

Characterization of an Unconventional Complex Clastic Reservoir through Log & Core Data to Facilitate Future Exploration and Development Activities leading to Production Augmentation - A Case Study

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Abstract

The reservoir in this study lies in the Cambay basin of Western onshore India. Unlike other prolific reservoirs in this basin, this reservoir has poor characteristics due to presence of thick sideritic shale, thin carbonaceous laminae, thinly laminated siltstone and very fine grained sandstone reservoir facies with thin shale laminations. In general the porosity development is poor due to higher argillaceous contents and also destruction due to sideritization and precipitation of authigenic clays. The permeability of the reservoir is towards lower side and as a result, most of the wells need hydro-fracturing for activation.

The conventional approach of identifying the reservoir quality from logs does not apply in this reservoir due to its complex nature. The complexity can be gauged from the fact that more than ten minerals have been reported in these fields by various core studies. Therefore innovative techniques have been drawn to identify facies based on Gamma Ray-Deep Resistivity Overlay, Neutron-Density separation, SP and CMR logs. The facies thus identified are validated by testing results, permeability, core capillary pressure and flow-unit data.

As it is impossible to solve for volumes of all the existing mineral with only conventional logs, an innovative approach with quartz, clay and aggregate of secondary minerals has been adopted for the quantifications of the volumes through ElanPlus. The output results of Elan are validated with the available core data and also with effective porosity of CMR log, wherever available.

The main outcome of the study is identification of the suitable areas for the drain hole placement, prospective areas for future exploratory / development activities and existing stress direction orientation based on FMI orthogonal caliper break out analysis. In view of this analysis, horizontal drain-holes are recommended to be placed in North-South direction (along minimum stress direction) and hydro-fracturing jobs in conventional wells are suggested in East-West direction (along maximum stress direction) to enhance the oil productivity.

Introduction

The fields of Sadra, Mahelaj and Naika, which are the area of our present work, are located in the Ahmedabad – Mehsana block of Cambay Basin. These fields are on the north westerly rising flank of Tarapur depression, believed to be the kitchen of the hydrocarbon generation in this basin. The other fields adjoining the area of our study are Nandej, Nawagam, Dholka and Wasna. These fields along with the fields under study have seen an accelerated exploration and production activities over the period of time due to their proximity to the source of hydrocarbon generation. A number of pays at various stratigraphic levels have been discovered in these fields which include pays in deeper Olpad, Cambay Shale and Kalol Formation. In the area of study, however, the reservoir development is seen only in Kalol- IX and X of Sertha member.

Since the time they were discovered in the year 2000 and put on commercial production in the year 2002, the production profile of the fields is not very encouraging and the wells are not performing to the extent envisaged. The underperformance of these wells may be attributed to poor characteristics of these reservoirs having thick sideritic shale, thin carbonaceous laminae, thinly laminated siltstone and very fine grained sandstone reservoir facies with thin shale laminations. In general the porosity development is poor due to higher argillaceous contents and also destruction due to sideritization and precipitation of authigenic clays. In some part of the reservoir, however, the laminated siltstone-sandstone has moderate to good intergranular porosity, leading to hydrocarbon accumulation. The presence of micropores along with argillaceous and carbonaceous material in the matrix has also got a damaging effect on the dynamic properties of the reservoir. The permeability of the reservoir in general is towards lower side and as a consequence, most of the wells needed hydro-fracturing for activation.

A comprehensive formation evaluation of all the 23 wells has been carried out during this work. As stated earlier, the reservoir has got a very complex mineralogy and more than ten minerals have been reported in the various core reports of the wells. Since enough relevant tools (equations) to solve for these minerals are not available, an aggregate of minerals approach have been considered for data processing. The mineral parameters have been arrived at by cross plot technique. All the available data including data from new-tech tools like CMR and FMI have been used for evaluation. The available well-wise core data have been integrated to validate the Elan answers. The electrical parameters a, m and n have also been picked up from core reports.

An attempt has been made to characterize the reservoir on the basis of available log data. This has been done by two methods, namely facies mapping and property mapping. For facies map, good facies have been identified based on log characteristics like resistivity-gamma ray overlay, neutron-density separation and SP log responses. This profiling has been carried out with the help of environmentally corrected raw logs in the dip and strike directions to know the lateral extension of different facies. The property map, on the other hand, has been prepared on the basis of processed results wherein the hydrocarbon interval thickness of different wells has been mapped to know the lateral extension of prolific units. Both these methods are corroborative.

Finally describe the technique of oriented perforation for optimizing the hydro-fracturing job. This technique is prevalent in the industry and also being practiced in ONGC. The concept of hydro-fracturing in the direction of maximum stress has gained popularity in recent times owing to its success in arresting sand production, reducing the fluid flow tortuosity near the borehole and channelizing the fracture energy in the right direction to look deeper into the formation, thus enhancing the producibility of the reservoir. The direction of maximum stress is identified on the basis of breakouts seen on 4-arm calliper of FMI logs. The possibility of placing horizontal wells as an alternate completion strategy has also been worked out. Additionally, prospective hydrocarbon potential areas have been indicated for K-IX & K-X pay zones.

Methodology & Results

Identification of good facies

Identification reservoir facies for facies mapping has been done with the help of Gamma ray and deep resistivity overlay. Well-wise overlay of Gamma Ray with deep resistivity is drawn in such a manner that against correlatable marine shale (present between K-IX & K-X) both the curves coincide as shown in track-2 of Figure-1. This facilitates facies identification. Against good facies excellent anti-correlation is observed because in these reservoirs Gamma Ray will be low as compared to shaly facies whereas the resistivity will be high. The reason for high resistivity is the presence of hydrocarbon wherever the reservoir is developed (it may be noted that there is no water bearing layer present in these fields). Therefore resistivity against such reservoir will also be higher than that against shaly formations. A resistivity cut-off greater than 4.0 to 4.5 ohm-m has been

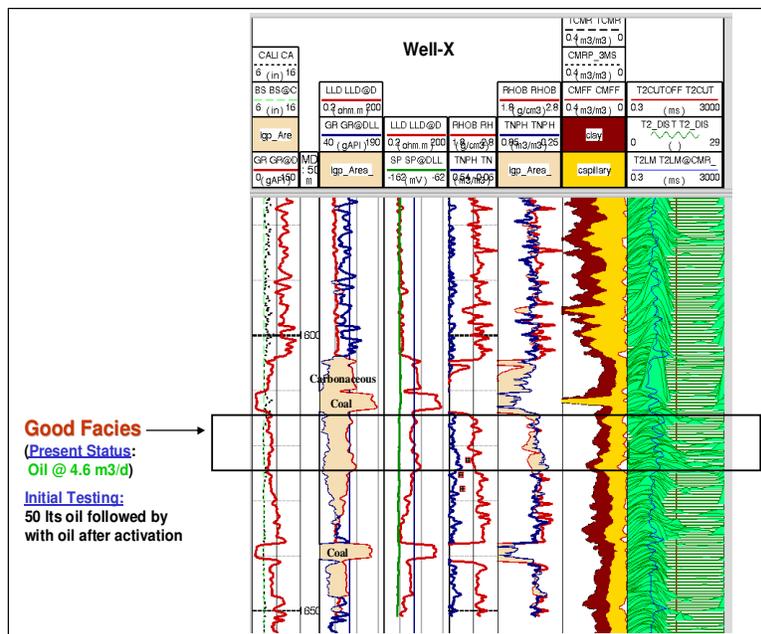


Figure-1 : Facies identification through well logs

fixed for good facies depending upon porosity value. But in most of the cases, resistivity value of 4.5 ohm-m has been found more suitable. For this purpose a constant line of 4.5 ohm-m resistivity value has been drawn in track-2. The reason for choosing this resistivity cut off is based on the initial testing / production data analysis which indicate good producibility above this cut off. In addition to gamma ray – deep resistivity overlay, lower gamma ray value (track-1), small neutron density separation (track-4) and good SP development (track-3) have also been considered as attributes for good facies. The example of good facies developed is shown in well-X (Figure-1), whereas the example of moderate to poor facies is shown in well -Y (Figure-2).

Further an overlay of RhoB & PhiN was also added in track-5, scaled in such a way that both the curves overlay in the shale layers. In this overlay PhiN scale has been taken as 0.25 to 0.85 against the RhoB scale of 2.8 to 1.8. By this overlay a distinct hydrocarbon type crossover anomaly is observed against the earlier interpreted good facies (Figure-1, track-5) which otherwise is not seen on the conventional limestone compatible scale (track-4). This anomalous behaviour is missing in the well-Y (Figure-2) as in this well only moderate to poor facies is developed.

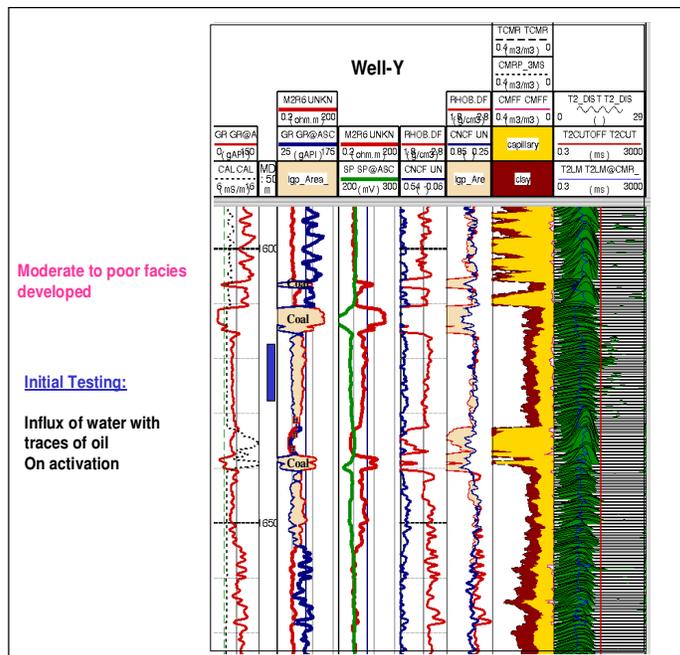


Figure-2 : Facies identification through well logs

The validation of the interpreted good facies has also been attempted with help of CMR data, testing data, permeability information from SFT/core, flow units seen in cores and capillary pressure data. As can be seen in Figure-1 the CMR T₂ distribution in well-X shows more free fluid porosity (CMFF, track-6) and T₂ decay time indicating slower decaying of protons (track-7) as compared to well-Y (Figure-2) where moderate to poor facies is developed. Initial testing data also indicates the facies developed in well-X to be good as compared to well-Y because well-X flowed oil whereas well-Y gave only influx of water with traces of oil on activation.

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Fixing of Mineral Parameters

As discussed earlier the horizons K-IX and K-X are characterized by complex lithology. More than ten minerals have been reported by various core studies. Since sufficient relevant tools (equations) are not available to solve for these minerals, an approach with quartz, clay and aggregate of secondary minerals have been adopted for the quantifications of the volumes through ElanPlus module of Geoframe.

For fixation of minerals parameters RhoB-PhiN cross-plots have been

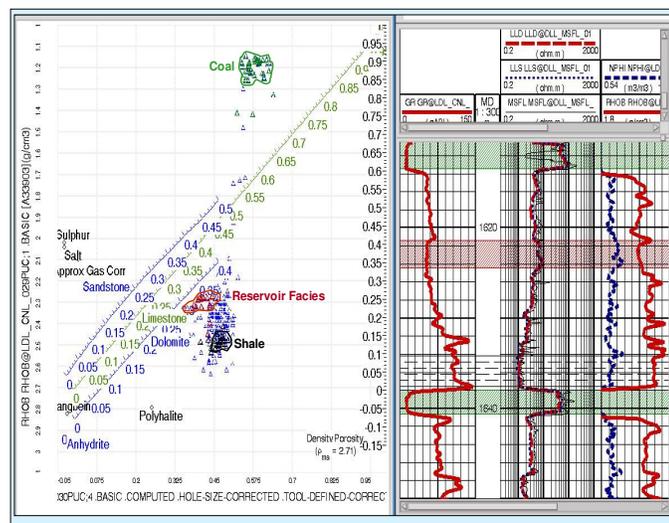


Figure-3 : RhoB Vs PhiN Cross Plot indicating Different Types of Lithology (Well-X)

prepared (one example is shown as Figure-3) for number of wells covering entire study. Facies were differentiated as Reservoir, Shale, Coal and Carbonaceous based on their position in cross plot and respective log motifs. These well-wise facies from various wells were pooled to a composite RhoB–PhiN cross-plot (Figure-4) representing the entire study area. The composite cross-plot shows different clusters for Reservoir facies, Shale, Carbonaceous and Coal regime distinctly representing the entire study area.

For fixation of various minerals following approach have been adopted:

- Quartz can be fixed as per its standard log tool response ($RhoB = 2.65$, $PhiN = -0.06$).
- As per core studies of number of wells, the clay is defined as the mixture of Kaolinite and Chlorite. Hence a line was drawn joining Kaolinite to Chlorite points. From analysis of logs best shale is developed in the well shown in Figure-3. The Shale point of this well is shown in the composite cross-plot.

However for fixation of clay point, the shale point was corrected for carbonaceous effect (reducing density value) and the point was brought vertically down to Kaolinite – Chlorite line. This was done because the core reports suggest that shale contains a lot of carbonaceous material, which in turn affects density measurement very strongly. However neutron porosity value for clay and carbonaceous material are of similar order.

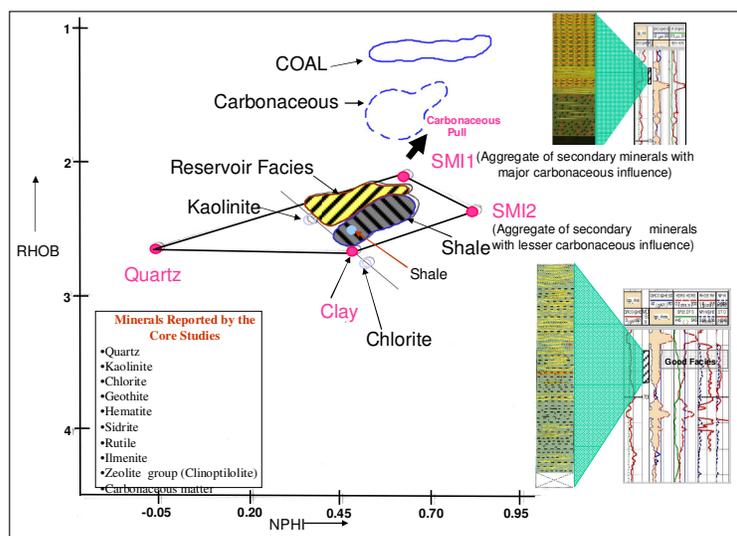


Figure 4 : Composite RhoB Vs PhiN Crossplot

Therefore clay point was fixed ($RhoB = 2.7$, $PhiN = 0.48$) between Kaolinite – Chlorite line as shown in the composite cross-plot (Figure-4).

- For aggregate of secondary minerals an envelope was drawn from quartz point towards reservoir facies and a point was fixed below to carbonaceous cluster at SMI1 position. SMI1 is defined as aggregate of secondary minerals with major carbonaceous influence and is positioned closer to carbonaceous facies in the composite plot.
- Two more envelopes were drawn, one from clay point and another from SMI1 point, honouring the reservoir and shale clusters. These enveloped lines meet at SMI2 position. SMI2 is defined as aggregate of secondary minerals with lesser carbonaceous influence. In this aggregate plenty of carbonaceous material has been replaced by weathered iron minerals like Geothite ($PhiN = 60+$) which is deposited under oxidizing conditions. That is the reason for $PhiN$ of SMI2 to be on the higher side. $RhoB$ of SMI2 is also higher as compared to SMI1 because it contains less volume of carbonaceous matter.

For fixing SMI1 & SMI2 lots of permutation and combinations

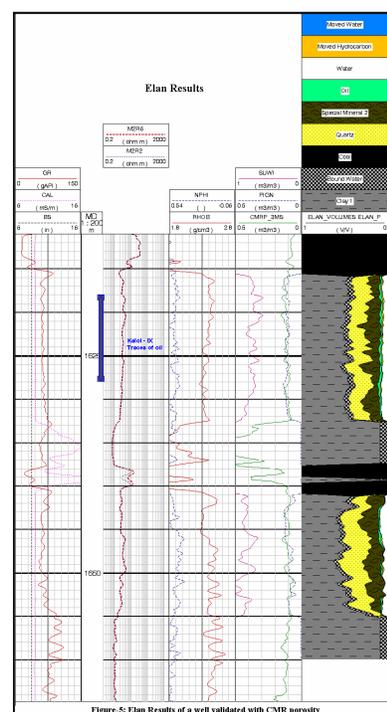


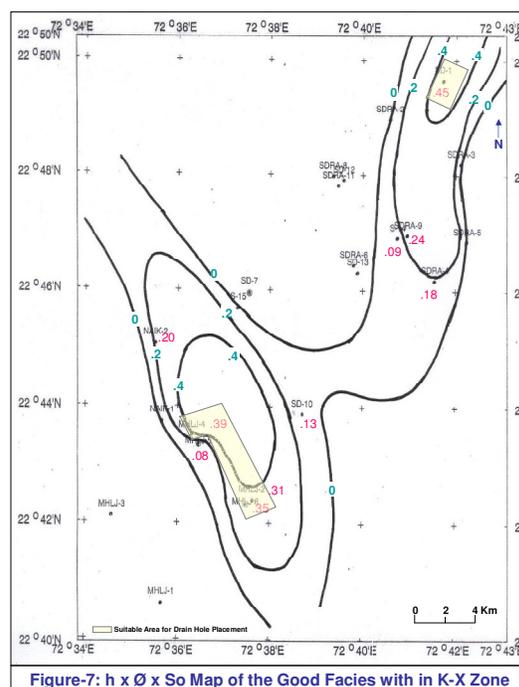
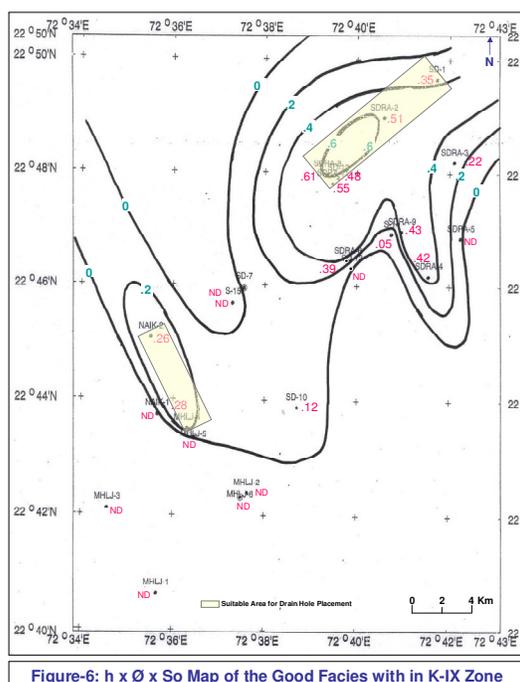
Figure 5: Eln Results of a well validated with CMR porosity

were carried out and these points were fixed after visualizing best processing quality results (SDR curve) and best match between ELAN out put with the available core data.

The processed results of all the wells with the above parameters have been validated with different external information like core, testing results, hi-tech logs, etc. wherever available. Figure-5 shows the processed result of one of such wells where the Elan porosity is compared with clay-free effective porosity from CMR.

Mapping of properties and identification of prospective areas

The Good facies identified by the techniques described above have been mapped for K-IX and K-X pay zones by preparing structural contour map on the top of Good facies. Similarly the petrophysical evaluation in terms of porosity, saturation, permeability and NTG have been used to prepare maps of Integrated hydrocarbons meters ($h \cdot \phi \cdot S_o$), pay thickness, porosity distribution and permeability distribution. Two of these maps, one each for K-IX and K-X are shown in Figures-6 & 7.



Based on these maps some areas which hold potential for future exploration and development have been identified. For example the shaded areas in the Figure-6 & 7 have been identified for horizontal well placement in the respective pays. Likewise areas for exploratory leads have also been indicated.

Hydro-fracturing in Maximum Stress Direction

It has been observed that majority of the wells in these fields required hydrofracturing job for activation. The reason for this appears to be the poor petrophysical character of the reservoir having very low permeability. The core studies carried out in some of the wells exhibit an average permeability less than 20 md.

In the conventional type of hydraulic fracturing the zone is perforated in all directions without any consideration of stress directions. The perforations which happen to be in the direction of maximum horizontal stress or PFP offer least resistance during fracturing treatment. This generates optimal fracture initiation, fracture propagation and fracture geometry – width, length, height and conductivity. As a result the efficiency and effectiveness of reservoir stimulation treatments are improved and there is no near well-bore flow restriction. On the other hand, perforations not aligned with PFP tend to produce complex flow paths near well-bore during fracturing treatment. Fluids and proppants exit the well-bore, and then turn in the formation to align with the PFP. This ‘tortuosity’

causes additional friction and pressure drops, which in turn increase pumping requirements and limit fracture width. This will also increase formation break-down which will subsequently result into excessive sand production.

The above discussion brings us to the conclusion that an oriented perforation in the direction of maximum stress improves the efficacy of reservoir stimulation treatments and generates fractures with optimal properties. Therefore, if the in-situ stress magnitudes and directions are determined, the completion engineers may design perforating strategies for oriented fracturing that target the PFP direction.

One of the ways to ascertain the maximum stress direction is to look for breakouts on X-Y caliper, which occur in the minimum stress direction. Two of the wells do show breakouts on the orthogonal calipers of FMI logs (Figure-8). The relative bearing of Pad-1 on both the logs indicates that the breakouts are appearing in the N-S direction which essentially is the direction of minimum stress. This implies that the direction of maximum stress is E-W and this is the PFP in our case. Thus we conclude that if we carry out oriented perforations in E-W direction for hydraulic fracture treatment in the upcoming wells of these fields, probably we will achieve optimized fracturing and better production.

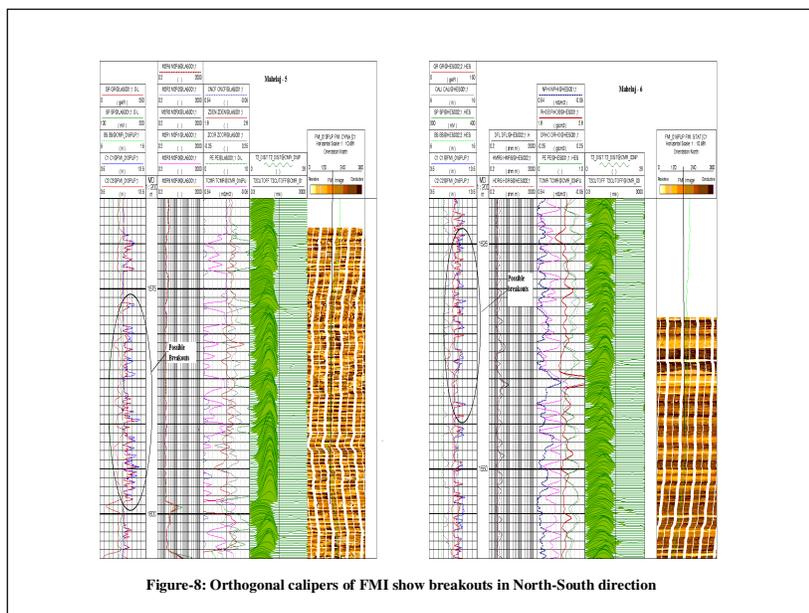


Figure-8: Orthogonal calipers of FMI show breakouts in North-South direction

Conclusions

- Innovative log overlay technique has helped in identifying good facies which otherwise are not easily identifiable.
- Concept of 'aggregate of minerals' has worked well in a multi-mineral scenario having only basic tools for Elan processing.
- Petrophysical property mapping of the field has indicated areas where development and exploratory leads can be taken.
- Occurrence of breakouts indicates the presence of stress anisotropy and hence hydrofracturing in PFP can be undertaken with the help of oriented perforation.

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