Assessing Key Uncertainties in The Development Plan Of "Success" Field

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Abstract- Data derived from several appraisal wells has shown the "Success" field to be a viable development project. The field is highly faulted with a southern sealing boundary fault.

Based on uncertainties that relate to trap mechanism, production rate, net-to-gross distribution, permeability heterogeneity, and size and efficiency of aquifer to provide natural drive, a three-phase production profile is designed to target four hydrocarbon-bearing sand bodies. Proposed development plan involves a depletion strategy comprising 8 water injection wells and 19 oil production wells. Prior to start-up production, flow should be simulated to monitor reservoir performance under primary and secondary recovery mechanisms. The impact of water and subsequently gas production should also be assessed to inform injection strategy for maximum oil recovery.

Indexed Terms- net-to-gross, permeability heterogeneity, trap, simulation.

I. INTRODUCTION

"Success" Field is located in the continental shelf at water depths of 300-500 m. The field was discovered in 1993 by well SE 1 that penetrated an oil-water contact (OWC) at 2062 mTVDSS. Estimated Original Oil In Place (OOIP) is approximately 1400 million barrels. Reservoir geometry was mapped on 3-D seismic data. In mid-1994, five appraisal wells were drilled. Following the drilling of these wells, a horizontal well, HS-01, was drilled to carry out Extended Well Test (EWT). This well encountered a reservoir interval with gross thickness of c. 1700 m. The test was aimed at assessing reservoir performance, particularly the connectivity and productivity of the sandstone reservoirs, denoted as S1-S4. The EWT achieved a stable flow rate of 18,000 barrel of oil per day (BOPD) and demonstrated good productivity and reservoir connectivity. This study is aimed at proposing a field development plan that will optimise oil recovery early on at start-up production.

II. GEOLOGICAL SETTING

The field is located in the continental shelf, approximately 200 km away from the mainland. It is located close to a prominent subsea ridgeline, which probably generated sediment gravity flows that resulted in deposition of turbidite sand and associated debrite that form the reservoir facies in the field. The reservoir sandstones are classified as Tertiary. The reservoir architecture is attributed to channel activity that produced high net-to-gross channel-fill facies. The area is highly faulted, being within an extensional tectonic setting.

III. METHOD

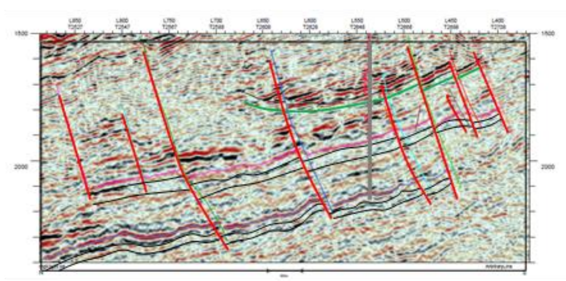
The development plan for "Success" Field is based on integrated subsurface description of the reservoir using available data, trap configuration, reservoir characterisation and fluid description. Net pay thickness maps were produced directly from 3-D seismic data and provided information for reservoir description. The architecture of the reservoirs was defined using seismic attribute mapping technique and detailed seismic facies mapping integrated with sedimentological analysis of cores and wireline logs. Repeat Formation Test (RFT) provided formation pressure data that were plotted against depth for fluid characterisation. The risks and uncertainties that are associated with the evaluation are reduced based on consideration for base case, upside and downside case scenarios. This measure is to mitigate the impact of uncertainties on resource, rate, profile and recovery mechanisms.

IV. RESULTS

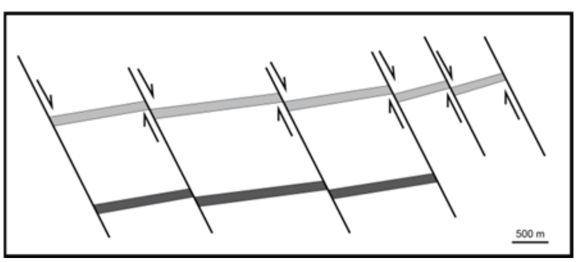
A. Trap

In the Success Field, structural trapping style comprises a series of normal planar fault blocks trending East to West (Figure 1). The faults are high angle (typically 40-60°), dipping to the south and with varying offset distances. Vertically, faulting is extensive with major faults dissecting several key strata and some of the faults displaying extensive lateral continuity. There is no visible major deformation of strata around the fault planes, suggesting faulting is post depositional.

The sealing component of key faults is unclear allowing for further investigation. However, the southern-most fault is believed to be sealing forming the southern boundary of the field.



(a)



(b)

Figure 1: Structural framework for "Success" Field (a) structural interpretation of 3-D seismic data (b) structural model showing trap configuration.

B. Reservoir Definition

Four distinct reservoirs are defined in the "Success" Field. These reservoirs are: S1, S2, S3, and S4. Based on observations from net pay maps and well logs, S1 and S2 reservoirs are composed of channel-fill facies. S3 reservoir, by contrast, consists of non-amalgamated turbidite sand, mud, intraclast, and matrix-supported conglomerate, and S4 is interpreted to have been deposited by debris flow. Examination of core recovered reveals amalgamated sand body that is homogenous, fine-grained and well-sorted in the S1 and S2 reservoirs. Due to absence of mud drapes, permeability is very good both horizontally and vertically throughout these reservoirs. In S3 reservoir, grains are poorly sorted resulting in low vertical permeability with mud-rich layers probably acting as flow baffles in the reservoir. S4 reservoir consisting of debrite facies grades gradationally from laminated sand into homogenous, amalgamated sands of S1 and S2. The reservoir quality in S4 reservoir is poor due to poorly sorted grains within fine sand matrix and low vertical permeability.

C. Reservoir Geometry and Connectivity

As observed from Gamma Ray log, S1 is characterized by sheet-like geometry with thin layers of non-reservoir lithology separating S1 reservoir sheet-like sands. Within the reservoir facies, horizontal permeability is inferred to be good but vertical permeability is thought to be reduced by the presence of non-reservoir layers. S2 reservoir is horizontally and vertically homogenous hence permeability is good in both directions due to absence of non-reservoir facies. Horizontal and vertical flow in S1 and S2 reservoirs may be impeded by mudstone, which constitutes permeability baffles and barriers within the reservoir intervals.

Connectivity between these reservoirs vertically is limited due to the presence of thick mudstone units separating them. Sealing capacity of the faults may affect lateral migration predominantly in the N-S direction, which is a function of shale smear, cataclastics and/or diagenesis. However, the fault sealing potential may change its behaviour with production due to dynamic nature of faults during production (Jolley et al., 2010).

D. Fluids

The "Success" Field is a virgin oil field with saturated fluids full to spill, and reservoir pressures close to bubble point. Formation pressure data indicates there is no gas cap (Figure 2). Fluid densities range from 0.70-0.85 g/cc indicating the presence of oil in the reservoir. Fresh water (1.0-1.02 g/cc) is also found in the reservoir. The Oil-Water contact is found at 2062 mTVDSS.

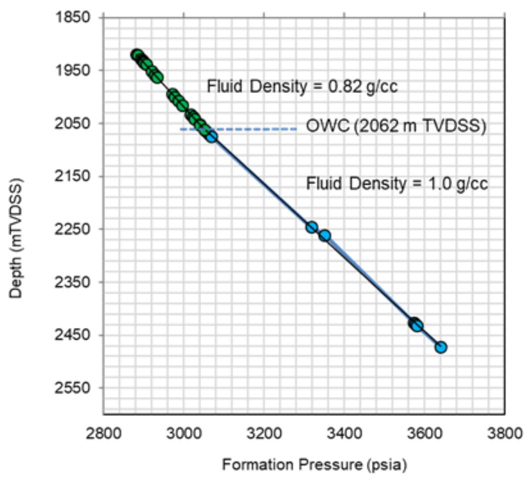


Figure 2: A plot of Formation Pressure versus Depth.

V. DISCUSSION

A. Risk and Uncertainty Characterisation

The uncertainties in the field are trap, rate of recovery, porosity, permeability, net to gross, position of fluid contacts, and size of aquifer.

1) Trap

The main trap uncertainty is whether the faults act as conduits or barriers to flow. The presence of deformation features may influence the changes in cross- or along-fault communication induced by reactivation events. When faults act as flow barriers, compartmentalization of the reservoir will result (Fox and Bowman, 2010; Gainski et al., 2010; Jolley et al., 2010). As a result, reservoir characteristics may differ from compartment to compartment. Thus, detailed analysis of every fault and seal in a compartment will help to unravel this variability for effective field development and optimum hydrocarbon recovery.

The impact of trap uncertainty could result in lower production rate and low recovery. Where the faults are not sealing and the reservoir has a simple structural framework (i.e., not compartmentalized), the production rate and recovery factor will increase.

2) Production Rate

The extended well test that targeted S3 turbidite deposit indicated a good production rate of 18,000 BOPD, which could be higher in more homogenous reservoirs such as S1 and S2. This uncertainty will impact long-term forecast of cumulative production and project value.

3) Permeability and Volume of Shale

Permeability varies within the reservoir intervals. S1 and S2 reservoirs have good permeability, whereas S3 and S4 reservoirs have low permeability based on observations from core photographs. Lateral and vertical variations of permeability in the reservoirs will result in large permeability contrast, which will cause flow segregation and impact recovery factor. Low permeability will require development plan to consider fracturing to improve pore communication, thus increasing production cost and reducing profit.

In addition, volume of shale in the reservoirs is an uncertainty arising from estimation that is based on Gamma Ray log. Combined neutron-density logs will help to reduce this uncertainty and allow a more accurate net-to-gross value for estimating reserves. The net-to-gross value obtained from net pay maps could also be a source of uncertainty as a result of considerations made during seismic interpretation. Chief among these considerations is depth conversion. Uncertainty in net-to-gross value will impact Original-Oil-In-Place (OIIP) estimate and project value.

4) Size and Efficiency of Aquifer

The nature and size of aquifer represent a huge uncertainty that can impact oil recovery in "Success" Field. The size of the aquifer will determine if the reservoirs will produce under natural aquifer drive, otherwise, secondary recovery mechanism may be considered to provide pressure support and improve recovery at start-up production. This additional pressure support will attract additional production cost and affect project value.

B. Reservoir Management Plan

1) Resource

The OIIP is estimated to be 1400 million barrels. Based on this value, three scenarios or cases were generated to obtain recoverable oil (Table 1). The base case represents a most reasonable estimate with a 30% recovery factor and 420 million barrels of oil reserves.

	Upside Case	Base Case	Downside case
Recovery factor	40%	30%	20%
Reserves (MMBO)	560	420	280

2) Production Profile

The field life is planned to be 15 years covering production start-up, plateau, and decline stages (Figure 3). These stages have variable oil production rate, peaking at 150,000 BOPD. This peak production is to be sustained for at least 3 years by water injection. The field is to be managed by providing additional pressure support that will reduce the decline rate and extend the field life for 10 years post-plateau production.

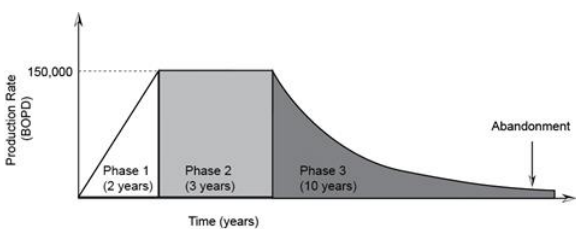


Figure 3. Production profile in time for "Success" Field.

3) Recovery Mechanisms

Based on the uncertainty that concerns the nature and size of aquifer, the reservoir management plan will incorporate waterflooding strategy to provide pressure support to the reservoir and optimize recovery from the start-up. The gas that will be produced when the bubble point is reached may also be injected to provide additional sweep for maximum oil recovery.

C. Reservoir Development and Production Plan

The following factors are considered in the development plan for "Success" Field: (1) a flexible drilling strategy, (2) an efficient water injection strategy to replace produced oil and maintain reservoir pressures, and (3) a gas disposal strategy. Therefore, the proposed depletion strategy will include 8 water injection wells and 19 oil production wells.

CONCLUSION

From this study, key risks and uncertainties that impact the choice of development strategy include trap type and characteristics, production rate and profile, permeability heterogeneity, and size and nature of aquifer. The proposed development plan involves 8 water injection wells and 19 oil production wells.

The impact of trap uncertainty could result in lower production rate and lower recovery factor. The complexity and sealing potential of the fault are also uncertain. The production rate in the homogeneous reservoirs of S1 and S2 is uncertain thereby impacting long-term production forecast. The distribution of volume of shale within the reservoir can also impact net-to-gross and permeability distribution.

Therefore, it is important to acquire more data that will provide information and help to reduce these key uncertainties. Flow should be simulated to monitor reservoir performance under primary and secondary recovery mechanisms prior to production start-up. The impact of water and subsequently gas production should also be assessed to inform injection strategy for maximum oil recovery.

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