Rock Physics Modeling utilizing Saturation Height Function for Resource Assessment in Gas Reservoir of Giant Offshore Field in Western India

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Summary

In the present study, a fine scale static model for free gas clastic reservoir Z-1 in Miocene sequence of Western Offshore Basin has been made based on 3D seismic volumes, petrophysical and geological data. Reservoir simulation was then carried out on the geomodel with saturation distribution utilizing Saturation Height Function based on in-house petrophysical laboratory data.

The current workflow applied in reservoir simulation incorporating better rock physics model critically impacts well performance and reduces bias in model forecasts. It helps in realistic resource assessment for future development of this large gas reservoir in Mumbai High.

Introduction

The giant oil and gas offshore field of Mumbai High is situated in the western continental shelf area of India (Fig.1) and was discovered in the year 1974 and put on production in 1976. Lower and Middle Miocene limestone pack is the major oil bearing reservoir with STOIIP of about 1600 MMt. Free gas reservoir Z-1 under study is a clastic unit within the prolific oil bearing limestone pack. This clastic unit represents a minor regressive event within an overall transgressive phase during the post L-III deposition in Mumbai High. The clastic supply is attributed to the destruction of paleo Narmada-Tapti delta and redistribution of the detritus thus derived in a shallow marine environment under moderate energy conditions over a paleotopographic high. Reservoir facies of Z-1 sand consists of two litho-facies viz. clean sandstone and siltstone. It becomes shaly towards the western flank of Mumbai High. Both the sandstone and siltstone on testing have produced gas.

Z-1 reservoir is being exploited from 2 blocks viz. A and B and is on production since May-92. About 25 conventional inclined wells historically produced at a peak gas rate of about 5 MMSCMD (Fig.2). Current gas production rate is about 3 MMm^3/d (~30 wells) with recovery of about 45% considering GIIP of 50 BCM.

Figure-1 Location Map

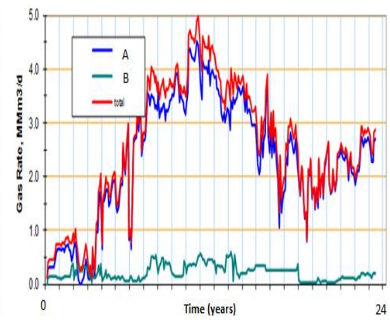

Figure-2 Reservoir Performance

Methodology

<u>Geo-Cellular Modeling</u>

A fine scale Geo-cellular Model (GCM) was made utilizing additional geological and petro physical data acquired through drilling of new wells. The depth map was prepared from 3D seismic interpretation for the whole seismic volume within the reservoir section. A total of about 430 processed logs were used in order to populate property throughout the model. The fine scale geo-cellular model for Z-1 sand was subdivided into 48 layers. To capture the important flow units the four zones of S-1 were divided into (48): 2, 15, 25, 6 proportional sub-layers respectively. Petro-physical parameters obtained from the log processing were used for property modeling.

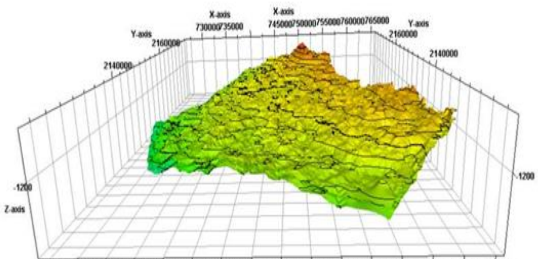

Figure-3 Top and Bottom of Z-1 Sand

Facies modeling workflow consists of data analysis for up-scaled facies logs and populating the facies throughout the model grid. Based on the raw logs and processed log data, three facies were identified as follows: Shale Facies code 0 (Pign <0.05), Sandstone Facies code 1 (Pign >0.08) and Siltstone Facies code 2 (Pign >0.05). Data analysis was carried out for all the three facies i.e. sandstone, Siltstone and Shale for all the four zones. The distribution so obtained was used for the facies modeling.

For porosity/saturation modelling, a stochastic model based on the Sequential Gaussian Simulation was generated using the upscaled logs. Data analysis was carried out on the upscaled Effective-porosity (PIGN) and Saturation (SUWI) logs. Using the variogram results obtained from data analysis, properties were populated throughout the model. While performing QC on the property population, layer wise 2D maps were prepared in order to verify areal distribution of model porosity vis-à-vis water saturation

The fine scale geological model has brought out the heterogeneity and structural disposition of sand geometry/reservoir facies leading to better reservoir characterization (Fig-4) in the entire area.

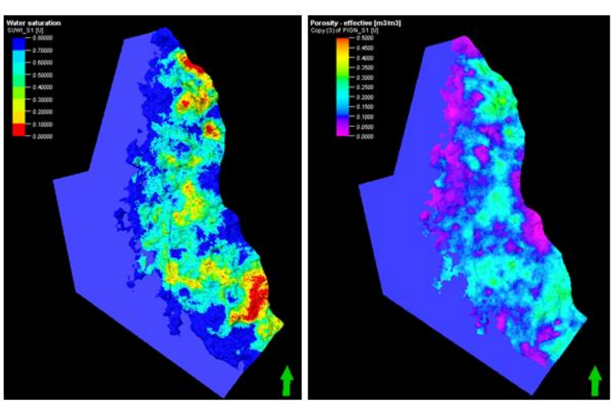

Figure-4 Saturation and Porosity Distribution of Z-1 Sand

Reservoir Simulation

GCM was upscaled aerially to 100x100 m grid size in order to reduce the number of cells in the model keeping in mind the in-built heterogeneity in sand distribution. The upscaled grid consists of 391x582x48 layers. Further, properties like Porosity and NTG were upscaled by volume weighted averaging method. The histogram analysis of upscaled & fine scale porosity show good correlation.

It was observed that in few areas, the saturation distribution was on a conservative scale which was mainly due to absence of processed logs and consequent property propagation algorithm.

Hence, cut-offs for porosity was revisited and changed from existing 0.08 to 0.05 to define net pay intervals. Shaled out areas and corrections in porosity were further incorporated for better representation of sand geometry. Considering Material Balance volume estimates of about 50 BCM (vis-à-vis static model volume of about 45 BCM) and for more realistic spatial distribution of saturation (with observed well deliverability), it was felt prudent to propagate saturation using Saturation Height Function (SHF) approach.

Initial reservoir pressure was considered to be 141 bar at datum depth (1229m: GWC) for initialization. For fluid modeling, based on gas composition, Formation Volume Factor (Bg) was considered to be 0.0086 v/v. Water viscosity, Formation Volume Factor and Compressibility have been considered as 0.274 cp, 1.031 v/v and 4.81e-5 1/bar respectively. Gas density taken in the fluid model is 0.796 kg/m^3.

Rock Physics Modeling: Workflow

Conventional core studies on Z-1 cores indicate that average porosity and permeability values of Z-1 sand to be about 30% and >100 md respectively indicating good reservoir facies.

Capillary pressure studies done in-house on the core samples of few wells were used to generate saturation height transforms as detailed below:

i) Laboratory capillary pressure (Pc) and saturation data were corrected to reservoir conditions. Pc distribution among the core samples seem to be in good agreement.

Rock Physics Modeling using Saturation Height Function for Resource Assessment

ii) Subsequently, normalized Pc curve (J-function) and normalized saturation function (Swn) relationship was obtained to represent saturation distribution in the entire Z-1 pack. Following equation was used to calculate J function from capillary pressure data.

$$J = \frac{0.218P_c}{\sigma \cos\theta}\sqrt{\frac{k}{\phi}}$$

Swn was calculated to improve the generality and degree of correlation. It is given by:

$$S_{wn} = \frac{S_w - S_{wir}}{1 - S_{wir}}$$

iii) Using cross plot of J function and Swn, the correlation obtained by least-square method is as below:

$$J = 0.0859Swn^{-1.097}$$

iv) A representative correlation between RQI (Rock Quality Index) and irreducible water saturation with a correlation coefficient of 0.9 was obtained (Fig.5) with equation as:

$$Swir = 0.0615RQI^{-0.507}$$

Where,

$$RQI = 0.0314\sqrt{k/\phi}$$

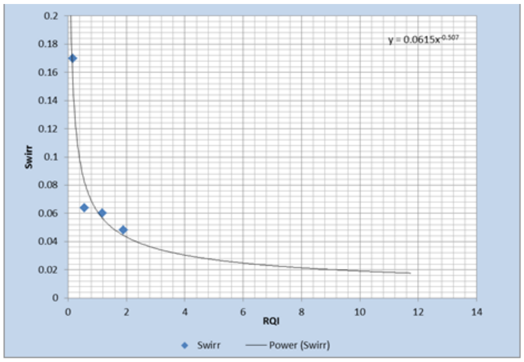

Figure-5 Irreducible Water Saturation Vs. RQI

Finally, water saturation was de-normalized using the Swn equation mentioned above. This is the initial water saturation distributed in the model.

Further, the above J function and saturation correlation was validated by comparing the saturation computed from processed logs as shown in Figure-6.

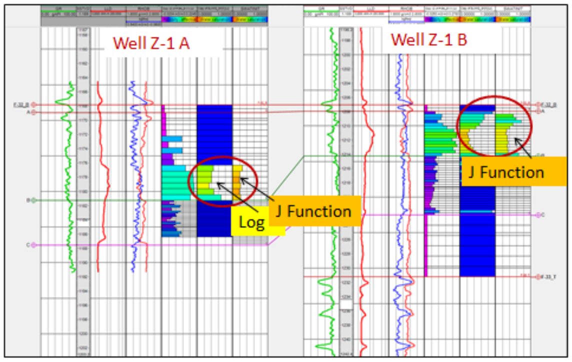

Figure-6 Validation of saturation distribution (J-Fn Vs. Log)

"Brooks and Corey" equation for gas-water relative permeability system was used to generate relative permeability curves from capillary pressure data. In the present case, Swn vs. Pc curve was generated using core sample data.

For Permeability Modeling, both the well test data and conventional core analysis data of wells were initially used to generate a ϕ-k relation. The relationship is shown below:

$$k = 28822\phi^{4.0658}$$

After achieving the gravity-capillary equilibrium, the model was used for history match.

For pressure match, historical production over the last 25 years was considered with Static/Buildup/FTHP pressure measurements considered as the main criteria for the match. Static Pressures were checked for consistency at datum depth. End point scaling of relative permeability curves were done with Swc (critical water saturation) considered in the model to be about 19%.

It is observed that at field/well level, a good history match is obtained with no cut in gas rates. Further, the average model pressure at the end of history match is about 86 bar. In the material balance (MB) estimates, volume weighted average reservoir pressure was calculated to be about 89 bars which corroborates well with model calculated pressure.

History matched model indicates in place gas volume of about 50 BCM which now matches well with MB estimates. The history match performance on field level is given in Figures-7.

Figure-7 History Match of Z-1 Simulation Model

Resource Assessment

Based on history matched model, several forecast runs were made under different boundary conditions keeping a THP constraint of 40 bars.

Optimized variant indicates additional gas production potential of about 12 BCM over a period of 15 years with anticipated recovery close to 70%.

Conclusions

Saturation Height Function (SHF) has been used to propagate saturation in the prepared Geo-cellular Model. Given workflow of Rock Physics modeling using J function for saturation distribution is now RQI dependent.

Considering reservoir heterogeneity and large extent (>500 km^2) of the reservoir, above methodology provides better spatial distribution of saturation and overcomes possible bias due to log processing issues and absence of well control.

Simulation model in-place volume is close to 50 BCM which is in good agreement with Material Balance estimates.

With good history match, simulation forecast runs indicates gas recovery of close to 70% over a period of 15 years with additional gas production potential of about 12 BCM.

In conclusion, the paper describes the methodology adopted in utilizing capillary pressure data into saturation height functions for saturation modeling which helps in reducing uncertainty in model predictability and resource assessment.

References

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