature anomalies at intervals Y183, Y213 m and Y262 m in flowing conditions

Figure 5: Showing high fracture density against zones contributing to production in the interval Y176- Y215 m. The fractures were integrated with stoneley fracture analysis and were observed as open fractures.
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Figure 6: Showing Prefac and Post Frac PL results.
Field. More than 100 core plug samples from 8 wells have been used to measure Mercury Injection Capillary Pressure (MICP) and Air-Brine Centrifuge Capillary Pressure during SCAL analysis. Besides SCAL analysis, all 8 wells have RCA reports and a complete suite of wireline logs. Both MICP & Centrifugal data set have been used to derive saturation height functions using J function technique proposed by Leverett.

The entire calculation has been carried out in MS Excel. For validation purpose, Saturation Height Function derived water saturation has also been compared with log derived water saturation and a fair match has been observed between the two.

Data Availability
GSPC has carried out coring job in 11 wells in various depths of Lower Cretaceous section. Detailed laboratory analysis of core data has been carried out. Mercury Injection Capillary Pressure (MICP) has been carried out in 118 Core plugs of 8 wells (KG-A, KG-B, KG-C, KG-D, KG-E, KG-F, KG-G & KG-H) are used in this present study. Centrifuge Air-brine Capillary Pressure experiment data are available from 9 plug samples of KG-C.

Introduction
KG-OSN-2001/3 Block operated by GSPC is a HPHT gas block with multilayered tight Sandstone reservoirs of Lower Cretaceous age with permeability ranging from 0.01 - 1 mD, porosity ranging between 3% - 15% and gross reservoir thickness extending to 500 - 1300 m. The reservoir rocks are highly heterogeneous, dirty sand bodies deposited in a fluvial environment. Log data interpretation in some of the sections tends to overestimate the water saturation due to relatively high percentage of shale in the reservoir.

It has thus been attempted to derive a log independent saturation height function based on Capillary Pressure data obtained from core which may be used for reservoir modelling. Capillary pressure reflects the interaction of rock and fluids, and is controlled by the pore geometry, interfacial tension and wettability.

In this study, saturation height function has been derived for Lower Cretaceous section of Deen Dayal

![Figure 7: The box indicates major flowing intervals as per PL. The flow zones were mapped to the fractures (Natural & Induced) in the interval from 1975-1990 m along with Fast shear.](image)

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The authors are sincerely thankful to management of ONGC for permitting publication of the paper. The authors are also thankful to team from Western Offshore Basin, ONGC and Schlumberger, Mumbai for valuable inputs and suggestions.
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Figure 1: Map showing study area & well locations

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Figure 7:

The box indicates major flowing intervals as per PL. The flow zones were mapped to the fractures (Natural & Induced) in the interval from 1975-1990 m along with Fast shear.
Methodology

Core analysis in laboratory

Core plugs were cut from the core data systematically and cleaned. The clean samples were oven dried to constant weight at 95°C. Subsequently, following analysis were carried out on each core plugs.

Overburden Porosity Estimation

Porosity was determined in two stages. Initially each sample was placed in a sealed matrix cup. Helium held at 100 psi reference pressure was then introduced to the cup. From the resultant pressure drop, the unknown grain volume was determined from Boyle’s Law. Bulk volume was determined by Archimedes principle.

\[ \frac{P_1V_1}{P_2} = \frac{P_2V_2}{P_2} \]

\[ \Rightarrow P_1V_1 = P_2(vr + vc + vl + vg) \]

Where, \( P_1 = \) initial pressure (psig), \( V_r = \) reference cell volume (cm3), \( V_c = \) matrix cup volume (cm3), \( V_l = \) line volume (cm3), \( V_g = \) grain volume (cm3) & \( P_2 = \) final pressure (psig)

and

\[ \rho = \frac{V_g}{W_t} \]

where \( \rho = \) grain density (g/cm3), \( W_t = \) weight of sample (g) & \( V_g = \) grain volume (cm3)

The samples were then placed into individual thick walled rubber sleeves and the assembly loaded into a hydrostatic cell. With an ambient pressure (400 psi) applied to the sample, helium held at 100 psi reference pressure was released into the samples pore volume. The confining pressure was then increased to the selected overburden pressures of 4000 psi and the resultant change in internal pore pressure was monitored and used to determine pore volume at overburden conditions.

\[ V_p = vb = V_g \]

\[ \text{Ambient Porosity}\% = \frac{V_p}{V_b} \times 100 \]

\[ \text{Overburden Porosity}\% = \frac{V_p - \Delta V_p}{V_b - \Delta V_p} \times 100 \]

where \( V_p = \) ambient pore volume (cm3), \( V_b = \) ambient bulk volume (cm3), \( V_g = \) grain volume (cm3) & \( \Delta V_p = \) change in pore volume (cm3)

Overburden Permeability Estimation

The samples were then placed into a hydrostatic cell with a simulated overburden confining pressure applied. In order to determine permeability a known air pressure was applied to the upstream face of each sample, creating a flow of air through the core plug. Air permeability for each core sample was calculated using Darcy’s Law through knowledge of the upstream pressure, flow rate, viscosity of air and sample dimensions.

\[ k_a = \frac{2000.BP.\mu.q.L}{(P_1^2 - P_2^2).A} \]

where \( k_a = \) air permeability (milliDarcy’s), \( B = \) barometric pressure (atmospheres), \( \mu = \) gas viscosity (cP), \( q = \) flow rate (cm3/s), \( L = \) sample length (cm), \( P_1 = \) upstream pressure (atmospheres), \( P_2 = \) downstream pressure (atmospheres) & \( A = \) sample cross sectional area (cm2)
Measuring mercury injection capillary pressure

Sample off-cuts of sufficient volume to fill the sample chamber were utilised for capillary pressure determinations by the mercury injection technique. Micromeritics Autopore apparatus was used for this experiment. This apparatus can operate up to a pressure of 60,000 psia, and can measure intrusions as small as 0.0001 cm³.

The Micromeritics Autopore records mercury intrusion by measuring the capacitance change between the capillary of mercury contained in the penetrometer and an outer metal sheath as mercury invades the samples. For pressures up to 24 psia, air pressure was used. Hydraulic oil was used to achieve the higher pressures. All samples were dried in a humidity oven and placed into calibrated glass penetrometers. These consist of a sample chamber and attached precision bore capillary. Once the samples were placed into the penetrometer a vacuum was applied until less than 50 micrometres of mercury had been achieved. Mercury was then introduced into the penetrometer and the run commenced along pre-defined pressure points on a logarithmic scale. After equilibration at each pressure point, a capacitance reading was taken which was then converted into an equivalent intrusion volume. Pore throat diameter for intrusion pressure can be calculated as such:

\[ D = \frac{4T \cos \theta C}{\rho} \]

Where, \( D \) = pore throat diameter (microns), \( T \) = interfacial tension (dynes/cm), \( \theta \) = contact angle (degrees), \( P_c \) = capillary pressure (psi) & \( C \) = conversion constant = 145 x 10⁻³

Measuring air-brine capillary pressure

The fully saturated sample was placed in an individual drainage cup under air. The cup was loaded into the centrifuge and the brine displaced by centrifugal forces was monitored as a function of time. As standard practices require, samples were left at each required rotational speed for a minimum of 24 hours. The induced capillary pressures were then calculated from the following equation 2:

\[ P_c = \frac{1}{2} \Delta \rho \omega^2 (r_2^2 - r_1^2) x (1.013 \times 14.696 \times 10^{-6}) \]

Where, \( P_c \) = capillary pressure at the inlet face of the core (psi), \( \Delta \rho \) = density difference of the two fluids, i.e. air and water (g/cm³), \( \omega \) = angular velocity (rad/s) = 2π (RPM)/60, \( r_2 \) = radius from the centre of the centrifuge to the bottom of the core plug (cm) & \( r_1 \) = radius from the centre of the centrifuge to the top of the core plug (cm)

The centrifuge method of determining the relation between saturation and capillary pressure provides values of average saturation. These average saturation values were then converted to obtain the endface saturation which is equivalent to the induced capillary pressure, thereby obtaining the true profile of capillary pressure versus saturation. The true endface saturation has been calculated by applying a series of data regressions to the average saturation values and is the value to be used in reservoir modelling.

Methodology of deriving J function in spreadsheet

An attempt is made to establish Leverett J-Function for the Lower Cretaceous section and to arrive at an initial water saturation distribution for Upper Cretaceous reservoir section using Microsoft Excel. Leverett J-function is a dimensionless function of water saturation describing the capillary pressure. The equation is:

\[ s_w = s_{wb} + a * J^{-\lambda} \ldots Eqn \]
Where, \( Sw \) = Water Saturation in fraction of pore volume, \( Swb \) = Irreducible water saturation in fraction at the end point & \( a, \lambda \) = fitting parameters.

Since, only linear regression is available in Excel, J function has been made linear taking logarithm of the above mentioned function.

\[
\log(sw - swb) = \log(a)\lambda .\log(I) ... \text{Eqn}
\]

This equation linearly relates to with. In this linear form, appropriate terms can be calculated in spreadsheet. To calculate the log (Sw - Swb), 'Swb' value must be estimated. At the initial stage of calculation, a value for 'Swb' was estimated. Precise value of 'Swb' was optimised later.

'LINEST' function is used to define two fitting parameters' & 'a' using data column and Log (J). In MS Excel, LINEST Function uses the least squares method to calculate the line of best fit for a supplied set of y- and x-values. In this case column is defined as x- values and Log (J) is defined as y-values. Since two fitting parameters are estimated, two columns are defined for the regression array. Additional statistics are produced totalling 5 rows in each column (Figure 2).

Irreducible water saturation (Swb) is later fine tuned to optimise correlation coefficient using 'GOAL-SEEK' function. In computing, goal-seeking is the ability to calculate backward to obtain an input that would result in a given output.

Separate attempts have been made to derive the J-function using MICP data as well as Centrifuge Air-Brine Capillary Pressure data. First, capillary pressure (Pc) Laboratory data were plotted against the saturation to check the data quality. Then, filtered Pc data were converted to reservoir condition using following equation.

\[
P_{c_res} = \frac{\sigma (\sigma \cos \theta)_{res}}{\sigma (\sigma \cos \theta)_{lab}} \times P_{c_{lab}}
\]
where, 
\[ \theta = \text{Contact angle between the two fluids, } \sigma = \text{Interfacial tension in } \text{Mn/m}, \]
Laboratory provided ambient porosity (\( \rho \)) & permeability (\( k \)) data have been converted to overburden condition using the equation derived from RCA porosity & permeability data. Using the following equation with proper unit conversation constant, values of J function is calculated.

\[
J = \frac{Pc_{res}}{\sigma (\sigma \cos \theta)_{res}} \left( \frac{k}{\phi} \right)^{0.5} \quad \text{Eqn 4}
\]

where, \( J = \text{dimensionless function, } \rho = \text{overburden porosity in volume fraction, } k = \text{overburden permeability in mD} \)

Calculation of J Function vs. \( Sw \) is plotted for all the samples of Centrifuge Air-Brine Capillary Pressure data and a curve is fitted in the plot (Figure 3). MICP derived J-Function has been found to be inconsistent as the derived J function does not follow the trend of the core plug derived capillary pressure curves. However, Centrifuge Air-brine Capillary Pressure data gave a consistent J-Function which was used for further studies (Figure 4).

Parameters derived from the fitting curve of Air-brine \( Pc \) data are i) Irreducible water saturation (\( Swb \)) = 10\%, ii) Curve fitting constant \( a = 0.787251 \) & iii) \( \lambda = 0.157626 \). Therefore, the derived J function is as below

\[
Sw = 0.1 + .787251 * J^{-(0.157626)} \quad \text{Eqn 5}
\]

After deriving the Leverett J-function, the same has been used to calculate water saturation for various wells. Reservoir height (\( H \)) calculated assuming a Free Water Level. Following equations were used to calculated water saturation using J-function.

\[
Pc = \Delta \rho * g * H
\]

\[
Sw = b + a * Pc(K / ?)^{0.5(-3)}
\]

where, \( Pc = \text{Capillary pressure calculated for the well, } \rho = \text{Density difference of gas & water in } \text{g/cc, } H = \text{Height above free water level, } G = 9.81 \text{ N/kg, } \text{b= Irreducible water saturation from J-function, } a & \lambda = \text{Curve fitting constant obtained from J-Function, } \rho^*G = 0.1346. \)
Conclusion

Leverett J-function derived water saturation has been compared with the water saturation derived from the logs. A fair match has been observed between the two curves at clean reservoir section (Figure 5). Significant mismatch has been observed at shaly-sand section due to pessimistic estimation of Sw from log data (Figure 6). In well KG-H, interval between 4692 to 4752m produced more than 5 mmscf of dry gas. For the same shaly-sand interval, computed average Sw is 77% whereas Sw computed using Saturation height function is less than 49%.

MICP data, though available extensively, did not give convincing match probably due to the data quality. Thus, it was not possible to derive a J-Function using the MICP data.

Air-brine Capillary Pressure data derived J Function have been used to calculate initial water saturation which has given satisfactory results. This function has also been used to derive water saturation in different wells across the field.

![Figure 5: KG-C well showing match between function derived Sw (black curve in Track-7) & log derived Sw (shaded curve in Track-7) in Good Reservoir](image)

![Figure 6: KG-H: DST-2 Interval 4692-4752m showing mismatch between function derived Sw and log derived Sw in shalier sections](image)

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Challenges in Formation Evaluation of A Tight Oil Reservoir: A Case Study of A Porcellanite Field in the Barmer Basin, India

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Abstract

Characterization of transition zones in tight oil-bearing reservoirs and the vertical distribution of water saturation are critical in estimating the original oil in place (OOIP), placing perforations and hydro-frac intervals for production, predicting water breakthrough and reservoir modeling for dynamic simulation. This paper presents a case study of a tight porcellanite reservoir from the Barmer Basin, India. Identification of the oil-water contact (OWC) based on log analysis can be ambiguous due to longer transition zones in NL-BH low-permeability reservoirs, especially due to the limited number of well penetrations. The lack of good quality formation pressure data is an additional challenge, because in tight reservoirs, formation pressure tests are often affected by supercharging or fail to achieve a stable pressure due to the very limited drawdown mobility. This study deals with a technique to determine the OWC and free water level (FWL) for a tight reservoir by integrating geological and engineering data such as well logs, routine and special core analysis, fluid samples and flow test data. Resistivity-based Sw estimates, constrained by core measurements, along with a mercury injection capillary pressure (MICP) based saturation height function, were used to derive the FWL and possible range of OWCS to define the field limit in NL-BH. Additionally, NMR logs have been used effectively in identifying zones in a transition state with movable water. A theoretically sound solution has been proposed based on capillary pressure concepts that can address the common problem of estimating fluid contact and water saturation distribution in tight reservoirs.

Introduction

The N-L Barmer Hill Field (NL-BH), located in the northern Barmer Basin, northwest India, is an oil discovery made by Cairn India Limited in 2014. The primary Barmer Hill Formation reservoir facies is biogenic microcrystalline quartz, commonly referred to as quartz-phase porcellanite due to its porcelain-like texture. Porcellanite is diagenetically altered siliceous diatomite characterized by good porosity (~10-25%) but low matrix permeability (~0.01-2mD) in NL-BH Field. The reservoirs are highly laminated, with millimeter to centimeter scale laminations of porcellanite, claystone and organic material, and as such they are difficult to distinguish in well cuttings and are typically described as argillaceous siltstone. They are dominated by micro porosity with pore sizes ranging between 0.01-1 microns (Figure-1). Generally, an increase in formation gas is observed during drilling and cuttings show oil staining when hydrocarbons are present. Conventional testing with only perforations results in either no flow or production at sub-commercial rates from these reservoirs. However, application of hydraulic fracturing typically results in a multi-fold increase in production rates. Commercial development of analogous low permeability reservoirs in other fields within the Barmer Basin is currently underway using multi-stage hydraulic fracturing.
Figure 1: The NL-BH Field porcellanite reservoirs in log, core and thin-section. The porcellanite are tight, highly laminated, micro porosity dominated rocks with pore sizes <1 micron.

Tight reservoirs have longer transition zones than multi-darcy reservoirs, and these tight-rock transition zones can produce both oil and gas. The transition zone is defined as the interval between the oil-water contact (OWC) and an upper boundary, above which formation water is immobile. A considerable thickness of the low permeability reservoir rock within the transition zone can have mobile oil, although the lower portion of the transition zone may have oil saturations ranging from infinitely small to the residual oil saturation. The lowest horizontal boundary in a reservoir, at which the capillary pressure (Pc) becomes zero, is the free water level (FWL).

When the OWC and FWL of an oil reservoir are conclusively identified, Sw distribution can be predicted with the help of Pc data measured from conventional cores. The saturation-height function can be devised after performing needful corrections to the Pc data and converting them to reservoir conditions. The height, h, is equal to zero at the FWL, where Sw=100%. Above FWL, Sw remains 100% till the point where buoyancy pressure becomes equal to capillary pressure. Pressure at this point is also termed as capillary-entry pressure (Pce), above this pressure oil starts entering the pore system. The OWC is located at a distance above the FWL equal to the capillary-entry height (Hce), where the Sw starts decreasing from the value of 100% (Figure-2A).

Figure 2(A): Schematic of conventional capillary pressure curve; (B) Schematic showing effect of matrix permeability on capillary pressure vs. water saturation.
Pc is directly proportional to the height above FWL and also affected by permeability of the rocks. In porcellanite reservoirs, the matrix permeability controls the shape and magnitude of the capillary pressure curves as seen in the MICP data. Important parameters in defining these curves such as entry pressure, irreducible water saturation and slope of transition zone curve are found to have strong correlation with the matrix permeability of the rocks (Figure-2B).

Oil saturation within porcellanite reservoirs in the NL-BH Field is found to be largely controlled by height above the free water level and the matrix permeability. The core data shows that capillary entry pressure (Pce) in these rocks usually correlates well with the permeability (Figure-3C). Low permeability equates to a higher entry pressure in porcellanites; hence there is a significant thickness of reservoir rock above free water level with no hydrocarbon saturation in the NL-BH Field (Figure-3A & B).

Figure 3(A): MICP data from the NL-BH Field clearly shows variation in entry heights with varying permeability within the porcellanite reservoirs; (B) A schematic showing the impact of permeability on the free water level and oil water contact; (C) Relationship of the entry pressure with permeability in NL-BH Field; (D) Relationship of the entry height with permeability in NL-BH Field.

A robust permeability model is critical in deriving a mathematical function to predict entry heights and Sw accurately. Determination of the height of the OWC above free water level is important in defining the field limit. However, in the NL-BH Field, because the limited well data do not directly define the FWL, the application of saturation height function in conventional way is challenging. The majority of the attempted formation pressure measurements with wire line tester in the NL-BH Field reservoirs were found to be supercharged, making them unsuitable for any gradient analysis to determine the free water level.
This paper outlines a technique to estimate the OWC in a tight reservoir using capillary pressure data, leading to an improved estimation of field limits and in-place hydrocarbon volumes. The workflow integrates resistivity based Sw estimates along with a mercury injection capillary pressure (MICP) based saturation height function to derive the free water level and possible range of OWCs to define the field limit. Additionally, NMR logs have been used in characterizing transition zone saturations and identifying zones with moveable water. Core calibrated irreducible water saturation (Swirr) estimated using NMR logs can be used to identify zones with abundance of movable water. This allows for better placement of production intervals to avoid zones of high mobile water.

**Data used**

Wire line logging, conventional core analysis and the fluid sampling plan in the NL-BH Field were designed so that every piece of data could be efficiently integrated to characterize the reservoir properties and fluid distribution. The field was penetrated by 6 wells, with one appraisal well drilled in the water leg. None of the wells have intersected the OWC. All wells have triple combo logs (Resistivity, Neutron, and Density) recorded either in LWD or with wire-line. Additionally, NMR logs are available in two of the wells and have been used extensively in the petrophysical characterization. Formation pressure measurements attempted in two of the wells yielded only supercharged pressure points due to tightness of the formation.

Thirty-two meters (32m) of conventional core were acquired from the NL-BH field and were used for a variety of analyses, with plugs taken from the slabbed core. Both vertical and horizontal plugs were taken, and with the cored intervals having low bedding dip (less than 15° with respect to core barrel), and it was ensured that the horizontal plugs are bedding/lamination parallel. Routine core analysis (RCA) testing for porosity, permeability and grain density were done for 42 plugs. The porosity-permeability measurements have been performed both at ambient and net overburden (NOB) conditions and have gone through a rigorous quality check. A total of 50 plugs were shortlisted for various special core analysis (SCAL) studies in NL-BH cores. Plug selection for SCAL studies were made to ensure data collection from the full range of porcellanite reservoir properties. All plugs initially deemed suitable for SCAL have undergone CT scanning to omit the fractured plugs (as parting along laminations is common in porcellanite). Different SCAL studies performed include formation resistivity factor (FRF), formation resistivity index (FRI), core NMR at elevated temperature, mercury injection and centrifuge capillary pressure and unsteady state relative permeability experiments.

Formation fluid samples collected through dual packer wire-line tester tool and from NL-BH production formed an important basis of validating the results obtained from the present study. Laboratory PVT analysis of bottom-hole water and oil samples were also available in the NL-BH Field and integrated into this study. The salinity of the formation water is approximately 16,500 ppm (NaCl equivalent) and the reservoir temperature is 65-70°C. The PVT data at reservoir conditions is provided in Table-1.

<table>
<thead>
<tr>
<th>Oil density (g/cc)</th>
<th>Water density (g/cc)</th>
<th>Oil viscosity (cp)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.86</td>
<td>1.01</td>
<td>10-12</td>
</tr>
</tbody>
</table>

**Table 1:** Fluid properties in NL-BH field

Wettability, oil-water interfacial tension (IFT) $\sigma$ and contact angle $\theta$ were not measured in the NL-BH core. However, available USBM wettability measurements in nearby porcellanite analogue fields are predominantly neutral wet. Hence, the typical values at these reservoir conditions, IFT=30 dyne/cm and $\theta$=30 degree respectively, are used in converting the capillary pressures to reservoir conditions.
Methodology

The core-measured porosity to permeability relationship established in NL-BH has been integrated with the NMR log to validate log porosity and to generate a calibrated continuous curve of matrix permeability. This was, in turn, also used to optimize the selection of SCAL plugs. A well constrained estimation of resistivity based Sw was achieved through electrical properties measured on cores and laboratory water sample analysis. High pressure mercury injection capillary pressure (MICP) tests were conducted on 30 core plug samples in NL-BH Field. The following workflow is adopted to build a saturation height function based on a modified Skelt-Harrison technique:

1. Obtain Pc (lab) vs. Sw from the capillary pressure lab test
2. Convert Pc (lab) to Pc (res) using equation below:

\[ \sigma z \approx \int \rho(z) \cdot g \cdot dz \]  \hspace{1cm} (1)

3. Apply appropriate closure correction to required plugs
4. Convert Pc (res) to height using density differences of formation oil and water:

\[ h = \frac{Pc}{(p_w - p_a)g} \]  \hspace{1cm} (2)

5. Fit the following equation on all good plugs to compute values of A, B, C & D through regression

\[ Sw = 1 - a \cdot \exp\left(\frac{B}{(h + D)g}\right) \]  \hspace{1cm} (3)

6. Cross-plot Coefficients A, B, C and D with permeability (K) (Figure-4). Below are the relationships established for NL-BH reservoir:

\[ A = 0.75 \cdot K^{-0.047} \]  \hspace{1cm} (4.1)
\[ B = 150 \cdot K^{(-0.374)} \]  \hspace{1cm} (4.2)
\[ C = 2.3 \cdot K^{0.066} \]  \hspace{1cm} (4.3)
\[ D = 0 \]  \hspace{1cm} (4.4)

![Figure 4: Correlation of permeability with co-efficients A, B and C used in modified Skelt-Harrison technique to predict Sw.](image)

7. Predict Sw for a given perm.
Additionally, care has been taken so that measured entry pressures are in agreement with modeled entry pressures at given permeability while preparing the Sw-height function (Figure-5C). The saturation height function for NL-BH Field is presented in Figure-5A. Relationship used to predict permeability using porosity is presented in Figure-5B

Re-arranging the equation (3), we can solve for h provided Sw and K is known.
Example: If a pay zone lies at a depth of -800m TVDSS with permeability= 1mD, and resistivity based Sw=0.50 then, using equation 5, the height above FWL can be calculated as 222m. Alternately this can also be graphically computed using Figure 5A. Hence the FWL depth for the given reservoir would be (-800-222) = -1022m TVDSS. Then using the relationship shown in Figure 2D, the depth of OWC is calculated, which suggests that for a 1mD rock, the height of the OWC will be ~75m above FWL. Therefore the OWC depth would be (-1022+75) = -947m TVDSS.

The Sw trend observed from resistivity based estimates against different permeability rocks has been used as reference to estimate free water level using this height function. Multiple iterations for free water level were made until the height function derived Sw estimates matched the resistivity based Sw estimates for the 5 wells in the field. Figure-6 shows the match in two of the NL-BH wells.

Figure 5: (A) Saturation-height function created for NL-BH field. Modeled curves show good agreement with the core measured MICP data. (B) Porosity-permeability relationship derived from core and NMR data in NL-BH. (C) Modeled entry pressures are in agreement with measured data across the entire permeability range.

Figure 6: Well logs illustrating the match between the resistivity based Sw and height function derived Sw in two of the NL-BH wells.
To identify the presence of movable water within a reservoir interval, a realistic estimation of Swirr (irreducible water saturation) from NMR log was achieved through NMR experiments in core plugs by ascertaining the free fluid cut-offs. The NMR experiments were performed on restored state plugs at elevated (reservoir representative) temperatures to establish the free fluid T2 cut-off for porcellanite (Figure-7A). A core calibrated T2 cut-off of 30ms has been applied to estimate free fluid fraction, which in turn was used as input for estimating Swirr using equation below:

\[
Swirr = \frac{nmrBFT}{nmrPhiT} = 1 - \frac{nmrFF}{nmrPhiT}
\]  

Where,

- Swirr = Total irreducible water saturation
- nmrPhiT = Total porosity from NMR
- nmrBFT = Total Bound fluid from NMR
- nmrFF = Free Fluid from NMR

These estimations have further been validated with immobile water saturation (Swi) observed in core plugs through centrifuge experiments (Figure-7B). Comparison of Swi from NMR and resistivity based Sw identifies the oil zones at irreducible water saturation and also oil bearing zones with movable water (Figure-7C and D). The observations were in agreement with the formation fluid samples collected with dual packer formation tester tool and results of the extended well production tests.

Figure 7: (A) NMR experiments carried out in porcellanite core at reservoir conditions suggested a T2 cut-off of ~30ms as reasonable for estimating free fluid fraction; (B) The Swirr estimated using the NMR log shows good agreement with Swi from centrifuge in core plugs; (C) Log motif of a crestal well in NL-BH Field showing Sw estimates that match well with Swirr estimates, suggesting the pay zone to have negligible mobile water with a good potential for producing clean oil; (D) Log motif of a flank well in the transition state. Difference of Sw and Swirr identifies pay zones with abundant mobile water.
Results and Discussion

Prior to this study, the oil down to (ODT) observed in the well logs was used for the volumetric estimations in NL-BH Field. The OWC and FWL depths could not be estimated with the conventional dataset that is typically utilized in high permeability reservoirs. The technique discussed in this paper allows for a robust modeling of the OWC in the static model as a function of permeability by implementing the concept of capillary pressure and saturation height function. Additionally, this led to the identification of two separate pools in the NL-BH Field, each with a different free water level. The relationship established between permeability and entry pressures (and entry height) from MICP data suggest a variation of entry height ~60-300m for a given permeability range of ~0.1-1.0 mD. Swirr estimates, along with height function, provided the basis for distributing the saturation in the geocellular model as well as characterizing the longer transition zone of this tight reservoir. The results have been extremely helpful in formulating the perforation and hydraulic fracture stimulation strategy for targeting pay zones with lower amounts of mobile water.

It is important, however, that the assumptions used in this methodology are well understood. The capillary pressure curve is a function of pore radius and hence, rock type. Subsequently, the saturation-height function is dependent on the permeability of the reservoir rock. A good agreement of saturations between capillary pressure derived from a core sample and log-derived water saturation is always desired in case of reservoirs with an intact seal and with only primary migration. Either one can be used to calibrate the other; however, difference in “scale” may impact the degree of agreement between the two. The present technique should provide a realistic estimation of the fluid contact for any reservoir unless these assumptions appear to be invalid. Additionally, unavailability of adequate core measurements may lead to inappropriate assumptions while the lack of valid m and n parameters can cause errors in log calculations. This error can contribute to significant uncertainty in the FWL estimation using the Pc curves. A thorough quality control is required to reduce the errors in the capillary pressure curves due to such factors as alteration of wettability by invasion of drilling mud filtrate, biased sampling, issues in sample integrity, effect of core cleaning on wettability, errors in laboratory measurement and inappropriate corrections on the Pc curves. Wettability and fluid density variations in reservoir can have large impact on FWL estimates made using saturation-height function. Uncertainty in these estimates should be accounted, if required, based on the availability and quality of the dataset used.

Conclusion

In tight reservoirs with limited well and production test data, an integrated formation evaluation plays a key role in effective reservoir characterization and defining and executing an optimum appraisal program. In the case of the N-L Barmer Hill Field, learning from the nearby analogous porcellanite fields and a well-defined workflow helped in understanding the critical data needed, which led to a better estimate of the oil-water contact and identification of the pay zones with less mobile water. This resulted in a better-constrained geocellular static model which was used for an improved hydrocarbon in place volume estimation. The results of the petrophysical evaluation were instrumental in delineating the high productivity priority zones through dynamic simulation and identifying area of lowest development risk resulting a more effective well planning.

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Simulation and Identification

Effective reservoir characterization and defining an optimum appraisal program is critical in tight reservoirs with limited well and production test data. An integrated formation evaluation plays a key role in petrophysical evaluation, identifying area of lowest development risk, enabling a more effective well planning. The geocellular model as well as characterizing the longer transition zone of this tight reservoir led to the identification of two separate pools in the NL-BH Field. The OWC and FWL depths could not be estimated with the conventional dataset that is typically utilized in high permeability reservoirs. The technique discussed in this paper allows for a robust modeling of the petrophysical evaluation, which was instrumental in delineating the high productivity priority zones through dynamic simulation and identifying area of lowest development risk resulting a more effective well planning.

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These estimates should be accounted, if required, based on the availability and quality of the dataset used. The capillary pressure derived from a core sample and log-derived water saturation is always desired in case of reservoirs dependent on the permeability of the reservoir rock. A good agreement of saturations between capillary pressure curve is a function of pore radius and hence, rock type. Subsequently, the saturation-height function is significant uncertainty in the FWL estimation using the Pc curves. A thorough quality control is required to reduce the errors in the capillary pressure curves due to such factors as alteration of wettability by invasion of drilling mud filtrate, biased sampling, issues in sample integrity, effect of core cleaning on wettability, errors in laboratory measurement and inappropriate corrections on the Pc curves. Wettability and fluid density variations are accounting factors that contribute to the reduction in accuracy of saturation-height function. Additionally, unavailability of adequate core measurements may lead to inappropriate assumptions in reservoir can have large impact on FWL estimates made using saturation-height function. Uncertainty in pressure derived from a core sample and log-derived water saturation is always desired in case of reservoirs dependent on the permeability of the reservoir rock. A good agreement of saturations between capillary pressure curve is a function of pore radius and hence, rock type. Subsequently, the saturation-height function is significant uncertainty in the FWL estimation using the Pc curves. A thorough quality control is required to reduce the errors in the capillary pressure curves due to such factors as alteration of wettability by invasion of drilling mud filtrate, biased sampling, issues in sample integrity, effect of core cleaning on wettability, errors in laboratory measurement and inappropriate corrections on the Pc curves. Wettability and fluid density variations are accounting factors that contribute to the reduction in accuracy of saturation-height function. Additionally, unavailability of adequate core measurements may lead to inappropriate assumptions

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Effective reservoir characterization and defining an optimum appraisal program is critical in tight reservoirs with limited well and production test data. An integrated formation evaluation plays a key role in petrophysical evaluation, identifying area of lowest development risk, enabling a more effective well planning. The geocellular model as well as characterizing the longer transition zone of this tight reservoir led to the identification of two separate pools in the NL-BH Field. The OWC and FWL depths could not be estimated with the conventional dataset that is typically utilized in high permeability reservoirs. The technique discussed in this paper allows for a robust modeling of the petrophysical evaluation, which was instrumental in delineating the high productivity priority zones through dynamic simulation and identifying area of lowest development risk resulting a more effective well planning.

Results and Discussion

These estimates should be accounted, if required, based on the availability and quality of the dataset used. The capillary pressure derived from a core sample and log-derived water saturation is always desired in case of reservoirs dependent on the permeability of the reservoir rock. A good agreement of saturations between capillary pressure curve is a function of pore radius and hence, rock type. Subsequently, the saturation-height function is significant uncertainty in the FWL estimation using the Pc curves. A thorough quality control is required to reduce the errors in the capillary pressure curves due to such factors as alteration of wettability by invasion of drilling mud filtrate, biased sampling, issues in sample integrity, effect of core cleaning on wettability, errors in laboratory measurement and inappropriate corrections on the Pc curves. Wettability and fluid density variations are accounting factors that contribute to the reduction in accuracy of saturation-height function. Additionally, unavailability of adequate core measurements may lead to inappropriate assumptions in reservoir can have large impact on FWL estimates made using saturation-height function. Uncertainty in pressure derived from a core sample and log-derived water saturation is always desired in case of reservoirs dependent on the permeability of the reservoir rock. A good agreement of saturations between capillary pressure curve is a function of pore radius and hence, rock type. Subsequently, the saturation-height function is significant uncertainty in the FWL estimation using the Pc curves. A thorough quality control is required to reduce the errors in the capillary pressure curves due to such factors as alteration of wettability by invasion of drilling mud filtrate, biased sampling, issues in sample integrity, effect of core cleaning on wettability, errors in laboratory measurement and inappropriate corrections on the Pc curves. Wettability and fluid density variations are accounting factors that contribute to the reduction in accuracy of saturation-height function. Additionally, unavailability of adequate core measurements may lead to inappropriate assumptions

References

Geomechanical Solutions Incorporating Advanced Acoustic Measurements for Achieving & Improving Wellbore Stability in Structurally Complex and Tectonically Active Geleki Field

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Introduction

Assam shelf represents a classical asymmetrical/ foreland basin flanked by NE- SW trending mobile Naga Schuppen belt on the East and South-East and Arunachal Himalaya to the North and North-East. Being bounded by eastern Himalayan fold belts on the north and Naga-Patkai fold belts on the East-South-East, it constitutes a vast intermountain basin. Most of its geological features are concealed by the recent alluvial cover. The Assam Arakan fold belt has undergone severe folding, faulting and thrusting during the different phases of post collision events leading to further regional complexity in litho-facies. In the process however, the tectonic activity has created favorable traps for hydrocarbon accumulation albeit with major drilling risks. Exploration in this region has been very challenging due to complexity of structures, lithology and built-up of stresses. This led to various drilling related issues like stuck pipe, lost in hole, drill breaks, kicks etc., thus increasing NPT and cost. This resulted in bad hole condition, poor quality and incomplete log acquisition, short TD and side-tracking of those wells. Main challenges faced while drilling are stuck pipe, losses, tight pulls. This leads to severe wellbore failure, short TD, sidetracking of the hole, pre-mature cancellation of the drilling program. In addition, severe hole enlargement and rugosity through the eventual reservoir sections resulted in poor logging conditions and uncertain reservoir evaluation. Oil companies like ONGC are encountering these problems every time while drilling in this tectonically active and differentially depleted region.

Approach

This approach is based on an iterative geomechanical analysis and wellbore stability analysis integrating products from advanced sonic tool. The tool has been designed using the latest acoustic technology for advanced acoustic acquisition, including cross-dipole and multi-spaced-monopole measurements. In addition to axial and azimuthal measurements, the tool makes a radial measurement to probe the formation for near-wellbore slowness and far-field slowness. Typical depths of investigation equal two to three times the borehole diameter. To enable a deeper understanding of acoustic behavior in and around the borehole, this tool allows accurate radial and axial measurements of the stress-dependent properties of rocks near the wellbore enabling characterizing the near and far field stress regimes. These advanced sonic interpretations provide novel applications across multiple geoscience disciplines. In particular, advanced sonic products are integrated with geomechanical analysis to help in a more comprehensive understanding of the reservoir rock failure modes and to improve the understanding of the reservoir structure, improve drilling parameters and perforating design.

In this paper, a case study from the Geleki field is presented to show how an iterative geomechanics based approach integrating products from advanced sonic tool has significantly improved drilling rates by reducing the drilling-related problems and has also led to more accurate reservoir evaluation in Nazira. Well A is an S-shaped well located in Geleki field. Severe wellbore instability issues in TS 3 and LCM zones like stuck pipe, held ups, wellbore exposure for longer duration due to frequent equipment failures, mud cut and drill string failure led to sidetracking the Well A three times in 12.25” section (Fig. 1).

To prevent further wellbore instability issues in sections below and find the reason for the various drilling events, a geomechanics study was carried out in this well. Post-drill 1D Mechanical Earth Model (MEM) was constructed for 12.25” section (Fig. 2) using sonic and other open-hole logs. Pre-drill 1D MEM was...
constructed for 8.5" and 6" sections (Fig. 3) based on data from offset well B (located in same area) and using correlations from 12.25" section above. Stable mud weight window was calculated for 8.5" and 6" sections and drill mud weights were recommended and followed for these sections of the wellbore.

Since the area is highly faulted, it was recommended to fully utilize the wireline sonic measurements, after drilling and logging the 8.5" section to generate an improved model for the final 6" section in an iterative manner. Rock mechanical properties and stress models, controlling wellbore stability, were updated post logging the different drilled sections to improve the mud weight windows for the section below the latest drill bit depth.

![Figure 1: Well progress plot shows huge wellbore instability problems in LCM and TS-5A &5B formations in 12.25" section.](image1)

![Figure 2: Well-A Post-drill wellbore stability analysis for 12.25" section](image2)
Results

In 8.5" Section
By following the recommended mud weight in 8.5" section ONGC Nazira was able to drill 803m section in 16 days approximately. Reduction in wellbore instability issues has led to considerable reduction in time spent in reaming, mud circulation, cleaning tight spots etc. The wellbore is in a much better shape as can be seen from the caliper data in the 8.5" section (Fig. 4) across the BCS & BMS formations from various offset wells. Most of the wellbore enlargement as measured by 4-arm powered calipers, is observed over coal sections in BCS formation. Hole is relatively in-gauge over sand and shale sections. The shale sections where drilling was stalled due to surface equipment failure show some breakouts due to longer borehole exposure time in static condition.

Figure 3: Well-A Pre-drill wellbore stability analysis for 8.5" &6" section

Figure 4: Well-A Post-drill wellbore stability analysis for 8.5" section
Drilling time breakdown of the 8.5" section of well A is compared with offset well B. These wells are in different blocks but are used for comparison due to similarity in their casing plan and formations encountered. The two wells were spud within one month of each other. Details of the drilling time breakdown are given in the table below:

<table>
<thead>
<tr>
<th>Well Spud Date</th>
<th>A</th>
<th>B</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.5&quot; Drilling Start</td>
<td>28-Feb-15</td>
<td>10-Jan-15</td>
</tr>
<tr>
<td>8.5&quot; Logging End</td>
<td>04-Dec-15</td>
<td>08-Jul-15</td>
</tr>
<tr>
<td>8.5&quot; Drilled Section Length (m)</td>
<td>13-Jan-16</td>
<td>12-Aug-15</td>
</tr>
<tr>
<td>8.5&quot; Drilled Section Length (m)</td>
<td>803</td>
<td>730</td>
</tr>
<tr>
<td>8.5&quot; Drilling Activity (days)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Drilling (Bit on Bottom)</td>
<td>15.9</td>
<td>12.9</td>
</tr>
<tr>
<td>Tripping for Bit / BHA Change</td>
<td>8.2</td>
<td>7.2</td>
</tr>
<tr>
<td>Held Up / Reaming / Hole Cleaning</td>
<td>1.9</td>
<td>8.7</td>
</tr>
<tr>
<td>Stuck Pipe / Tool - Fishing</td>
<td>0.1</td>
<td>0</td>
</tr>
<tr>
<td>Logging</td>
<td>4.5</td>
<td>5</td>
</tr>
<tr>
<td>Equipment Failure</td>
<td>10.4</td>
<td>2.2</td>
</tr>
<tr>
<td>Total</td>
<td>41</td>
<td>36</td>
</tr>
<tr>
<td>Average ROP (m/day)</td>
<td>31</td>
<td>25</td>
</tr>
</tbody>
</table>

Table 1: Well A vs B Drilling Time Breakdown for 8.5" Section

Analysis of the drilling time breakdown suggests:
- Time spent in drilling (bit on bottom) is proportionate to the interval drilled.
- Time spent in tripping for bit / BHA changes is also proportionate to the interval drilled.
- Time spent in dealing with wellbore instability in Well A has been considerably reduced by almost 7 days as compared with Well B.
- Hole condition in Well A is much better as compared to well-B leading to much better quality log acquisition and formation evaluation.
  - Discounting for surface / downhole equipment failure, Well A has definitely been drilled more efficiently as compared to Well B

In 6" Section
By following the recommended mud weight in 6" section (Fig. 6) ONGC, Nazira was able to drill 542m section in 21 days approximately (Fig. 7). Reduction in wellbore instability issues has led to considerable reduction in time spent in reaming, mud circulation, cleaning tight spots etc. The wellbore is in a much better shape as can be seen from the caliper data in the 6" section across Kopili Formation from various offset wells (Fig. 8).
Analysis of the drilling time breakdown suggests:

- Stuck incident was encountered at X m due to shearing off of Drill pipe cross-over (mechanical failure).
- 6” section was sidetracked from Y m MD.
- During drilling the side-track section of the 6” hole, the pipe was stuck at Z m. This was released soon by pumping spotting fluid and working on the string.
- Mud weight used is close to recommendation which led to faster drilling
- Despite longer exposure time in the Kopili shale section very minor hole failure can be see and the hole is of good shape
- It took almost 21 days to drill 542 m at a rate of 25 m/day
- However drilling was stalled for longer duration due to frequent equipment failure which led to increase in NPT

![Figure 6: Well-A Post-drill wellbore stability analysis for 6” section](image)

![Figure 7: Well A Time vs Depth for 6” section](image)
Analysis of the drilling time breakdown suggests:

- A stuck incident was encountered at X m due to shearing off of the drill pipe cross-over (mechanical failure).
- A 6" section was sidetracked from Y m MD.
- During drilling the side-track section of the 6" hole, the pipe was stuck at Z m. This was released soon by pumping spotting fluid and working on the string.
- The mud weight used is close to the recommendation which led to faster drilling.
- Despite longer exposure time in the Kopili shale section, very minor hole failure can be seen, and the hole is of good shape.
- It took almost 21 days to drill 542 m at a rate of 25 m/day.
- However, drilling was stalled for a longer duration due to frequent equipment failure, which led to an increase in NPT.

Figure 6: Well-A Post-drill wellbore stability analysis for 6" section

Figure 7: Well A Time vs Depth for 6" section

Figure 8: Wellbore shape comparison

Additional investigation

Additionally, integrated analysis of advanced sonic and multi-arm caliper data provided a very valuable insight into the real cause of the various drilling events in the well. In LCM zone, the caliper showed one set of arms to be over-gauged and the arms perpendicular to it to be under-gauged. Direction of enlarged hole coincides with fast shear azimuth obtained by advanced sonic processing in this zone. Further analysis with Dipole Radial profiling and from changes in temperature log, it is evident that the well has crossed critically stressed fractures or faults which have slipped along the fracture plane (Fig. 9). The possible fractures / faults were found correlating with the faults identified in the regional basemap.

Figure 9: Well-A It is evident from combined analysis of failure criteria and caliper that some slippage has taken place along fault/failure plane
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![Figure 6: Well-A Post-drill wellbore stability analysis for 6” section](image1)

![Figure 7: Well A Time vs Depth for 6” section](image2)
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Acknowledgements

The authors thank ONGC for their support and permission to publish the paper.

References

Role of Well Log Conditioning using Multiple Regression Techniques for Petrophysical Analysis and Seismic Interpretation: A Case study of Cauvery Basin, India

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Keywords  Multiple linear Regression, Synthetic logs, Well - Seismic tie

Abstract

The recorded log data has very high resolution and can identify very fine different geological processes as compared to any other recorded data. But at the same time, during drilling process log data gets affected by borehole rugosity, invasion, mud cake formation, salinity, temperature & pressure etc. Sometimes the logs could be entirely missing or not usable due to bad hole conditions. The analysis made on such unreliable data may lead to wrong identification & estimation of litho fluid type. To avoid this data made to be prepared in such a way that the analysis become easier and reliable. Log data conditioning is a process which make raw data suitable for any kind of analysis. Synthetic logs need to be generated by suitable techniques which enable to fill the missing data gap. Once the data gap is filled necessary environmental corrections are applied along with the appropriate filter for spike and noise removal.

In this paper author has made an attempt to highlight the various issues related to the recorded log data and their effect on Processing & Interpretation. The data which is affected from the above mentioned effect has been corrected by applying proper environment correction as provided by services companies for their various logging tools. To reduce the noise level in the data appropriate filters has to be applied without missing the desire information of the formation. To fill the gap multiple regression techniques have been adopted by considering almost all the available logs. This statistical technique is a model based approach where the maximum correlation between the recorded and modeled log is estimated based upon the combination of the different logs.

Thus the data obtained after the conditioning is suitable for seismic interpretation and petrophysical analysis. The estimated petrophysical parameters i.e. clay volume, water saturation and effective porosity now become possible in the section where the log data were missing as well as where the density is affected due to borehole washout. This conditioned data is also suitable for seismic correlation, well to seismic tie and wavelet extraction etc.

Introduction

The objective of the petrophysical interpretation is to transform well log measurements into reservoir properties i.e. porosity, saturation, permeability, mineral component volumes etc. These parameters are responsible for oil/gas estimation and production. For determination of rock petrophysical properties an adequate logging suit is necessary which can measure the desired property accurately. Once the Petrophysical model has been fixed, it will be applied for estimation of the reservoir parameters i.e. Effective Porosity ($\Phi$), Water saturation ($Sw$) and Volume of Clay (VCL) using multi-mineral inverse
optimization technique. This technique takes into account the effect of conductive or nonconductive, heavy minerals, radioactive minerals and different clay contents reported in core studies. Resistivity log is the measurement of electrical properties of the formation with depth. The depth of investigation is up to 220cm depending upon the type of induction or electrical tools. These tools are less affected by the borehole environment. Sonic log is the measurement of the slowness of the acoustic wave within the formation with depth. It is highly affected by the borehole rugosity. Density log is the measurement of the bulk density of the formation with depth. Sonic and density logging tools have very small (< 12 inches) depth of investigation as compared to Resistivity tools Fig: 1(a). These two logs are heavily affected by borehole washout, rugosity and mud filtrate invasion. Density and sonic logs are used to estimate the porosity of the formation. In case if both the logs are affected by the borehole environment then they do not represent the true porosity and hence the true saturation, clay volume of the virgin formation at the well location Fig: 1(b).

The Area of study pertains to Ramnad sub basin situated in the south of Cauvery Basin in Indian Peninsula. Several numbers of wells have been drilled so far, out of which ten wells have been chosen for the log conditioning, quantitative petrophysical analysis and G&G interpretation. The general stratigraphy of the area Fig:2(a) shows five formations viz Bhuwanagiri, Kudavasal Shale, Nannilam, Portonovo shale and Kamlapuram and karaikal shale. The depth interval for the analysis has been chosen is from Kamlapuram to Bhuwanagiri formation. The missing interval of density-neutron logs are in portonova shale Fig: 2(b), some section of Kamlapuram formation Fig-and affected by bad bore hole in some part of Kamlapuram formation Fig-2(c).
Optimization technique. This technique takes into account the effect of conductive or nonconductive, heavy minerals, radioactive minerals and different clay contents reported in core studies.

Resistivity log is the measurement of electrical properties of the formation with depth. The depth of investigation is up to 220 cm depending upon the type of induction or electrical tools. These tools are less affected by the borehole environment.

Sonic log is the measurement of the slowness of the acoustic wave within the formation with depth. It is highly affected by the borehole rugosity.

Density log is the measurement of the bulk density of the formation with depth. Sonic and density logging tools have very small (<12 inches) depth of investigation as compared to Resistivity tools. Fig: 1(a).

These two logs are heavily affected by borehole washout, rugosity and mud filtrate invasion. Density and sonic logs are used to estimate the porosity of the formation. In case if both the logs are affected by the borehole environment then they do not represent the true porosity and hence the true saturation, clay volume of the virgin formation at the well location Fig: 1(b).

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Log Data Conditioning

Log conditioning includes the depth matching of logs with respect to resistivity log, splicing of log curves, editing of bad data, and elimination of spurious signals and creation of synthetic logs to fill the missing data. Synthetic logs have been generated using multiple Regression Techniques as shown in fig: 3(a) & 3(b). The multiple regression equation generated for density is as following.

\[
\text{RHOB} = 6.78904 -0.0462998*GR -0.0431175*DT -10.7619*\log_{10}(\text{ILD}) + 0.000450129*GR*DT + 0.103915*GR*\log_{10}(\text{ILD}) + 0.102687*DT*\log_{10}(\text{ILD}) -0.000975275*GR*DT*\log_{10}(\text{ILD}),
\]

The synthetic Log is generated with this equation having correlation coefficient of 0.75 with Sonic and Neutron log.

![Figure 2(b): Well- A; Missing log data of a formation](image1)

![Figure 2(c): Well- A; Bad hole in a clastic section](image2)

![Figure 3(a): Regression Equation generation (Well: A)](image3)
The multiple regression equation generated for neutron log is as following:

\[
\text{NPHI} = -1.7088 + 0.0177031 \times \text{GR} + 0.018978 \times \text{DT} + 5.98055 \times \log_{10}(\text{ILD}) - 0.000163836 \times \text{GR} \times \text{DT} - 0.0545787 \times \text{GR} \times \log_{10}(\text{ILD}) - 0.057259 \times \text{DT} \times \log_{10}(\text{ILD}) + 0.000501467 \times \text{GR} \times \text{DT} \times \log_{10}(\text{ILD})
\]

the synthetic log is generated with this equation having correlation coefficient of 0.73 with Sonic and Density log.

These multiple regression equation have been applied to the other wells where a good match was found between the recorded log and the synthetic logs.

![Figure 3(b): Synthetic log at missing interval (Well: A)](image)

The equation thus generated in well A was applied to create the synthetic log in perungulam area where already density log is recorded in the same formation and it is found good match with the recorded density log. Fig 4 (a)

![Figure 4(a): Synthetic density log generated (Well: C)](image)
The multiple regression equation generated for neutron log is as following:

\[ NPHI = -1.7088 + 0.0177031 \times GR + 0.018978 \times DT + 5.98055 \times \log_{10}(ILD) - 0.000163836 \times GR \times DT - 0.0545787 \times GR \times \log_{10}(ILD) - 0.057259 \times DT \times \log_{10}(ILD) + 0.000501467 \times GR \times DT \times \log_{10}(ILD) \]

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The equation thus generated in well A was applied to create the synthetic log in Perungulam area where already density log is recorded in the same formation and it is found good match with the recorded density log. Fig 4(a).

**Petrophysical Analysis**

A petrophysical model was developed to estimate the reservoir parameters of the formations. Multi-well Z-plots of Neutron-Density were generated to identify the constituting minerals within formation. Elan processing was done to estimate the petrophysical parameters viz effective porosity, water saturation and clay volume for seismic inversion study. The synthetic density log was used to estimate the petrophysical parameter in the missing section and the estimated petrophysical parameters were improved as well as showing as per the formation lithology. Fig 5(a).

The petrophysical parameters estimated in the bad bore hole section as shown in Fig- 6(a) red rectangular section is without log conditioning estimating unrealistic effective porosity around 50% and the quartz volume is more than 100%. Density neutron shows the shale character because of the bad hole effect whereas SP shows a good reservoir. The statistical model has been selected in the sand where the hole condition is good i.e. above the shale section as shown Fig-6(a). This selected model has been applied in affected reservoir below the shale section as shown in Fig-6(b) green rectangular section. After conditioning the density and neutron the realistic petrophysical parameters were estimated with effective porosity of 25-30%. These parameters are further used in as input in the seismic reservoir characterization.

![Figure 5(a): Processed output by synthetic logs (Well: A)](image)

![Figure 6(a): Processed output without log conditioning](image)
Conclusion

1. Log conditioning was performed on 17 wells of the Ramnad sub basin of Cauvery Basin in the south of Indian Peninsula. The work done on correction of density, neutron and sonic data within the reservoir in the field and for bad borehole rugosity effect. Log conditioning strategy was applied to the individual stratigraphic units.
2. To fill the density data gap a multiple regression technique was used to develop a relationship between sonic, resistivity, neutron and density data. That regression equation was used to create a synthetic density and neutron log in individual stratigraphic units.
3. The regression equation was used to create synthetic density log in other wells where density log is recorded and it is found good match with the recorded and the synthetic one.
4. Product from log condition will be used for seismic reservoir characterization to be done in the Ramnad area.
5. High tech logs such as Elemental Capture Spectroscopy, Nuclear Magnetic Resonance, Tensor resistivity, Borehole imaging and multi-pole Sonic along with conventional cores in few future wells will help for better understanding and reservoir characterization.

The views expressed in this paper are solely of the authors and do not necessarily reflect the view of ONGC.

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Petrophysical Rock Typing as A Tool for Carbonate Reservoir Characterization: A Case Study from NBP (D1) Field, Mumbai Offshore Basin, India

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Abstract

Reservoir characterization of highly heterogeneous carbonate reservoirs is fret with uncertainties, owing to fact that there are number of factors which control their reservoir properties, such as facies, depositional environment and diagenetic history. A multivariate petrophysical rock typing using GR, RHOB, NPHI and DT was developed by statistical data analysis and empirical observations to subdivide the complex carbonate rock bodies into discrete rock classes which are not only petrophysically significant but also geologically meaningful, with a genetic linkage. The linkage between the rock types and their petrophysical properties was established first through detailed facies analysis of cores, thin sections, SCAL and MICP study. The whole stratigraphic interval containing different pays is discretised into five rock classes viz.

(i) High Gamma, K and Th rich Shale (acts as regional cap rock)
(ii) High Gamma, uranium rich tight limestones (thin non-reservoirs acts as local cap rocks)
(iii) Low Gamma, tight limestones (thicker non-reservoirs, induces lateral reservoir heterogeneity and are the product of destructive diageneis of cleaner limestones by sparitisation and dolomitization)
(iv) Low Gamma, reservoir limestones (cleaner and porous limestones, primary porosity is either preserved or selectively enhanced by diageneis and leaching process, acts as good producers)
(v) Marginal reservoir (acts as baffles, either the depositional facies is dirtier or the porosity of cleaner facies is occluded through diageneis)

Through this approach substantial improvement in the understanding of the reservoir development of the (NBP) D1 field, Mumbai Offshore basin was achieved both in terms of lateral and vertical variability of reservoir properties. Vertical compartmentalisation of the reservoir is caused by transgressive shales and high gamma tight limestones whereas the lateral heterogeneity is caused by the diagenetically induced tight limestone.

Introduction

The D1 field is an offshore oil field around 200 km from the mainland at a water depth of ~85-90m, located to the east of the Miocene shelf edge in DCS area, south-west of Mumbai High. Structurally, it is a NW-SE trending doubly plunging anticline. Established hydrocarbon bearing zones belong to Panvel Formation of Oligocene and Ratnagiri Formation of Miocene age (Figure1). Reservoirs are very heterogeneous and thin in nature alternating with tight carbonate layers. Seismically it is a carbonate buildup developed on the Oligocene shelf edge, locally forming a rimmed platform; core and well log study indicate that it internally constitutes of number of shallowing up cycles. Each cycle starts with mudstone-wackstone facies and grades to packstone-granestone, occasionally capped by the boundstone facies. Frequent exposure at the end of the cycle is also evident, followed by marine flooding and deposition of another cycle. In this article we are presenting an approach which is simple and effective to discriminate reservoirs from non-reservoirs and attach a genetic connotation to each rock type for better reservoir predictability and modeling.

Methodology

The methodology includes detailed facies analysis of the entire drilled section to establish linkage between the rock types and their petrophysical parameters. Depositional processes were inferred through facies analysis and a depositional model was constructed. The workflow consisted of:
i. Lithological interpretation from well log, core and cutting
ii. Microfacies identification from cores and cuttings and thin sections, following (Dunham, 1962)
iii. Cross-plotting RHOB and NPHI with microfacies
iv. Establishing the relationship between the core derived porosity, permeability, pore-throat radius (MICP data) and their petrophysical parameters such as RHOB, NPHI, GR, DT, following (Ebanks et al., 1992)
v. Classification/discretization of entire drilled section into number of petrophysically significant rock types

Results

It was observed that overall a positive correlation exists between cleanliness of facies and porosity, in general the cleaner the facies better the porosity except in diagenetically altered zones. As per the convention, the cleanness of the limestone is inversely related with the gamma ray values, lesser the gamma ray count cleaner the limestone and vice-versa. However, cross-plots NPHI vs. RHOB (porosity/density logs) with the microfacies show considerable overlap (Figure 2) between the different microfacies and their petrophysical parameters (porosity and density). Dirtier facies (wackstone-mudstone) were mostly tight but the cleaner facies (packstone-grainstone and sometimes boundstone) were also found to be tight, thin section study reveals that porosity of cleaner facies were deteriorated because of pervasive dolomitization and sparitisation.

There are all together five rock types exist:
(i)High Gamma Shale (HGR-Shale)
(ii)High Gamma tight limestones (HGR-Tight Limestone)
(iii)Low Gamma tight limestones (LGR-Tight Limestone; non-reservoirs)
(iv)Low Gamma reservoir limestones (LGR-Reservoir Limestone)
(i)Marginal reservoir

Two major classes of high gamma picks were noticed, Type: 1 (HGR-Shale) associated with shale (high K & Th) and Type: 2 (HGR-Tight Limestone) associated with tight limestone (high uranium), recognised using the spectral gamma ray log signatures. High gamma tight limestones were also distinguishable from the shale by the lower NPHI values, which typically ranges between 0.05 to 0.1, RHOB values between 2.5 to 2.65 and DT ranges between 52-65, where as in the case of the shale the NPHI is greater than 0.25 and RHOB ranges from 2.04 to 2.5, DT varies between 70 to 140.

Low Gamma Reservoir (LGR-Reservoir) class is mostly represented by the cleaner limestone (gamma ray <50), NPHI ranges between 0.1 to 0.28, RHOB between 2.10 to 2.5 and DT ranges between 70 to 84, typically more than 70.

Low Gamma Non-reservoir (LGR-Tight limestones), is represented by limestones which are cleaner in nature (low gamma count; ranges between 17-50, typically < 50) but does not have the porosity, NPHI value is in the range of 0.02 to 0.1 and the RHOB values ranges between 2.5 to 2.65, DT ranges between 52-65 and does not act as reservoir, it is interpreted to be the product of diagenetic alteration, wherein cleaner limestone has undergone the diagenetic process and got negatively impacted leading to the deterioration of the reservoir property.

It was also observed that the ranges of different petrophysical values varies between different stratigraphic interval from top to bottom, which correspond to upper, middle and lower pays. Accordingly different range of cut-offs on petrophysical parameters were applied on different pays and a discrete rock class log was generated for all the hydrocarbon pay intervals. Figure 3 shows different discrete petrophysical rock types, their log signatures and core properties.
Conclusions

Petrophysical rock typing of carbonate reservoirs is an effective tool not only to discriminate reservoirs from non-reservoirs but also to establish a genetic linkage with the depositional and diagenetic processes. Complexities of these reservoirs are the result of multiple cycles of diagenetic overprinting on original depositional facies. Facies predictability (vertical and lateral) drastically improves when the petrophysical rock types are seen in combination with the depositional and diagenetic model. HGR shales and the HGR Limestone constitute laterally extensive seals, and acting as Flow Zones boundaries, whereas LGR-Reservoir class is the major producing reservoirs. LGR-Non-reservoir class is the product of diagenetic alteration of cleaner limestone and induces lateral reservoir heterogeneity. Marginal reservoir class acts as baffle and impedes the flow.

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Acknowledgements

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Figure 1: Location map of the Bombay offshore basin, study area is marked with red rectangle (a) and stratigraphy of the area (b).
**Figure 2:** Cross-plot of NPHI/RHOB, coloured with microfacies in Z-scale, do not show any consistent relationship and there is considerable overlap between the different microfacies and their petrophysical parameters (porosity and density).

**Figure 3:** Discrete petrophysical rock types, well logs and the calibrated cores. GR in the 1st track (blue), RT in red, RHOB –NPHI in blue and brown. PIGN and SUWI are colour filled. Discrete petrophysical rock types are shown in the last track, cored intervals with the recovery percentage are plotted alongside.
Abstract

GS-13 sand of Gandhar field is a heterogeneous clastic reservoir and kind of unconventional in nature containing huge amount of siderite and little amount of Goethite as heavy mineral. Kaolinite is present as clay mineral. Capillary pressure studies carried out on core samples of one well is showing around 90% capillary bound water and 98% pores are micro-pore (1<1μm). Since GS-13 has poor reservoir facies with high porosity and very low permeability (as evident from core study), producibility is very low. As such in Gandhar field hydrocarbons are mostly accumulated in the multiple sand units GS-1 to GS-12, from bottom to top, belonging to Hazad member of Ankleshwar formation of Middle Eocene age. GS-13 is the only hydrocarbon bearing sand developed in Ardol Formation just above Kanwa shale which separates GS-13 from Hazad formation. Cross-sections/correlation profiles of different wells were generated to understand the spread of GS-13 sand across the field and variation of log characteristics in different directions. Electro-facies characterization and STM analysis is carried out using facimage module in GEOLOG for GS-13 sand unit of Gandhar field. Electrofacies characterization is one of the best solution to overcome the problem of heterogeneity in determining petrophysical properties of reservoir and identify producing zones. In this regard, in first step Multi-resolution graph-based clustering (MRGC) technique is applied. It is a multi-dimensional dot pattern recognition method which is based on non-parametric K-nearest neighbor and graph data representation. For model building purpose, key wells are identified based on production data and other supporting data. MRGC technique is applied on the key wells to build electro-facies model using basic logs. Kernel representative index is applied in finalizing optimum number of clusters. 8 clusters/Electrofacies are finalized for GS-13 sand. Multi-well log data coherence characterization using the Similarity Threshold Method (STM) is carried out next on logs of all the wells to find out similar facies (similar to modelled producing facies) based on which, key wells are identified for petrophysical evaluation. Petrophysical evaluation of key wells which is selected based on similarity analysis result is carried out incorporating XRD analysis results and computed porosity is then compared with NMR porosity.

Introduction

Gandhar is a major oil and gas field spreading over 800 sq. km. in the Jambusar-Broach block of Cambay Basin. The field has developed in the western flank of Broach depression, which lies between Dadhar River in the north and Narmada River in the south. The hydrocarbons are mostly accumulated in the multiple sand units GS-1 to GS-12, from bottom to top, belonging to Hazad member of Ankleshwar formation of Middle Eocene age. GS-13 sand is developed just above Kanwa shale which separates GS-13 and Hazad formation. GS-13 is the only hydrocarbon bearing sand developed in Ardol Formation. So far in Gandhar GS-13 pay 6 wells has been tested. Among them only two wells, GNDR-A and GNDR-B have produced oil. The wells GNDR-C and D produced little oil/traces of oil and wells GNDR-E and F showed poor influx. In view of the above, our aim was identification of suitable wells for testing and preparation of geological model. GS-13 is developed in around 275 wells in this area. Our aim is adapt suitable and fast method to find out suitable wells for testing. Well logs can clustered as Electrofacies. In this study MRGC method is used for Electrofacies modelling of producing wells and this model is propagated using STM method throughout the field that contains 275 wells. GEOLOG software is used for applying MRGC and STM analysis in this study.
Data clustering and concept of MRGC

In mature basins, the task of an explorationist is becoming increasingly complex because of the unconventional nature of the remaining resources. To develop a comprehensive understanding of reservoir distribution and characteristics, large volume of data is required to be analyzed. Besides, in unconventional reservoirs, often characterized by complex mineralogy and low permeability, it is really challenging to interpret well log data and identify potential reservoirs using conventional log data analysis. To understand the reservoir behavior, knowledge of various facies in the reservoir is essential. An electro-facies is a class defined by a unique set of log responses. The log signature of a given electro-facies indicate the physical and chemical properties of the rock and fluid contained within. Electro-facies are generally used to predict the variation of lithology from well logs, in order to better predict the reservoir heterogeneity. The selection of log data and the definition of electro-facies are optimized for characterizing the rock type.

The name clustering indicates the problem of detection of clusters from a data set where a prior data structure is unknown. Different clustering methods exist and Multi-resolution graph-based clustering (MRGC) is a non-parametric method. It is a combination of KNN and graph data representation techniques. Data is analyzed and different groups of data are formed. These data groups may be of different density, size, shape and relative separation. MRGC automatically determines the optimal number of clusters but it also allows geoscientists to change clusters/properties to define the Electrofacies. (Shin-Ju, Y. and Rabiller, Ph. 2000)

Optimal number of clusters can easily be identified by individual as well as automatically for data set which have well separated clusters. The optimal number of clusters is a function resolution the user would like to analyze. Utilizing the neighboring index to determine a KNN-attraction for each point small facies groups are formed. At last, the small clusters are merged to get final clusters. (Shin-Ju, Y. and Rabiller, Ph. 2000)

Similarity Threshold Method: Multi-well log data coherence characterization

Similarity of the key wells to the rest of the data sets decides whether the model can be successfully propagated to all other wells. Model calibration in one or more wells is the key to any interpretational
method for field studies. The Similarity Threshold Method (STM) is a technique used for checking the similarity of two logged intervals.

This method which depends on the k-nearest neighbors theory integrates all log data and characterizes the lithological response of the reference intervals in ‘n’ dimensions log space. Comparison is done between the application data sets and the reference set for each depth level and a decision rule have to be applied to determine whether the depth level can be represented by the reference set. It integrates reject concept (Dubuisson, 1990) in the classification process and it also allow to define a degree of similarity between the data sets.

As introduced by Chabuel H T, Veillerette A, Rabiller P, 1997, STM similarity analysis can be done in two stages. In the first stage, an n-dimensional space where n is the number of logs and the shape of the learning set which characterize the domains around each observation are defined. These domains are built by searching for the k nearest neighbors of the points. The domain data set forms an acceptance class, Ca. In the second phase, each observation in the application set and a degree of membership to the Ca, acceptance class are defined. A decision rule is applied to discriminate different acceptance class. The observations which are far, in terms of distance, from points in the learning set are grouped in a reject membership class, Cd. (Red color in STM template). The observations which are close to the points of the learning set can be included in several domains and are classified in Ca (Green color in STM template). The observations which are not too far, in terms of distance, from learning points, but they can be included under no other domain. These observations are classified in the ambiguity reject class Co (Yellow color in STM template). The degree of membership and the assignment to classes can be represented as logs: the Membership Degree log MD and the Similarity Threshold log ST.

Before implementing an interpretation model field wide, STM method may be applied as a preliminary process to check the coherence of the data.

**Electrofacies modelling and similarity analysis using STM-Field application**

Electro-facies characterization and STM analysis is carried out using facimage module in GEOLOG for GS-13 sand unit of Gandhar field. As such hydrocarbons are mostly accumulated in the multiple sand units GS-1 to GS-12, from bottom to top, belonging to Hazad member of Ankleshwar formation of Middle Eocene age. GS-13 is the only hydrocarbon bearing sand developed in Ardol Formation just above Kanwa shale which separates GS-13 from Hazad formation.

GS-13 sand is a clastic formation. This sand is a kind of unconventional reservoir containing huge amount of siderite and little amount of Goethite as heavy mineral. Kaolinite is present as clay mineral.

Only two wells, GNDR-A and GNDR-B have produced oil from this sand. Few other wells were also tested but produced traces of oil/showed no influx. General producing facies of GS-13 sand is characterized by Resistivity around 7-12 ohm.m, density around 2.6-2.8 g/cc and neutron around 0.40-0.60 P.U. General log motif of producing and non-producing/water bearing wells are presented in figure no.2-5.

The present study deals with a relook of well logs and sees the prospectivity of GS-13 sand in the entire field. For developing the model, key wells are identified based on production data and log characteristics. Modelling is carried out in two steps. GR, RHOB and NPHI are used as inputs of the model. In first stage, for characterizing electro-facies without considering the real litho-facies, number of clusters of the well logs was determined on trial and error basis. In second step, resistivity log was incorporated in the model to discriminate potentiality of a well. To finalize the model and to differentiate pay from non-pay zone, different cut off values for input logs are used. Cut off values are selected from log characteristic of different tested wells (both producing and non-producing wells) and also from core data. In this study, two different set of clusters are generated –set of 6 and 8. Different Clusters of set 6 and 8 are shown in fig.6 and 7 and comparison of two set of Electrofacies is shown in figure no. 8. As the set of 8 clusters captures maximum facies, model with 8 predefined clusters is selected as the optimum model with the best result. This model is then propagated through the well using KNN method and each facies is assigned a number and also color by the software itself.
After finalizing Electro-facies model of hydrocarbon bearing zone, similarity analysis is carried out for all the wells in the field. Similarity modelling is used to assess coherence on application dataset. Similarity analysis results can be grouped into three classes based on degree of acceptance. With higher degree of acceptance, the data set is classified as similar and in STM template, it is represented by green color. With fair degree of acceptance, the data set is classified as ambiguous and it is represented by yellow color. With low degree of acceptance, the data set is classified as dissimilar/rejected class and it is represented by red color (Fig. 9 and 10). Similarity is analyzed level by level and results are displayed as a log in depth representation and the result is validated with another producing well GNDR-D. It shows the well is similar to that of producing wells GNDR-A and GNDR-B. The result is shown in figure no. 9. The results of similarity analysis are shown in fig. 10.

Based on results of similarity analysis carried out on 275 wells, 35 wells are selected for petrophysical evaluation. Processed output of GNDR-A and GNDR-B are presented in Figure no. 11 and 12 respectively. Obtained effective porosity from ELAN is comparable to that of NMR 3ms porosity and core data.

**Conclusion**

MRGC technique is very useful in data clustering. Electrofacies characterization using well logs is successfully done using MRGC. Similarity threshold method is very effective tool to check consistency between different data sets i.e. it is helpful in identifying intervals with similar characteristics. Using this method, pay zones are differentiated from non-pay zone and it can give result very fast (few minutes). From these identified intervals, processing can be carried out only on selected wells which appear to have developed good reservoir facies and finally the potentiality of these intervals can be assessed. In our study, 35 wells were separated out of 275 wells.

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8. Study material of Geolog Facimage module and training manual.

**Figure 2:** Log motif of GNDR-A. It produced oil

**Figure 3:** Log motif of GNDR-B. It produced oil

**Figure 4:** Log motif of GNDR-X. GS-13 is water bearing

**Figure 5:** Log motif of GNDR-Y. GS-13 is water bearing
Figure 6: Above figure shows different clusters and electro facies analysis of cluster of 6

Figure 7: Above figure shows different clusters and electro facies analysis of cluster of 8
Figure 6: Above figure shows different clusters and electro facies analysis of cluster of 6

Figure 7: Above figure shows different clusters and electro facies analysis of cluster of 8

Figure 8: Comparison of two sets of Electrofacies model (Cluster of 6 and 8)

Figure 9: Validation of model. GNDR-A and B produced oil. Right most figure is showing GNDR-D is similar to that of GNDR-A and GNDR-B. On testing, GNDR-D produced oil.
Abstract

Drilling for hydrocarbons nowadays equates to drilling deeper into extreme environments. This in practical terms, for the everyday reservoir engineer, the driller, the geologist, means very well designed mud systems and high hydrostatic pressures. The mud system plays a very important if not crucial role in terms of keeping formation fluids in place as well as avoiding damage to the formation in extreme environments.

Despite the obvious disadvantages/issues stemming from high hydrostatic pressures (formation damage, sticking risks, high solids content, etc.), one of the least thought off issues and many times the most important, is the one that concerns tight, depleted/low pressure reservoirs.

The issue is quite simple in its nature but difficult to solve. It goes hand in hand with Formation Testers and it is the following: High hydrostatic pressure mud systems create high overbalances which in turn pose limitations on drawdowns for Formation Testers. If the overbalance in the well, is quite high, which will usually be the case in wells over 3000m deep, this will most likely restrict the formation tester ability to record any reservoir pressures (i.e. to go below reservoir pressure). In simple terms this means that the differential pressure that can be reached by the formation tester, in order to "see the real reservoir pressure, is limited by mechanical strength limitations imposed on the operating parts, i.e. Packers, Probes, Pumps.

Simply put, in high overbalanced wells, the formation tester will not be able to see low pressure reservoir sections and will completely miss the existence of depleted reservoir zones.

In addition to this, is unconventional reservoirs (extremely tight formations), where the high pressure differential created by attempting to flow reservoir fluid, will prohibit the use of any current/traditional formation testing tools.

This paper will present such case and discuss the advantages of using a new technology formation tester designed with high differentials in mind. This applies to high hydrostatic mud systems, tight to extremely tight formations and also depleted reservoirs. Being designed to withstand extremely high differential pressures, the tool is suited to extreme logging conditions and tight reservoir sections.
Discovery of a Bypassed Depleted Reservoir Sections in High Overbalanced Wells with the Use of the New Reservoir Formation Tester Technology

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Abstract

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This paper will present such case and discuss the advantages of using a new technology formation tester designed with high differentials in mind. This applies to high hydrostatic mud systems, tight to extremely tight formations and also depleted reservoirs. Being designed to withstand extremely high differential pressures, the tool is suited to extreme logging conditions and tight reservoir sections.
Introduction

The term depleted reservoir is used to describe a reservoir that has an unexpected low reservoir pressure compared to normal lithostatic pressure gradients. This pressure loss is sometimes due to offset production from near wells in heavily developed basins, the low pressure can also be found in virgin reservoirs, in the case of exploration drilling, where the reservoir preserves its original pressure regime in a perfect closed system, then a geological, sedimentological or structural event occurs leading to a change in reservoir position and depth.

The ability to recognize symptoms of depletion becomes crucial to proper reserves evaluation and adequate completion decision and interpretation of reservoir continuity between wells.

Wireline Formation Testing technique has been used since 1950 as part of reservoir characterization in conjunction with other techniques such as log interpretation, core analysis, and well testing. The objective from running a formation tester depends on the well type, it can go from simply measuring reservoir pressure in a development well to manage the depletion program to – in the case of exploration well – discover the existence of hydrocarbon, identify the formation fluid type and fluid contacts (from pressure gradient and downhole fluid analysis) as well as some other feature that the formation tester can offer (i.e. mini-DST, stress test and microfrac, etc.).

The formation testers constitute a large family of modules that are combined together to form a complete tool string especially designed for a specific drilling and/or logging condition. In the case of high overbalanced depleted reservoir, the present technology has some limitation on the maximum differential pressure that can be imposed on the various mechanical parts, and cannot be overcome unless a new tool is innovatively designed to perform in this extreme environments. This tool has now became reality and has proven its unique value in reservoir characterization.

This paper will present the operation of a formation tester in two completely different environments, with two different technologies: Old technology which showcases an Extra Large Diameter Probe and new technology which showcases a 3D Radial Probe.

Wireline Formation Tester Standard Probe modules vs 3D Radial Probe module

A probe module (see figure 1) is mainly used (traditional application for a probe) to measure reservoir pressure. It provides the necessary conduit for the fluid to come from the reservoir into the tool. The probe can also be used to conduct detailed reservoir characterization, by conducting Mini-DSTs, Reservoir Fluid Identification and Reservoir Fluid sampling, but to do so it needs permeable formations.

Figure 1: Single Probe Module
Types of Single Probe Modules

Now since the Single Probe Module is normally used in all types of environments and since the pressure differential during a test or sampling depends – amongst other things – on the area of flow,

$$\frac{Q \times \mu}{k \times A}$$

the probes comes in different flow area sizes; small, large and extra-large. The two probes shown in Figure 2, and the substantial increase in the flow area between the two can be clearly seen.

![Figure 2: Small and Extra Large Probes](image)

Figure 2a, presents a clear distinction in terms of % increase of flow area between traditional technology tools, used on a daily basis for formation characterization and testing.

![Figure 2a: A clear comparison between Conventional Technologies in terms of flow areas](image)

The way these different probe sizes are used, is very simple. Small diameter probes are used in very permeable formations and extra-large diameter probes are used in lower permeability formations. So far so good, but the problem starts when the permeability drops to low values. That is when the differential pressure on the probe becomes too large for the tool to withstand. So what needs to be done is to increase the flow area a lot more. This is when the Dual inflatable Packer comes in.
Dual Packer

The Dual Packer is an inflatable packer (see figure 3) that offers a very substantial increase in flow area compared to the Probes mentioned earlier. The increase in area offered by the Dual Packer (packer from now on) is in excess of 1200%.

The packer is mainly used in tight formation, where the probes are restricted due to high pressure differentials imposed by the tightness of the formation as well as the small flow area of the probes (compared to the packer). Once again the Dual Packer, like the probes, is also restricted by high pressure differentials. The pressure difference between the upper/lower surface area of the Dual Packer and the inside of the packer can destroy the tool if it exceeds certain pressure limits. This usually happens when transiting from tight reservoir sections to unconventional, extremely tight reservoirs. Despite the massive area increase, the pressure limits do not allow the Dual Packer to operate in such environments.

This is where the new technology comes in. This new technology is the 3D Radial Probe

3D Radial Probe

The idea behind this new tool is simple enough but hard to execute. The design involves the “merging” of 2 old technologies into one.

These old technologies are the Probe and the Dual Packer modules. By the merging of these two different designs the 3D Radial Probe emerged (see Figure 4).
The 3D Radial Probe was designed with extreme environments in mind. As such the tool operates in both extreme and good permeability reservoirs, in low and high hydrostatic environments. The picture in Figure 5, shows the actual tool

![Figure 4: Merging of Probe and Dual Packer Technologies](image)

The design of our new radial probe offers 500 times increase in probe surface area compared to standard probe placing it as the industry's largest total surface flow area with 79.44in², this feature allows sampling in a wide permeability range extending down to 0.01mD, it is also critical in measuring pressure and/or fluid sampling in heavy oil or near-critical fluids, unconsolidated formations, thinly laminated formations and rugose and unstable boreholes.

Beside the flow area, the new generation of radial probe can handle 8000psi differential pressure rating qualified between flowline and hydrostatic pressures, this allows a successful application in highly overbalanced and/or depleted reservoir.

![Figure 5: The actual 3D Radial Probe as seen after a job](image)

![Figure 6: Standards Probe vs New Generation of 3D Radial Probe](image)
Case Study Job Execution

Originally the toolstring contained the traditional, basic extra-large diameter probe as the customer did not expect any surprises in terms of reservoir quality (mobility and pressures) (see Figure 7).

The string also contained two fluid analyzers (compositional and basic) for advanced fluid identification/compositional purposes.

The program was as follows:

a) A pressure survey to be done first so as to profile the formation in terms of mobilities and reservoir pressures.

b) Based solemnly on the mobilities, pick sampling/fluid ID station depths.

c) POOH once all objectives done.

Twenty three (23) pressure tests were performed (for pressures and mobilities) out of which 65% were tights. The rest of the 35%, were in the range of ~10mD/cP with only 2 tests with mobilities higher than 100mD/cP+.

An example of the tights tests can be clearly seen in figure 7, with an overview in figure 8.

7: High pressure differentials seen in tight tests performed. The stair case signature is typical of dry tests

As seen in the above figures the pretest exhibits a stair case signature, clearly showing a non-existent response from the formation and with every test done the pressure heads towards zero.

Figure 8: An overview of typical tight test. The maximum DP on the tool is clearly seen
Since the flowing pressure keeps dropping with every single test done, the absolute pressure seen by the tool, is also increasing. This exposes the tool to an increasing pressure differential until any further testing on the formation will result in damaging the tool. This is where the physical limit of the tool is reached and therefore cannot provide any further information on the reservoir pressure, and renders any further formation analysis, an impossibility.

This is where the new technology comes to the rescue.

As already discussed the 3D Radial Probe was designed with extreme environments in mind. This also applies to high overbalanced formations.

As shown in Figure 9, if the formation pressure is assumed to be at values lower than what the probe is capable of going down to, the reservoir will be missed and most likely assumed Tight or Dry.

![Figure 9: An “assumed” reservoir pressure of 4000psia and probe differential limits](image)

This is exactly what happened in the job described here. Some of the tested reservoir sections were differentially depleted, something unknown to customer since this was an exploration environment.

Thus the real reservoir pressure – as discovered later by the 3D Radial Probe – was much lower than what the probe could withstand in terms of differential pressures.

Since the actual results – depleted reservoir sections – were not know even after the completion of the 1st run, a second run was put together with the objective of re-investigating the same depths performed by the probe, but this time the 3D Radial Probe was used instead.

This gave the engineers and clients an advantage of 8000psia limit. In other words the pretest could go from a hydrostatic pressure of 8000psia down to 0psia flowing pressure. This in turn meant that any depleted reservoir sections lower than the maximum probe limit, would be easily “seen” by the 3D Radial Probe. Same thing applied in tight reservoir sections with formations too tight for sampling and/or reservoir fluid analysis, using traditional technology.
Figure 10 (Extra Large Diameter probe) reveals an extremely tight reservoir of 0.1mD/cP mobility, with no certain reservoir pressure and potentially dry, i.e. response from reservoir is non-existent.

Figure 11 shows the 3D Radial Probe at the same depth, conducting a fluid analysis station for approximately 4 hours without any difficulties and/or limitations in terms of the differential pressure created. The 3D Radial Probe verified a depleted but very high mobility reservoir, close to ½ Darcy (thus the reason for being depleted).

Hardware mechanical limitations was the main reason for these 2 different results, and without the use of new technology, i.e. the 3D Radial Probe, these depleted reservoir sections would have been totally missed.

In addition to reservoir pressure, the use of downhole fluid analyzers helps identifying the reservoir fluid being gas condensate, samples were successfully captured.
One thing to note here is the high hydrostatic pressure used, which adds to the problems of depleted or tight reservoirs.

Now going from high hydrostatic depleted reservoirs to high hydrostatic extremely tight reservoirs the limitations remain the same and that is mechanical (strength) limitations of traditional tools.

Figure 11 shows the case (same job) where the formation is extremely tight. This in combination with high hydrostatic pressure, makes sampling and/or fluid identification of reservoir fluid by the traditional Extra Large Diameter probe, an impossibility.

Figure 10 (Extra Large Diameter probe) reveals an extremely tight reservoir of 0.1mD/cP mobility, with no certain reservoir pressure and potentially dry, i.e. response from reservoir is non-existent.

Figure 11 shows the 3D Radial Probe at the same depth, conducting a fluid analysis station for approximately 4 hours without any difficulties and/or limitations in terms of the differential pressure created. The 3D Radial Probe verified a depleted but very high mobility reservoir, close to ½ Darcy (thus the reason for being depleted).

Hardware mechanical limitations was the main reason for these 2 different results, and without the use of new technology, i.e. the 3D Radial Probe, these depleted reservoir sections would have been totally missed.

In addition to reservoir pressure, the use of downhole fluid analyzers helps identifying the reservoir fluid being gas condensate, samples were successfully captured.

One thing to note here is the high hydrostatic pressure used, which adds to the problems of depleted or tight reservoirs.

Now going from high hydrostatic depleted reservoirs to high hydrostatic extremely tight reservoirs the limitations remain the same and that is mechanical (strength) limitations of traditional tools.

Figure 11 shows the case (same job) where the formation is extremely tight. This in combination with high hydrostatic pressure, makes sampling and/or fluid identification of reservoir fluid by the traditional Extra Large Diameter probe, an impossibility.

Figure 10: XLD Probe shows a tight reservoir with a possible pressure of 4600psia.

Figure 11: Extra Large Diameter probe pretest shows an extremely tight reservoir (0.02mD/cP)

The Chances of conducting any type of detailed fluid analysis in such environment with the probe, are non-existent.

The same station was attempted with the 3D Radial Probe (Figure 12) and despite the extremely low mobility (0.02mD/cP) an identification of the reservoir fluid was successfully completed without any issue (traces of water seen, no sample was taken as per client request).

Figure 11: Extra Large Diameter probe pretest shows an extremely tight reservoir (0.02mD/cP)

The same station was attempted with the 3D Radial Probe (Figure 12) and despite the extremely low mobility (0.02mD/cP) an identification of the reservoir fluid was successfully completed without any issue (traces of water seen, no sample was taken as per client request).

Figure 12: Tight reservoir. Same as Figure 11 but station performed with the 3D Radial Probe. The fluid identification of the reservoir fluid was done successfully @ 0.02mD/cP, despite the high pressure differential.
Results and Discussion

As already discussed in this case the job was performed in 2 runs; the 1st run was with traditional technology – an Extra Large Diameter probe. The 2nd run was with new technology – the 3D Radial Probe.

The reason for this was the expectation that the reservoir quality would have been good enough to allow complete pressures and fluid identification/sampling with basic technology, thus minimizing well logging costs.

This (as seen), turned out to be impossible with traditional technology (Extra Large Diameter probe) due to 3 main factors; a) High Hydrostatic Pressure, b) Extremely tight reservoir sections and c) depleted reservoir sections. The use of new technology enabled the client to complete all objectives. Without the use of the 3D Radial Probe, all of the depleted reservoir sections, would have been missed and the identification of the reservoir fluids in the extremely tight reservoir sections, would have been impossible. It is worth noting here that had a Dual Packer been used to conduct these tests (instead of the 3D Radial Probe) the same limitations (in terms of differential pressure) as the traditional probe modules, would have applied.

Conclusion

The use of new technology gave the customer a completely different picture from what was expected. This enabled the client to change well strategies accordingly and complete the well successfully.

The use of new technology has made the testing of nonconventional reservoirs, a reality.

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References


A Novel Approach for NMR Based Enhanced Rock-typing for Delineating Potential Reservoir Facies: A Case Study

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Keywords Rock typing, Heterogeneous Rock Analysis, Nuclear Magnetic Resonance, Factor Analysis

Summary

Conventional approaches for delineating reservoir facies might not always lead to the best results, especially, when the reservoirs are complex and challenging. Alternative approaches have become a necessity to address these challenges and rock typing is one of those. Unconventional methods of facies characterization using heterogeneous rock analysis technique has been used in this case study to address the challenges of rock typing for complex reservoirs. In addition, NMR Factor Analysis has been integrated to demonstrate value to this study.

Introduction

Fields in offshore Kutch and Saurashtra in the western part of India have become important for oil and gas exploration in recent times. Several exploratory wells has been drilled in these blocks, where gas reservoirs were found both in clastics and carbonate formations. Main gas bearing formations in those wells were Nakhtaran (Late Palaeocene), Jakhau (Early Eocene) and Chhasra (Mid Miocene) formations. Specific challenges encountered by most of these wells in those formations were due to reservoir heterogeneity.

In the present paper, we discussed a case study on an alternative approach for rock typing to address the challenges of such reservoir heterogeneity and to correlate similar zones based on this analysis across multiple wells in the field.

Theory and Methodology

Heterogeneous rock analysis (HRA), a log-based rock classification method has been utilized for the integration of core data and correlation of core data to log domain in unconventional reservoirs. HRA defines rock classes based on their fundamental attributes of texture and composition as discriminated by log inputs. HRA identifies consistent data structures, defined initially by unsupervised pattern recognition of the input data channels (for example, well logs). The resulting patterns have a unique meaning in texture and composition space. This defines the development of a reference model, which is the first step commonly known as facies clustering. By extension, the properties correlated to the rock classes are then transferrable to non-cored wells or sections via linear discriminant analysis, even if not directly solvable through other deterministic or inversion models of the logs themselves. This defines the second step and is known as facies tagging.

In addition, NMR Factor Analysis (NMR-FA) was introduced to answer fluid properties of the reservoir. NMR-FA helps in extracting maximum information from multi-dimensional NMR data. The workflow used provides improved accuracy and efficiency in determining poro-fluid distributions and associated porosities in conventional as well as unconventional reservoirs.

In general, NMR-FA technique addresses perennial questions concerning:

- How many poro-fluid components the T2 distribution truly represents
- Characteristics, identification and volumes of these components
- Distribution of the component volumes that affect bound/free fluid T2 cutoff, poro-fluid facies classification, and capillary-height conversion

NMR-FA is applicable to both wireline and LWD acquisition.
NMR-FA has the following five activities:
- Factor Analysis and Clustering
- Bad-hole/Undesirable Facies Identification and removal
- Sorting External Petrophysical Data by Poro-fluid Facies
- Pseudo-Capillary Pressure and Saturation Height Modeling by Poro-Fluid Facies
- Customization of Results - Names, Colors and Palettes – based on User Interpretation

Results

The present case study is from four wells located in an offshore field of Kutch-Saurashtra. The wells are vertical and drilled with water-based mud. Conventional and advanced open-hole logs were acquired using wireline tools. HRA analysis was performed to identify prospective zones which were not observed in the conventional petrophysical approach. HRA clustering results in the key well indicated several zones which could have been used for reservoir sampling and would have reduced the rig time (Figure 1). The results were validated with three other wells in the same field and hence can give us more confidence for predicting prospective zones in any future wells (Figure 2). Further, NMR-FA analysis validated the clustering results generated by HRA. In some zones, NMR-FA provided better value addition as it helped in distinguishing different flow units in the same sand reservoir. This was again validated by grain-size analysis which clearly showed that the zones in purple color are dominated by finer grain-sized particles while the zones in blue are dominated by courser grain-sized particles (Figure 3).

Discussions and Conclusions

With the focus of oil and gas industry shifting towards more challenging and complex reservoirs, it requires new approach and technique to characterize these heterogeneous units. HRA clustering and tagging methods are one of the unique methods to approach such a solution. Many prospective zones have been identified using this analysis which could have been used for quick decision making such as optimizing pre-test sampling points. It also helps in predicting reservoirs responses in any upcoming wells in the same field. NMR-FA has also validated the results from HRA. In many formations, it has added more value by distinguishing the reservoir into many poro-perm units, which has again been validated by the grain-size distribution. Integrated workflows of HRA and NMR-FA can be utilized to obtain meaningful solutions for tight or complex reservoirs.

Acknowledgements

The Authors would like to express their gratefulness to Oil & Natural Gas Corporation Ltd. for the permission to present the data.

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Figure 1: This figure demonstrates the application of HRA analysis for optimizing sampling points. The black points in the last track indicate Tight Seal (sampling points) while the orange points indicates Good Test. Sampling was carried out in Zone A and Zone C. Zone A has produced Gas while Zone C had all tight seals. The results show that Zone B could have been a potential zone as it falls in the same HRA class as Zone A.

Figure 2A: This figure shows the integration of different logs and analysis results. The depth scale and key parameters are clearly indicated.

Figure 2B: Another detailed view of the reservoir analysis, showing the various layers and their respective properties.
Figure 2A, 2B, 2C: These figures demonstrate the application of HRA analysis other wells in the same field (HRA tagging). The black points in the last track indicate tight seal (pretest sampling points), the orange points indicates good test, the blue points indicates water and the red points indicates gas. All the good points, water and gas zones have been attributed to a particular HRA class while the tight and lost seals have been attributed a different color.

Figure 3A, 3B: These figures demonstrate the HRA and NMR-FA results value addition for rock typing. Track 11 displays the HRA class to a single rock type for the entire sand interval. Track 10 displays the pretest sampling results. Orange color indicates good test while the blue color indicates water. Track 12 displays the NMR-FA results which explains that the sand is not a homogeneous body, but is divided into many different poro-perm units based on the color coding. This NMR-FA result is validated by grain size distribution which explains that the zones in purple color are dominated by finer grain sized particles while the zones in blue are dominated by courser grain sized particles.
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