Uncertainty Analysis of Lower Barmer Hill Unconventional Play Storage Model

Aastha[1], Ajit Kumar Sahoo[*2], Bodapati S. Naidu[2], Utpalendu Kuila[2], Soumen Dasgupta[2], Arpita Mandal[2], Premananda Mishra[2]
1. Indian Institute of Technology, Khargpur
2. Cairn-Vedanta Oil and Gas Ltd
Email: ajitkumar.sahoo@cairnindia.comL

Keywords

Shale Play, Sensitivity, Storage Model

Summary

The Lower Barmer Hill (LBH) Formation of Eocene age is the major regional source rock in Barmer Basin of Rajasthan. It is considered to be a potential shale play due to its higher thickness, better organic richness and optimum thermal maturity. In our earlier work, an attempt was made to estimate the storage capacity of this play which resulted into 6-13 MMBOE/Km2. In the current work, we have attempted to change some of the important input parameters based on alternate understanding and evaluate the sensitivity of the storage model of LBH. The input parameters like source rock thickness, original total organic content (TOCo), and depositional hydrogen index (HIo) maps are updated and finally, the storage model for LBH is re-estimated. Out of the three updated input parameters, source rock thickness came up as the most sensitive parameter and raised the storage capacity of LBH within the kitchen areas by ~97%. This study has guided us to further work on thickness assumptions and acquire some more geochemical data in the specific part of the basin.

Introduction

The success of an unconventional hydrocarbon play strongly dependent on geochemical factors such as organic matter richness, type of kerogen, burial history of the basin and thermal maturity. A detailed description of organic geochemistry of the source rocks in the Barmer Basin is described in Farrimond *et. al.* (2015), while the detailed petroleum system modeling workflow including burial & thermal history, hydrocarbon generation and migration modeling is detailed in Naidu *et. al.* (2017). We only summarize here to capture the key geochemical parameters critical to evaluate an unconventional resource play potential.

The Lower Barmer Hill (LBH) Formation of Eocene age is the major regional source rock in Barmer basin of Rajasthan. Although multiple source rocks are present in the Barmer basin, the oil-source correlations from the discovered fields show that the Barmer Hill source rock is the major hydrocarbon contributor in entire basin (Dutta et. al, 2019). Organic richness and composition based on the Rock-Eval pyrolysis data from the drilled wells suggest oil prone algal Type-I kerogen in the northern part of the basin, where the Hydrogen Index (HI) goes up to 900 mg HC/g TOC with up to 14% TOC. In the southern kitchens, mixed type I and III kerogens with HI up to 400 mg HC/g TOC and TOC measurements up to 6-8% are observed. This variation in organic content, kerogen type and source facies is controlled by lake levels, depositional environment and paleo-geographic changes during Lower Barmer Hill transgressive event (Naidu *et. al.*, 2017; Dolson et. al., 2015). Its considerable thickness, higher organic richness and optimum thermal maturity (VRo up to 1.7%) makes it a potential unconventional shale play.

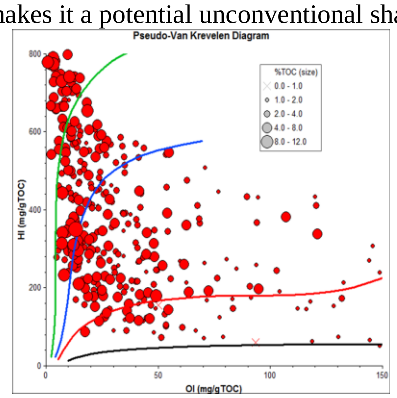

Figure-1: Pseudo-van Krevelen plot (modified from Farrimond et. al., 2015) and total organic carbon of LBH.

Uncertainty Analysis of Lower Barmer Hill Unconventional Play Storage Model

Data and Methodology used for Storage Model:

The data and the workflow used to generate the storage model is briefly described in the figure-2. The original Hydrogen Index (HI_o) and the original TOC (TOC_o) maps for entire basin were also made using the HI and TOC data from the drilled wells on the structural highs. The source thickness map (H) was also made using the existing well and seismic data ((Dutta, et.al, 2019). The oil retained volume was calculated using the following equations:

Oil expelled= 6.29*H * (Rr/Ro) * S *Ci *TOC_o *10-3 (mmbbls/km2)

Where,

H= Net Thickness of Source Rock
TOC_0 = Original Total Organic Content
Rr = density of source rock;
Ro= density of hydrocarbons;
S= Sorption capacity for oil; base case assumed to be 120 mgHC/g TOC
Ci = The fraction of inert carbon;
*Ci = 1-HI_o*Tr*0.85/1000.*

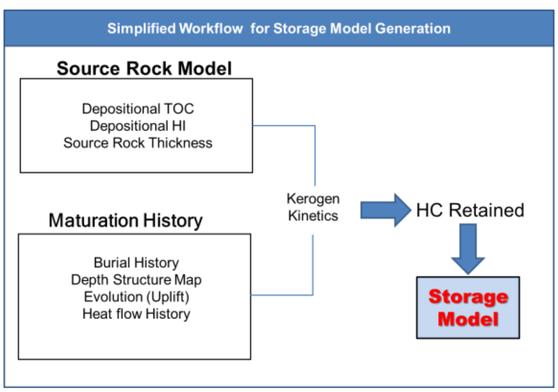

Figure-2: Wrokflow used for Storage Model Generation

Earlier Vs Updated Input Paramters:

The major input elements to the both the versions of storage model (earlier and updated) were source thickness, original TOC and depositional HI maps. The source thickness map (H) was also made using the existing well and seismic data. However, the definition of source rock thickness has been updated based on new understanding. The new source rock thickness incorporated in the current study is more than the earlier considered thickness and it is due to the fact that we have observed possible thickening of synrift shale packages in the deeper part of the basin (Figure-3).

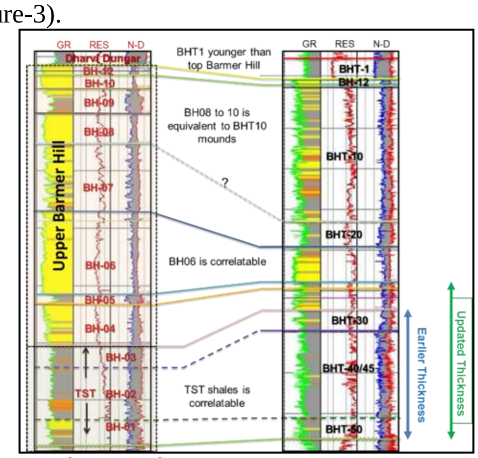

Figure-3 Definition of LBH stratigraphic boundary Earlier Vs Updated

Earlier the source rock thickness was maximum up to 250m, but with the new definition the source rock thickness has increased and goes up to 500m (Figure-4).

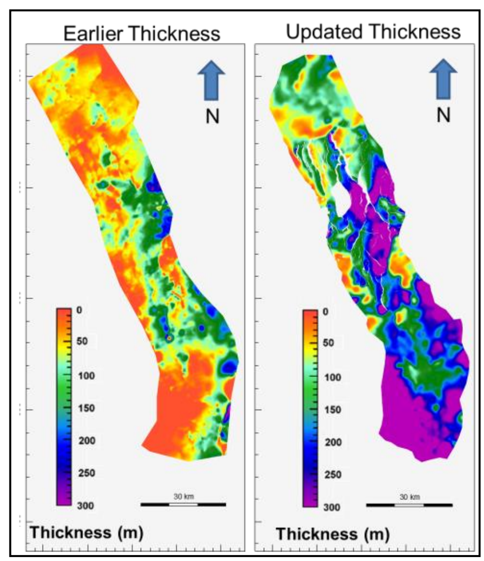

Figure-4: Change in Thickness due to new stratigraphic boundary definition of LBH.

The earlier original TOC and HI maps were prepared based on the measured TOC and HI on core and cutting data which are limited to only few wells. However in this updated work, more number of TOC data points are generated using a modified Passey's

Uncertainty Analysis of Lower Barmer Hill Unconventional Play Storage Model

technique. This technique is adopted, in combination of NMR log, to calculate kerogen volume. This is a variation of Delta-LogR plotting technique (Rt-RhoB overlay) adding Total porosity in the overlay (Figure-5). 60 wells across the basin with NMR data in LBH section is selected. The kerogen volume and TOC are calculated from total NMR porosity and density log using the NMR density approach detailed in Gonalez et. al. (2013). The mineral grain density is assumed to be 2.70 g/cm3 (obtained from core analysis), kerogen density assumed to be 1.15 g/cm3. The log derived TOC curves show good match with measured Leco TOC data (Figure-5) (Dutta, et.al, 2019).

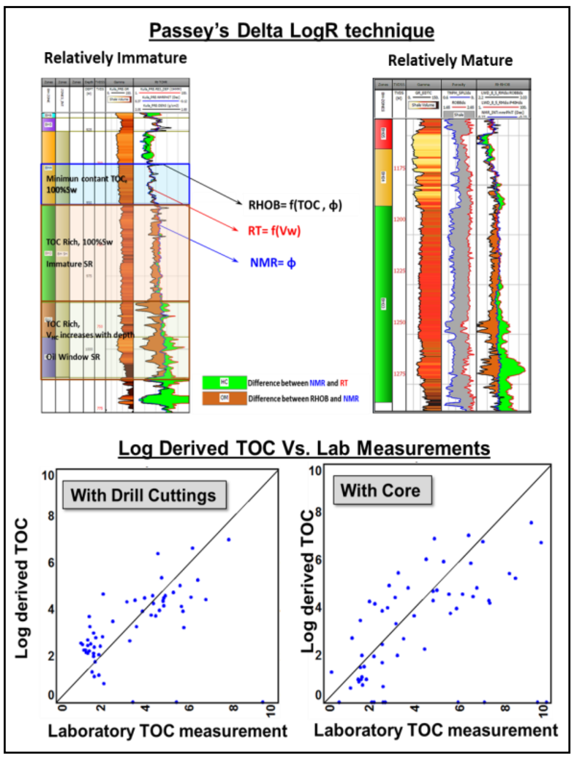

Figure-5: Modified Passey plotting technique to graphically show organic matter content and oil saturation in source rock facies, by including NMR total porosity overlay over the Delta_LogR overlay technique (using Rhob and Rt in this case). The NMR total porosity is plotted in a density-porosity scale assuming a mineral density of 2.65 g/cm3 (in this case) to match background shale. The difference between NMR total porosity and RHOB gives the organic matter content while the separation between NMR total Porosity-RT indicates presence of hydrocarbon within the source rock. Fair match between log derived and Leco TOC shown in the plots.

The original total organic content (TOC_o) for 60 wells are calculated from the log derived TOC data using the following equation.

$$TOC_{(o)} = TOC_{(p)} * (HI_o / HI_p)$$

- *TOC(o) – Depositional TOC*
- *TOC(p) – Present Day log derived TOC*
- *HI(o) – Depositional HI*
- *HI(p) – Present Day HI*

The current updated TOC_o map is generated based on the more data points and the updated gross depositional environment (GDE) of LBH (Figure-6) (Dutta, et.al, 2019).

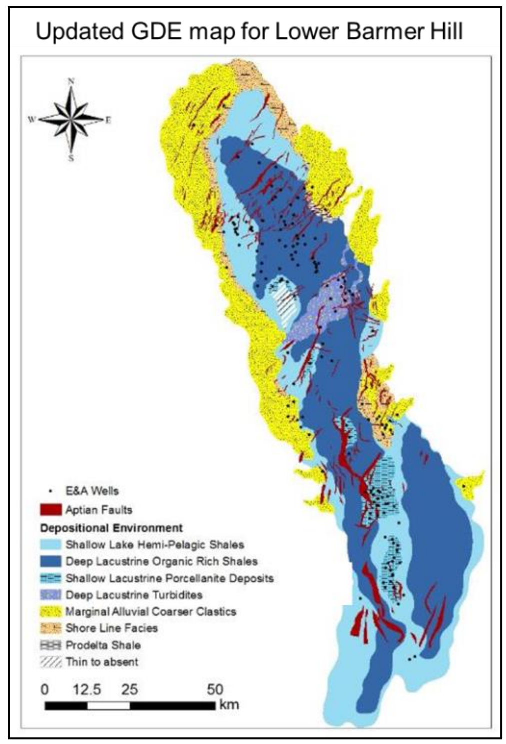

Figure-6: Gross Depositional Environment map of Lower Barmer Hill

The difference between the earlier TOC_o map and the updated TOC_o map can be well observed in the figure-7. The trend of the updated original TOC is driven by the GDE map. The deep lake environment is more suitable for higher organic richness and slowly it decreases towards the shallower marginal areas (Figure-7).

Uncertainty Analysis of Lower Barmer Hill Unconventional Play Storage Model

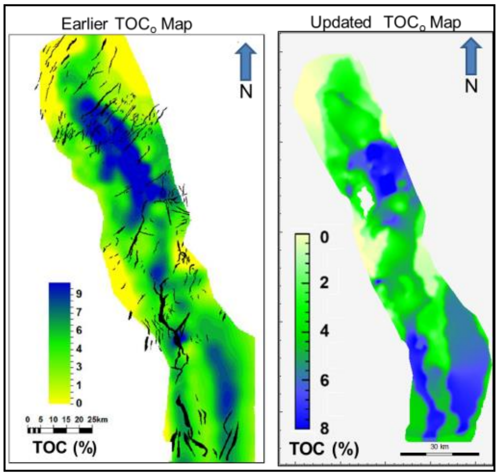

Figure-7: Original TOC map Earlier vs. Updated

The depositional hydrogen index (HI_o) was earlier mapped based on limited lab measurements. But currently, HI_o is calculated from the maceral percentages obtained from the visual kerogene using the following formula (Jarvie et al., 2007).

$$HI_o = \left(\frac{\%\text{ type I}}{100} \times 750\right) + \left(\frac{\%\text{ type II}}{100} \times 450\right) + \left(\frac{\%\text{ type III}}{100} \times 125\right) + \left(\frac{\%\text{ type IV}}{100} \times 50\right)$$

The depositional HI calculated from the maceral percentage shows a good relationship with the present day HI measured through Rock-Eval data (Figure-8).

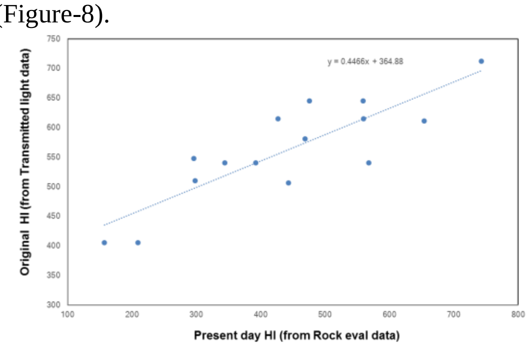

Figure-8: Correlation between Present day HI and depositional HI (derived from maceral)

HI_o calculated from the maceral data were used to generate the depositional HI. Earlier, the depositional HI values were at a lower range based on the lab measured HI data on the highs (Figure-9). But in the updated map, we have considered slightly more HI in the depocenters, thus used the GDE and paleo-bathymetry as a trend in the map generation process.

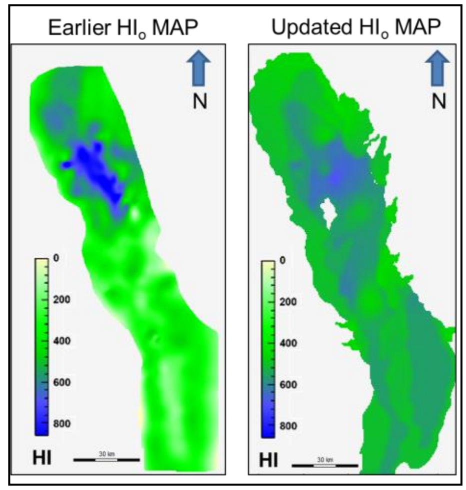

Figure-9: Depositional HI map Earlier vs. Updated

Earlier Vs Updated Storage Model:

Using the above three updated maps (source thickness, original TOC and depositional HI), three storage models are generated.

Storage Model-1: Keeping everything same as that of the earlier model, we changed only the thickness. We observed an increase of 97% of OOIP as compared to the earlier storage model only within the kitchen areas. Even new kitchen areas are coming up in the central part of the basin as the potential areas for shale oil exploration (Figure-10).

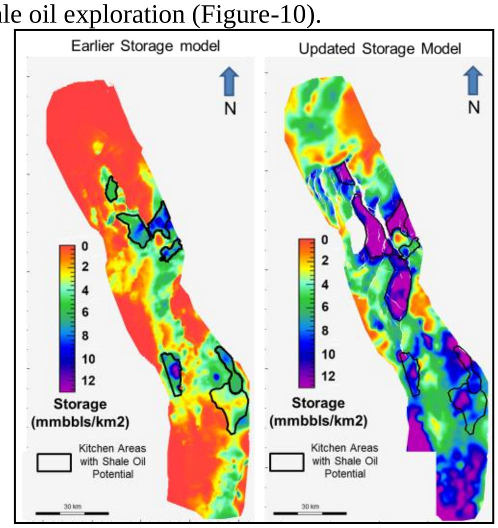

Figure-10: Earlier vs. Updated Storage Model (with updated source rock thickness)

Uncertainty Analysis of Lower Barmer Hill Unconventional Play Storage Model

Storage Model-2: This model is generated using the updated TOC map and all other input parameters were kept same as that of earlier model. No major change in the storage capacity is observed. The storage capacity within the kitchen areas increased by 12% only as compared to earlier model (Figure-11).

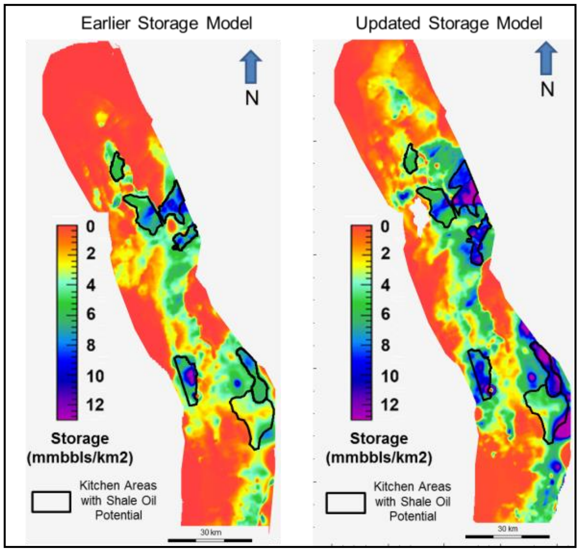

Figure-10: Earlier Vs. Updated Storage Model (with updated TOC_o Map)

Storage Model-3: In this model, all the parameters of earlier storage model was kept intact except the depositional hydrogen index (HI_o). The updated HI_o map discussed above is incorporated in the updated storage model. No major change is observed in the updated storage model. However the storage capacity within the identified kitchen areas decreased by 8%.

Conclusion:

The objective of this study was to carry out a sensitivity study of the earlier storage model to capture the most important input parameter that drives the storage capacity of the LBH. To complete this work, three important maps i.e. source rock thickness, original TOC and depositional HI are updated with alternate understanding. Then, three different storage model are generated by incorporating the three updated maps. Source thickness was found to be the most important input parameter that influences the storage capacity of the LBH whereas TOC and HI has minimal impact.

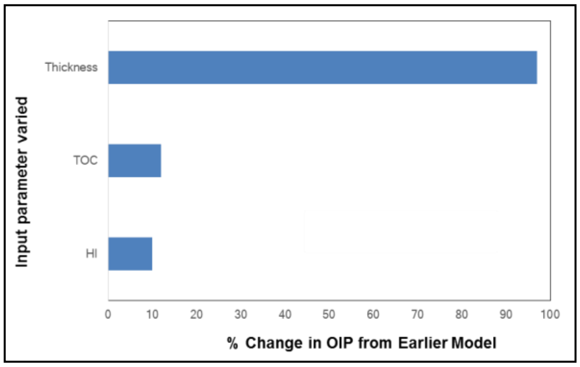

Figure-11: Sensitivity of storage model to the input parameters

This study has not only helped us to capture the most influencing input parameters, but also guided us to be more careful in choosing the source rock thickness (Gross/Net). This study also guided us to acquire more geochemical data in the central and southern part of the basin where there is a chance of getting additional resource. We have very less well data available within the identified kitchen areas so the input maps have some level of uncertainties. However, based on this study and the available seismic data, our further plan is to generate a robust velocity model to reduce the uncertainty in the source rock thickness.

Acknowledgement:

The authors are grateful to Cairn Oil and Gas, Vedanta Ltd and its JV partner ONGC to give the permission to present the work. The authors also acknowledge all the contributions of all past and present members of Rajasthan Exploration department, including Sandipan Dutta, Sabyasachi Dash, Kiran Kumar Talagapu, Debjani Bakshi, Adesh Pandey, Kasturi Das, Neelanjana Bid, Priyabrata Chatterjee, Rahul Singh, Hriday Jyoti Bora, Chandramohan Rautela, Ajoy Krishna Bora, Shubhodip Konar, Subhrashis Adhikari, Anindya Bandyopadhyay, Bineet Mund, V.R. Sunder, and V. Kothari in collective understanding of the basin. We would also acknowledge Dr. Geir Hansen and Per Erling Johanssen from Applied Petroleum for their help in collecting laboratory geochemical data, Dr. Paul Green from Geotrack International for his help in AFTA measurement and thermal history reconstruction, Dr. Zhiyong He for consulting on

Uncertainty Analysis of Lower Barmer Hill Unconventional Play Storage Model

shale oil & gas workflows with Trinity™ software and Dr. Paul Farrimond for his help with geochemical interpretation.

References:

Dutta, Sandipan, Kuila, U., Naidu, B.S, Yadav, R.K., Dolson, J., Mandal, A., Dasgupta, S., Mishra P., Mohapatra, P., 2019. Integrated Approach to Assess Storage and Productivity Potential of a Frontier Unconventional Shale Oil Play in a Rift Basin, Lower Barmer Hill Formation, Barmer Basin, India. URTEC-2019-537-MS, SPE/AAPG/SEG Unconventional Resources Technology Conference, 22-24 July, Denver, Colorado, USA. https://doi.org/10.15530/urtec-2019-537

Dolson, J., Burley, S.D., Sunder, V.R., Kothari, V., Naidu, B., Whiteley, N.P., Farrimond, P., Taylor, A., Direen, N. and Ananthakrishnan, B., 2015. The discovery of the Barmer Basin, Rajasthan, India, and its petroleum geology. AAPG Bulletin, 99(3): 433-465.

Farrimond, P., Naidu, B.S., Burley, S.D., Dolson, J., Whiteley, N. and Kothari, V., 2015. Geochemical characterization of oils and their source rocks in the Barmer Basin, Rajasthan, India. Petroleum Geosciences, 21(4): 301-321. https://doi.org/10.1144/petgeo2014-075

Gonzalez, J., Lewis, R., Hemingway, J., Grau, J., Rylander, E. and Pirie, I., 2013. Determination of formation organic carbon content using a new neutron-induced gamma ray spectroscopy service that directly measures carbon. Presented at the Unconventional Resources Technology Conference, Denver, Colorado, 12-14 August, 2013. https://doi.org/10.1190/urtec2013-112.

Naidu, B. S., Burley, S. D., Dolson, J., Farrimond, P., Sunder, V. R., Kothari, V., and Mohapatra, P., 2017. Hydrocarbon Generation and Migration Modeling in the Barmer Basin of Western Rajasthan, India: Lessons for Exploration in Rift Basins with Late Stage Inversion, Uplift and Tilting, in Mahdi A. AbuAli, Isabelle Moretti, and Hege M. Nordgard Bolas, eds., Petroleum Systems Analysis: AAPG Memoir, 114: 61–94.

Passey, Q.R., Creaney, S., Kulla, J.B., Moretti, F.J. and Stroud, J.D., 1990. A practical model for organic richness from porosity and resistivity logs. AAPG bulletin, 74(12): 1777-1794.