Innovative Petrophysical Evaluation Workflow Enhances Production: A Case Study from Barmer Basin, NW India*

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Abstract

The Vijaya and Vandana (V&V) fields, located in the central part of Barmer basin, were discovered in 2005 by Cairn. The oil bearing Barmer Hill Formation consists of two types of reservoir packages– sandstones/heteroliths deposited as lacustrine hyperpicnites and porcellanites with alternations of diatomite and mudstone layers. Sandstone lithofacies is the main reservoir rock, but with permeability vastly impaired by cementation. The porosity of these sandstones ranges 10-20% and show permeability variation of 0.01-200mD. Numerous pay zones of 5-10 meters are dispersed over gross rock thickness of about 500m. Conventional testing of individual pay zones in initial wells produced oil at sub-commercial rates.

The challenge was to characterize the rock in terms of permeability variation and identification of zones requiring stimulation treatment. Core analysis data sets including sedimentological descriptions, RCA, thin sections, XRD and MICP were integrated to understand the factors controlling the reservoir properties. Rock classification posed challenges in terms of wide variation in permeability within a narrow porosity range due to dominant post depositional alterations, pore-filling cements such as siderite, dolomite and dispersed clays. Microscopic imaging along with MICP pore size distribution suggested a strong influence of degree of cementation and subsequent dissolution on the present day pore geometry in sands, which influences the measured permeability.

The petrophysical workflow consisted of integration of conventional core data with NMR log data to provide pore size classification. Based on pore throat size using thin section photomicrographs and mercury porosimetry data, three distinct sand sub classes have been identified viz., tight sandstone with permeability ~0.01-0.1mD, moderately tight sandstone (~0.1-10mD) and sandstone with cement dissolution (~10-200mD). Pore size distribution through binning of NMR T2 spectra was found to be comparable with the MICP observations. A rock quality index derived using NMR bins was used to identify these sandstone sub-classes in wells. This workflow has resulted in a fit-for-purpose rock type assessment and quantifiable porosity to permeability transform for each rock class. Further, log derived absolute permeability is tied to effective permeability obtained from pressure transient analysis like PBU, mini-DST and DFIT. Identification of good permeable zones and
accurate prediction of K*H (permeability*net pay) against reservoirs pay sands in V&V fields is found to be critical in estimating full production potential of wells.

The result of this study was instrumental in identification of zones for hydraulic stimulation. Available test data helped in understanding the relationship between K*H connected against the flow rates achieved in existing wells. Two separate trends could be clearly established for the stimulated (hydro fractured) and unstimulated wells, which further helped in making realistic forecast in new wells. Hydraulic fracturing carried out against selected intervals based on this petrophysical workflow in a recent well resulted in 10 fold increase of fluid rate by connecting multiple pay zones. The workflow customized for V&V has resulted into an evolving story for production enhancement, and will be further tested in the upcoming early development through existing and new wells through total connected K*H.

References Cited


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Synopsis

The oil bearing Barmer Hill Formation in the V&V field comprises of sandstone lithofacies as the main reservoir rock. However, permeability of these sandstones is vastly impaired by cementation. Rock classification posed challenges in terms of wide variation in permeability (0.01-2000 mD) within a narrow porosity range (10-20%) due to dominant post depositional alterations, pore-filling cements such as siderite, dolomite and dispersed clays. Conventional testing of several pay zones (average thickness ~5m) in initial wells produced oil at sub-commercial rates. Hence, accurate prediction of KH (permeability/net pay) against reservoir sands is found to be critical in: (1) estimating full production potential of the wells and (2) optimizing intervals for hydraulic stimulation. Effective integration of core and NMR data in V&V has resulted in a fit-for-purpose rock type assessment and quantifiable porosity to permeability transforms. Comparison of log based predictions with the well test observations provided a better confidence on estimated permeability (K). Further, Net pay (H) definitions are also calibrated to core and formation tester data. Hydraulic fracturing carried out based on the results of this workflow in a recent well resulted in 10 fold increase in well deliverability by connecting multiple pay zones. The workflow customized for V&V has resulted into an evolving story for production enhancement, and will be further tested in the early development through existing and new wells through total connected KH*H.

Study Area

Typical Sandstone mineralogy in V&V

Typical clay mineralogy in V&V sandstones

Lithology: Sandstone, Porcellanite & Claystone

Reservoir Porosity: 10-20%

Marine Permeability: 2-100 mD

Reservoir Pressure: 3600-3900 psig

Reservoir Temperature: 95-100°C

Reservoir Fluid: Oil and Water

Oil quality: API 37-40 Viscosity 1cP

Workflow adopted for permeability prediction

Electron factors work flow

Factors based porosity-permeability transforms with core data

Pore size based rock typing with NMR log

Results and Discussion

Innovative Petrophysical Evaluation resulted in additional production enhancement opportunities, thus increased well deliverability.

- Rigorous data integration helps in assessing flow capacity(KH) in the V&V fields, that reasonably matches with the performance of well test
- Predictable relationship observed between KH vs. rate in tested wells (both stimulated & non stimulated)
- Results proved to be pivotal in Hydrofrac placement and assessing the commerciality of wells
- The workflow will be further utilized in the early development phase in testing all KH based pay intervals in unlocking field potential

**Methodology**

**Constraining cut-offs for defining ‘Net’**

Reservoir cut-off used in V&V field: PHT>10% & VSHALE<=55%

Good fluorescence is observed above porosity >10% in core proving the presence of oil.

MDT mobilities suggest that 10% is the minimum porosity beyond which fluids moved due to high drawdowns during protests.

Sand thickness counted on core was used to calibrate the volume of shale cut-offs.

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<th>Differential Permeability</th>
<th>Permeability Predicted from logs tie well with the same obtained from PTA analysis of well tests</th>
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<th>Relationship observed in the V&amp;V fields between total connected KH and flow rates achieved for stimulated and unstimulated wells</th>
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<th>Problem Statement</th>
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- Sensitivity of Production Forecast

- Prediction error in KH can impact most in forecasting the production rates.
- Hence KH prediction is the most important criteria in tight reservoirs to get the rates correctly
- Un-optimized placement of frac and inefficient treatment leads to sub commercial wells

**Challenges**

- 80% of the STOIIP in the V&V fields lie in sandstones having permeability <1mD
- Dominant control of diagenesis over reservoir properties. Wide variation of permeability within a narrow range of porosity
- Thin pay zones (~4-5m thick) are dispersed over gross thickness of ~400m
- Hydraulic stimulation required to connect multiple pay zones
- Connecting total KH available in the wells is key for achieving commercial flow rates

**Background**

- KH is the key for achieving commercial flow rates
- Connecting total KH available in the wells is key for achieving commercial flow rates
- KH= 21 mD x 5 ft
- KH= 36 mD x 20 ft

**Results**

- Initial production forecasts were unsatisfactory
- Modified method resulted in improved forecasts
- Production enhancement techniques such as hydraulic fracturing, cementing, etc. were implemented
- Significant improvement in production was observed

**Conclusions**

- The workflow adopted for permeability prediction is a key component in achieving commercial flow rates
- Further optimization and calibration of the workflow is required to enhance well deliverability

**Synopsis**

- The oil bearing Barmer Hill Formation in the V&V field comprises of sandstone lithofacies as the main reservoir rock.
- Permeability of these sandstones is vastly impaired by cementation.
- Conventional testing of several pay zones (average thickness ~5m) in initial wells produced oil at sub-commercial rates.
- Accurate prediction of KH (permeability/net pay) against reservoir sands is found to be critical in:
  1. Estimating full production potential of the wells and
  2. Optimizing intervals for hydraulic stimulation.
- Effective integration of core and NMR data in V&V has resulted in a fit-for-purpose rock type assessment and quantifiable porosity to permeability transforms.
- Comparison of log based predictions with the well test observations provided better confidence on estimated permeability (K).
- Net pay (H) definitions are also calibrated to core and formation tester data.
- Hydraulic fracturing carried out based on the results of this workflow in a recent well resulted in a 10 fold increase in well deliverability by connecting multiple pay zones.
- The workflow customized for V&V has resulted into an evolving story for production enhancement, and will be further tested in the early development through existing and new wells through total connected KH*H.