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Evolution Of Mangala Reservoir Model Through The E&P Lifecycle: Learnings And Way Forward

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ABSTRACT

Reservoir models evolve through the field development life cycle both in terms of objectives and complexity. Models built during the appraisal phase are fairly simple, created to capture the uncertainty in STOIIP and EUR. During the field development planning, aim of reservoir modeling is to identify the right development strategy and place the wells optimally. In the late field life, models are built to identify remaining hydrocarbon areas and planning for enhanced oil recovery methods. This paper describes the journey of Mangala Field from its discovery to the current day with Enhanced Oil recovery focusing on the journey and evolution of the static Reservoir Model along the way with progressive complexities. A synoptic view on future appearance is also captured using the analogous mature fields.

Mangala Field located in the Northern Barmer Basin was discovered in Jan 2004. The structure is a tilted fault block bounded by the main bounding fault on the West and North West with beds dipping to the East at about 9 deg. The producing reservoirs are fluvial sandstones of Fatehgarh and Gaghar-Hakkra Formation. The discovery well and the six appraisal wells established a common Oil-water contact in the field. Initial seismic interpretations were carried out on PostSTM data and depth conversion was based on a polynomial function using the initial exploration and appraisal wells. Subsequent development wells indicated presence of lateral velocity changes which were incorporated by constantly updating the Velocity model. The top depth uncertainty was reduced from >20 m during the appraisal phase to <10 m in the currently drilled infill wells. One of the biggest uncertainties impacting GRV was lateral position of the main boundary fault mainly due to poor seismic data quality and fault shadow effect. During the appraisal and subsequent development phases, wells were drilled to tag the main boundary fault, reducing the uncertainty from a > 125 m in the appraisal phase to < 50m at present. The focus of the structural model now has shifted to minor intra- field faults influencing hydrocarbon sweep and water influx in producers.

The property models built during the appraisal phase were fairly simple and largely stochastic with objects based facies models and sequential gaussian simulations for porosity based on seven wells. Challenge in the appraisal stage was lack of data resulting in large uncertainties. Over time the property models have become more constrained with advanced geophysical inversion inputs together with petrophysical interpretation from >300 wells. In addition, the models are also restrained by production history, tracer breakthrough, cased hole saturation logs and routine surveillance data. Constraining and matching models with all the data from different sources bring a new set of challenges. With more than 300 wells object based facies models eventually fail, sequential indicator models and recently multi-point statistics have been used to build facies realizations. Overall facies proportions and NTG trends are well understood but establishing reservoir connectivity and sweep between injector and producer pairs is still challenging in some areas.

With extensive data gathering in the appraisal phase, use of high resolution 3D seismic data and subsequent drilling of > 300 wells, the uncertainty in hydrocarbon in-place volumes have reduced from ~25% in the appraisal phase to~ 5% at present. As we enter the EOR phase in Mangala, focus has shifted to detailed sector models to understand impact of polymer and ASP injection and model incremental oil recoveries. These models are based on high resolution correlations from comprehensive core description, detailed core analysis and petrographic studies from > 400m core taken from closely spaced wells.