# Evaluation Of Miocene Reservoir in the "Horse" Field

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***Abstract- The Miocene reservoir of the "Horse" Field comprises sands, silts and muds, attributed to deposition from short-headed submarine fan. The reservoir ranges in thickness from 30.5 m to 122.0 m. It is characterised by variable net-to-gross ratio, porosity and permeability. The Oil-Water-Contact (OWC) is found at -4353.8 mTVDSS as obtained from well logs. The reservoir has a base Original Oil in Place (OOIP) of 643 million Barrels. The aim of this study is to assess connectivity in the Miocene reservoir interval.***

***Based on the analysis of meso-scale architectural elements, three facies' sequences were delineated: HM1, HM2, and HM3. Among these sequences, HM2 sand has the best reservoir quality. Available data suggest that this sand forms the highest pay within the Miocene reservoir. The crest of the main anticlinal fold, which forms the major structural trapping system, is moderately faulted. If these faults are sealing, they may effectively compartmentalize the reservoir resulting in poor reservoir connectivity.***

***Indexed Terms- facies, net-to-gross, connectivity, compartmentalization.***

## I. INTRODUCTION

The "Horse" Field is an offshore field that is located in the Gulf of Mexico at water depth of 1646 m. The field was discovered in 1999 and was brought on stream in 2002. There are 8 oil production wells and 2 water injection wells. The production capacity of the wells stands at 75,000 barrels of oil per day and gas production capacity of 72 million standard cubic feet per day. Water production stands at 25,000 barrels of water per day.

This study is aimed at evaluating the Miocene reservoir through (1) mapping the reservoir on 3-D seismic data, (2) preparing structure and isopach maps for the reservoir, (3) identifying meso-scale reservoir architectural elements and their reservoir quality, and (4) assessing key uncertainties and related risks that impact oil resource, production rate and profile.

## II. GEOLOGICAL SETTING

The Miocene reservoir in the "Horse" Field is a turbidite system that deposited within a submarine fan complex. It consists of sandstone of channel-fill facies and laminated sandstone interbeds that are classified as levee deposits. Porosity in the field ranges from 20-35% and permeability ranges between 100 md to 6,000 md. Three subdivisions are made in the Miocene reservoir based on reservoir quality. These subdivisions are: HM1, HM2, and HM3. Among these subdivisions, HM2 is the most extensive and productive.

## III. METHODS

The definition of the top and base of the Miocene reservoir was done using integrated approach based on well logs, core, and 3-D seismic data. Meso-scale architectural elements were identified from core recovered from well H-01. In the Miocene reservoir, three meso-scale architectural elements were identified and subsequently form the basis for classification of the reservoir into HM1, HM2, and HM3 sequences. Root Mean Square (RMS) amplitude (Figure 1) was generated over the reservoir and used to map high net-pay HM2 channel-fill sand body.

## IV. RESULTS

### *A. Meso-scale Architectural Elements*

The three architectural elements observed from core are: (1) sheets (2) channel (3) overbank mounds.

The sheet geometry typified by HM1 consists of vertically stacked layered sand sheets. There are fluid escape structures indicating rapid burial of sediment. The sand body is characterised by moderate net-to-gross ratio with thin mud laminae that tend to reduce vertical connectivity in the Miocene reservoir. Horizontal connectivity of sand body is good resulting in good horizontal permeability. It is an heterolithic section. The vertically stacked channel-fill sequence that typifies HM2 consists of upward fining sequence. This sequence is marked by high net-to-gross and good vertical connectivity, particularly within individual channel fill. Internally, laminations, ripples and loading structures are common in this sequence. Presence of thin shale lens indicates possibility of baffles within the interval of HM2. The mounded structure of channel-levee system characterises HM3. The sequence comprises upward fining laminated sands with mudstone interbeds.

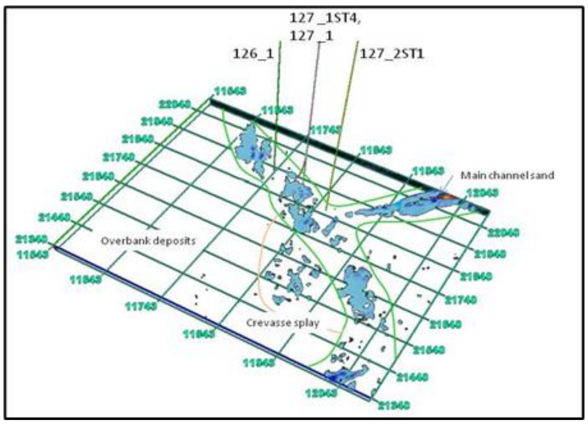


Figure 1: RMS amplitude of the M sand reservoir with outlines of key channel geometry.

*B. Field Structure and Trapping System*

The "Horse" Field consists of an anticlinal fold plunging to the southwest. A major normal fault east-trending down-to-the-north forms the trap in the northern boundary (Figure 2). The eastern and updip trap consists of south-trending shale-filled by-passed channels.

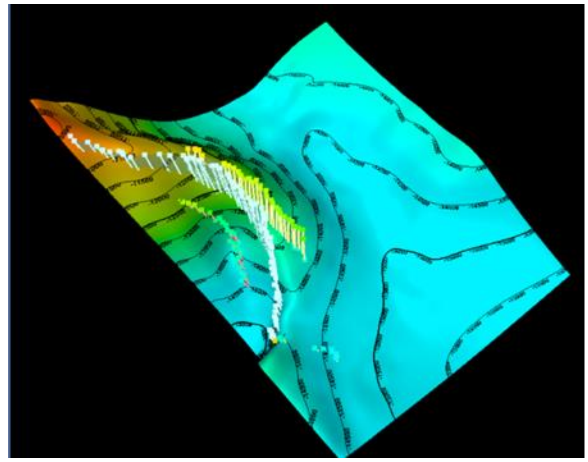

Figure 2: Structure map with major faults in the Miocene reservoir.

*C. Stratigraphy and Net Pay Definition*

HM1 sequence corresponds to vertically stacked sheet-like sand bodies that have high net-to-gross (about 57%). In HM1 interval, lateral continuity of sand bodies results in good lateral connectivity. Occurrence of interbedded mudstone reduces vertical connectivity among the sheet sand bodies. The HM2 sequence displays the highest net-to-gross ratio (approximately 80%) among the three Miocene reservoir sub-units. The homogeneous sand that dominates the interval is the cleanest and consists of oil stain. The sand is characterized by good porosity and permeability. The presence of normal faults within the reservoir interval tends to reduce communication resulting in lower flow rates. HM3 sequence is marked by low net-to-gross (about 37%). Within the interval, mud packages are thicker and they constitute potential barriers to vertical flow. In general, the Miocene reservoir is between 30.5 m to 122.0 m thick (Figure 3).

*D. Fault Geometry and Reservoir Connectivity*

One major fault was delineated from seismic section. The major fault trends E-W direction along the crest of the anticline (Figure 4). The behaviour of the fault together with the associated minor faults remains uncertain. If these faults are sealing, they may effectively compartmentalize the reservoir (Figure 5), which will result in poor reservoir connectivity.

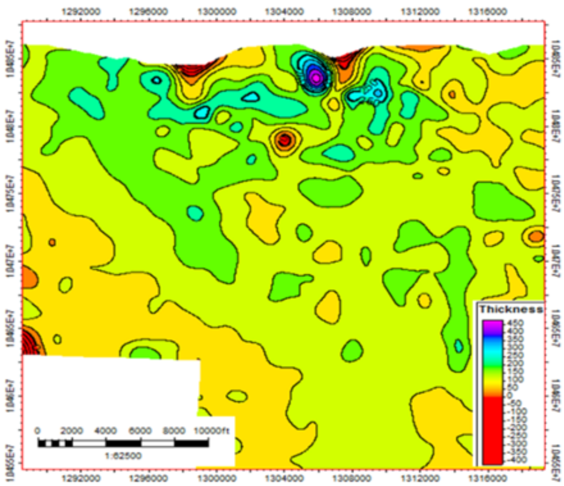

Figure 3: Isochore map of Miocene reservoir.

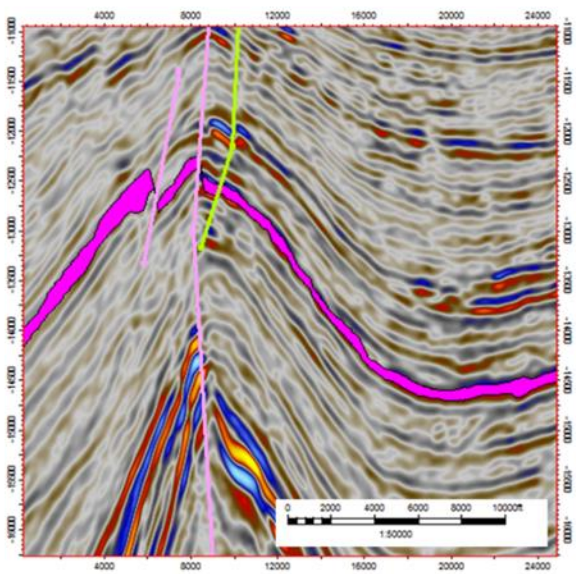

Figure 4: North-South intersection showing the Miocene reservoir interval (in purple) superimposed on seismic data, major faults are shown.

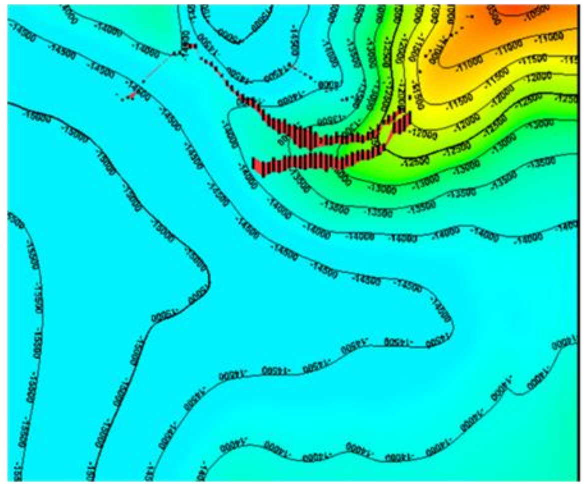

Figure 5: Schematic Miocene reservoir map with geometry of major faults.

DISCUSSION

*A. Volumetric Analysis*

Three scenarios were defined to represent Original Oil In Place (OIIP) in the Miocene interval (Table 1). The base case is calculated to be 643 million barrels, whereas the downside and upside cases are calculated to be 402 million barrels and 981 million barrels, respectively.

Table 1: Scenario-based OIIP for Miocene reservoir.

| Properties | Downside case | Base case | Upside case |
|---|---|---|---|
| Net-to-gross | 0.30 | 0.40 | 0.50 |
| Porosity | 0.27 | 0.27 | 0.27 |
| Oil saturation | 0.50 | 0.55 | 0.60 |
| OOIP (million barrels) | 402 | 643 | 981 |

*B. Key Uncertainties and Associated Risk with Miocene Reservoir*

*1) Structural Mapping of Miocene Reservoir*

Uncertainty in structural mapping from seismic section will affect Bulk Rock Volume, height of hydrocarbon column, and net-to-gross ratio, particularly in HM1 and HM2 sequences. Fluid saturation interpreted from well logs is also a source of uncertainty in calculating resource. Over-estimation of OIIP, which will lead to promises of unrealistic reserve (Fox and Bowman, 2010) and an oversize development plan are risks that are associated with uncertainty in structural mapping.

*2) Trapping Framework*

The sealing potential of the major faults serving as reservoir boundary cannot be determined from the available data. In addition to this uncertainty, the OWC, which forms the base of the hydrocarbon column was defined using limited well data. Thus, these uncertainties are associated with the risk of underestimating the resource. The sealing potential of faults could also change during production causing the reservoir to be compartmentalized. With compartmentalization, more wells will be required to drain the reserve.

*3) Size of Resource*

The size of resource was estimated using 3-D seismic data integrated with well data. This value may change as production continues and more data are acquired. Inappropriate development plan, which may result in low production rate due to inadequate facility is the major risk that is associated with the uncertainty in resource.

*4) Size and Strength of Aquifer*

The size and strength of aquifer cannot be determined using available 3-D seismic or well data. The effectiveness of natural drive from aquifer support is a big uncertainty that is associated with the risk of low recovery and failure to deliver promised production rates.

*C. Impact of Risks on Resource, Production Rate and Profile*

*1) Resource*

The crest of the anticlinal fold that forms the main structural trap in the Miocene reservoir is faulted. The dynamic behaviour of these normal faults cannot be accurately predicted until production commences. If these faults permit the migration of oil to the overlying sands, then, the OIIP in the Miocene reservoir will reduce.

*2) Production Rate*

Among the factors that will affect production rate are pore scale displacement efficiency, which will be controlled by ability of depletion strategy to displace the oil, rock/fluid type and recovery process. The drainage efficiency will be controlled by the compartments and development phasing. The reservoir geometry and heterogeneity, well type and spacing and the movement of mobile oil to wells will control the sweep efficiency. Cut-offs will be controlled by the physical and commercial constraints affecting end of field life, reservoir energy, facilities and license issues. In addition to these factors, global price of oil is a key uncertainty that affects production rate. Production of more oil when the global price of oil is very high will attract additional cost to production e.g., drilling of new wells, upgrading facilities to handle increased production rate, etc.

*3) Profile*

Compartmentalization implies the presence of extensive permeability barriers in the Miocene reservoir. The impact of compartmentalization will lead to more wells to effectively drain the reservoir. Other impacts on production profile are financial exposure, reduced communication between injection well and production well, reduced connectivity between pay zones, and reduced reserves.

## CONCLUSION

Based on findings in this study, best reservoir quality is found to occur in the HM2 sequence. Porosity and permeability in the Miocene reservoir are strongly controlled by facies type. Interbeds of mudstone in addition to potential compartmentalization due to a series of normal faults will pose a significant threat to fluid flow in the Miocene reservoir during production. Additional data are needed to reduce the uncertainties that relate to trapping framework, structural mapping, size of resource and size and strength of aquifer. Flow simulation studies may be carried out to assess the effectiveness of aquifer drive to displace oil to production wells.

## ACKNOWLEDGMENT

The author thanks members of DAP 3 Project Team of the University of Manchester, UK for access to data that was used to carry out this study.

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