Proven Approach to Optimizing Recovery in a Heavy Oil Shallow Marine Reservoir, Usari Field, Offshore Niger Delta

Olatunbosun A. T, Onyido I. M, Kumapayi O. Y., Onyido C. P, Idih R., Anene C., Akinpelu J. K., Thomas-Ideh Osivwi and Adagbasa E. Goodluck
Mobil Producing Nigeria Unlimited

ABSTRACT

Usari field is located approximately 25km offshore Nigeria, with a field STOIIP of over 1.5GBO. The field is comprised of stacked shallow marine sands with good reservoir properties. The field is set-up by two extensional faults with five reservoir groups. Usari Alpha is the most developed reservoir in terms of well density and has undergone several development phases since 1999. The oil in this reservoir is heavy (18oAPI, 5.6cp viscosity), not typical in the Niger Delta. Also, the reservoir is relatively shallow, with unconsolidated sands that have high porosity and permeability. These rock and fluid characteristics pose challenges to depletion strategies despite a strong aquifer drive system. With over 20 years of production data and multiple development phases, this paper discusses the successful reservoir management strategies deployed and learnings over time. It also focuses on the next development phase that can potentially increase current oil recovery of 40% to >50%. Some key insights from the depletion strategies include the positive impact of long lateral completions, dense well spacing to improve areal sweep and large tubing size to improve liquid offtake. Similarly, high liquid rate, special screen completions and Inflow Control Device (ICD) helped drawdown distribution along the entire completion interval while maintaining sand free production. The next development phase focuses on value generation and adoption of cost-effective technology solutions like coil tubing for potential recompletion in existing wells and multi-lateral well design that target attic oil above existing perforations. Achieving this leverages the re-processed Anisotropic PreStack Depth Migrated Seismic to refine subsurface characterization as well as integrating recent well data from areas affected by shallow gas anomaly to re-define reservoir gross rock volume and in-place resource. .

Key Words: Optimization, Reservoir management strategies, Well spacing, Control device, Coil Tubing, Migration and Anistropic

INTRODUCTION

Development of high viscous oil is relatively uncommon in the Niger Delta due to the sizeable number of conventional oil development opportunities still available and the belief that secondary recovery methods are required to achieve comparable recovery levels (Ajayi *et al,* 2008). In Usari, the Alpha reservoir (figure 2) is the most developed in terms of well density and has undergone several development phases since 1999. The reservoir oil is heavy (18^{o}API, 5.6cp viscosity) with adverse mobility, not typical in Niger Delta. In addition to this, the oil column is relatively thin (~70ft), the reservoir is shallow, unconsolidated sands with high porosity and permeability. These pose challenges to depletion strategies despite a strong aquifer drive system.

With over 20 years of production data, multiple development phases and learnings, this paper discusses the successful reservoir management strategies. It focuses on the next development phase that can potentially increase current oil recovery of 40% to >50% (~25-40 MBO incremental EUR). Some key insights from the depletion strategies include the positive impact of long lateral completions, dense well spacing to improve areal sweep and large tubing size to improve liquid offtake. Similarly, high liquid rate, special screen completions and Inflow Control Device (ICD) helped drawdown distribution along entire completion interval while maintaining sand free production.

Field Overview

Usari Field is located is shallow offshore Niger-Delta in water depths of ~65ft (figure 1), in an NNPC-MPN Joint Venture acreage operated by Mobil Producing Nigeria Unlimited. The Field was discovered in 1964, streamed in 1997 with development wells that targeted the five (5) main reservoir groups (figure 2). To date, 52 producers have been drilled to deplete the oil reserves in the Field.

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Three major stratigraphic units make up the Tertiary of the Niger Delta: the shale-prone Oligocene to Miocene Akata Formation, the interbedded sands and shales of the Miocene - Pliocene Agbada Formation, and the sand-prone Pleistocene - Recent Benin Formation (Kreisa *et al* 1998). All three formations are present in Usari Field.

The producing reservoirs in the Field are within the "bedded" Biafra Member of the Agbada Formation, which are primarily fluvial and shallow marine (i.e., Shoreface and Deltaic EODs) deposits in this area (Buckley, *et al.,* 2002).

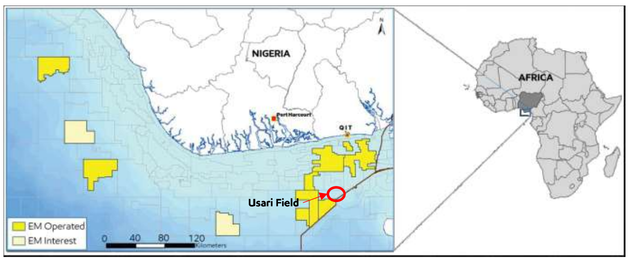

Figure 1: Regional map of Africa showing Mobil Producing JV Acreage with Usari Asset in Highlight.

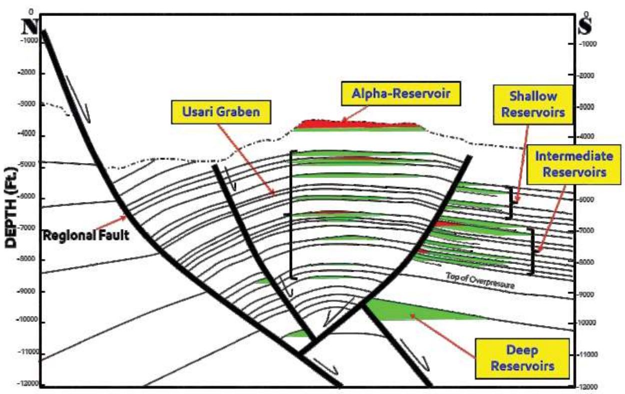

Figure 2: Geologic cross section showing Usari Field Trap Configuration and Reservoir Groups.

Usari Alpha Reservoir Geology

The Alpha reservoir is associated with a regional tectonic event in the Messinian (Me2) – a massive regional collapse and erosional unconformity. Alpha erosion is localized to either the footwall of large normal faults or related to a late-stage erosional canyon that cuts into existing deposits (figure 3). The Alpha reservoir within the Agbada Formation is subdivided into two (2) hydrocarbon-bearing lithostratigraphic members: Bedded Biafra (otherwise referred to as Competent), and Disturbed Biafra (Rubble Beds). The Alpha reservoir in Usari field occur wholly within the Bedded Biafra member, dominated by deltaic and shoreface sands (Olatunbosun *et al.,* 2021). The Qua Iboe shale serves as the regional seal with erosional subcrops forming the hydrocarbon trap (figure 3).

The main depositional environment is interpreted to be distributary channel with some upper shoreface sand deposits. The shales are discontinuous and act as baffles in production time scale. Petrophysical properties of the Alpha reservoir are good, with average porosity of 32%, permeability of 3-10 Darcies, over 90% net to gross and an average water saturation of 11% (Ajayi *et al,* 2008)

The Usari Alpha structure is a four-way anticlinal closure with crestal stress-relieving faults (figure 4). Control on hydrocarbon contact is believed to be dependent on a combination of the structural closure and fault juxtaposition leaks.

The Alpha reservoir in Usari area has good data control with a high-quality 3D seismic data that constrains the gross rock volume, calibrated by over sixty (60) wells. Hydrocarbon presence within the Alpha is often characterized by elevated amplitude response that can be easily distinguished. An exception to this is in the poorly imaged zone directly below the shallow gas anomaly, that attenuates amplitudes below it (figure 5).

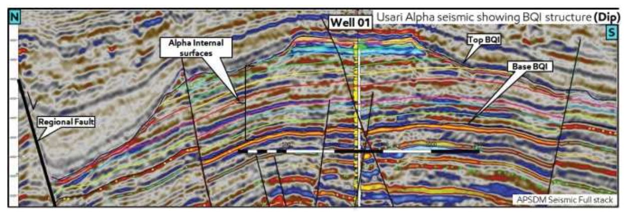

Figure 3: Seismic cross section highlighting Usari Alpha structure.

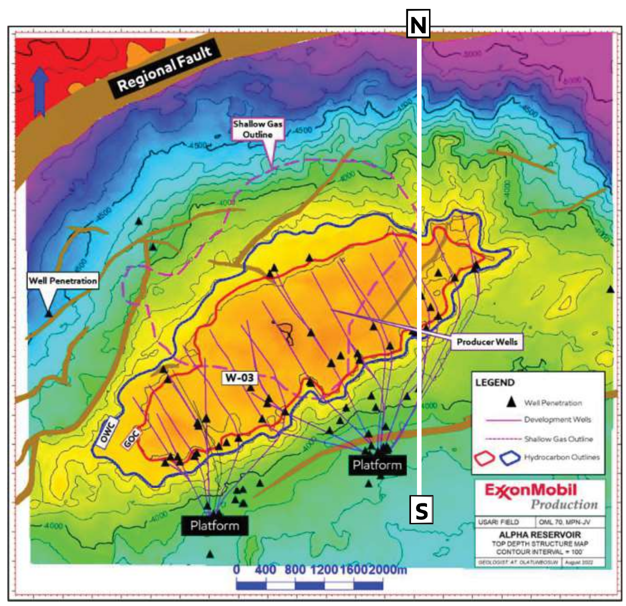

Figure 4: Usari Alpha Top Depth Structure Map with hydrocarbon outline overlay.

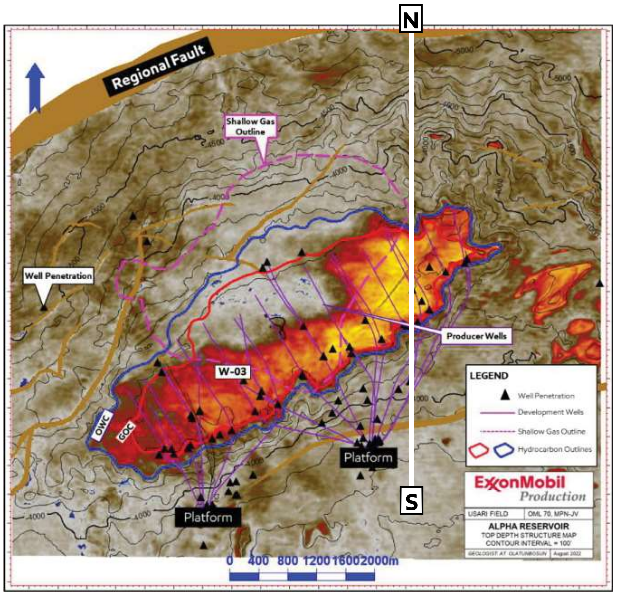

Figure 5: Usari Alpha Top Depth Structure Map overlain by minimum amplitude extraction.

Historical Alpha Development

The first Alpha development efforts were in 1967 with the completion of the W-03 appraisal well (figure 5), as an oil producer, following the installation of the first wellhead platform over W-03. The well ceased production due to low wellhead pressure in less than one year and was subsequently plugged and abandoned (P&A). The failure of this first Usari Alpha development attempt happened as a result of lack of adequate understanding of the fluid flow dynamics, in view of the heavy oil characteristics.

Phase 1 Development: Full reservoir development of the Alpha commenced in 1999. This development phase included four horizontal wells 1-4, spaced 800m apart (figure 6), with ~1500ft lateral completions length and 2-7/8' tubing using ResLink completions without ICDs. The small tubing size restricted total liquid production to about 3kbd. These wells were also gas lifted to help get the heavy oil to the surface through the production tubing.

Phase 2 Development: In 2005, the reservoir was further developed with seven (7) additional wells. - three (3) of which were replacement for the watered-out phase 1 wells. The remaining four (4) were areal infill wells to improve areal sweep efficiency. Unlike in phase 1, the phase 2 wells had long lateral completions length (~4000ft) with a larger 4-1/2" tubings using ResLink completions without ICDs. They were also gas lifted from the onset. The large tubing size installed in the wells improved liquid offtake, with wells streamed at initial rates of 5-10kbd.

Phase 3 Development: Due to the low oil recovery, high produced water, and poor areal sweep as a result of the nature of the oil and water coning, a major field study was commissioned to further improve on reservoir understanding including optimal reservoir management method. The study leveraged field performance from analog fields in Australia and proposed further infill drilling to aid reservoir performance. Production Logging Tests (PLT) on the phase 2 wells indicated no production contribution beyond 2500ft of completions, highlighting the inefficiency of the ResLink completions without ICDs. This study led to an additional nine (9) infill drilling campaign to maximize hydrocarbon recovery. Unique changes in the development strategy here were the tighter well spacing of 400m, and introduction of a different type of completion - ResFlow with ICDs. These wells had an average of 4000ft lateral completions length. Pre-water break through PLTs indicated full lateral length contribution with the ICDs. The post study drilling saw

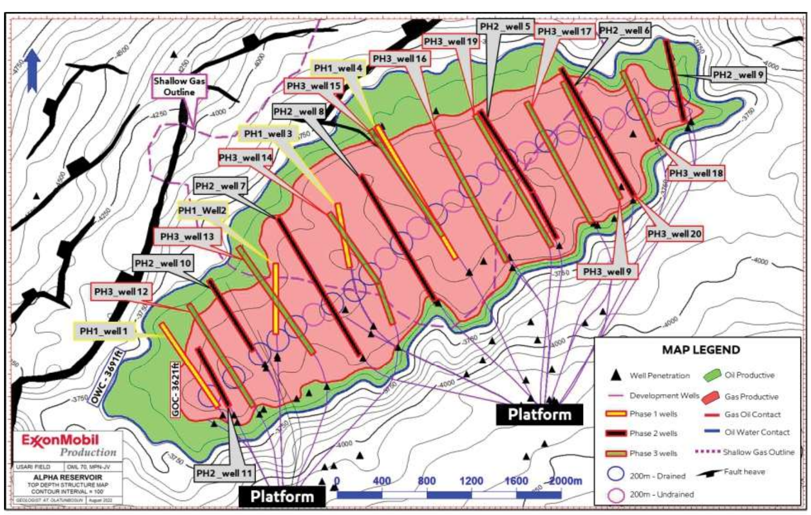

Figure 6: Usari Alpha Top Depth Structure Map with Reservoir Fluid Contacts and Development wells.

production rise from 5kbd to about ~50kbd within 9 months (Olopade et al, 2005).

Impact of Improved Seismic Data:
One of the factors that impacted the field development over time was improvements in the seismic data. The initial data were relatively short offset streamer that were post-stack time migrated. These datasets were reprocessed multiple times until the acquisition of the JV multicomponent OBC (Ocean Bottom Cable) data. The OBC seismic was initially time migrated (Pre-Stack Time Migration – PSTM). The data was last reprocessed using depth imaging technology APSDM.

These technology advances – longer cables, wider offsets, improved signal processing techniques and better imaging algorithms (Olatunbosun et al). This happened in parallel with other subsurface information acquired through drilling and dynamic data.

METHODOLOGY

Usari Alpha depletion strategy has evolved through time as efforts are made to optimize recovery and production rates. This involved integration of geoscience and engineering data to unravel the subsurface complexities. The aim was to establish a development strategy that enhances production and optimizes hydrocarbon recovery, while maintaining an optimal reservoir management scheme.

The development strategy evolution was informed by reservoir studies, applying learnings from analog fields in Australia with similar fluid type and geology. Simulation also helped in defining multiple scenarios that had impact on the development strategy. These include the optimal required number of wells, expected ultimate recovery, well spacing, etc. The simulation model helped to understand the reservoir behavior, predict production performance, and helped perform sensitivities. This model incorporated data from reservoir characterization, well tests and production history to simulate different development strategies, helping to identify the most effective one.

Detailed seismic interpretation helped define the lateral extent and structure of the Alpha in Usari area. In-depth production scale sequence stratigraphy which provides the stratigraphic framework for analyzing reservoir facies as well as facies distribution away from well control was also carried out. Each sequence was divided into systems tracts that were analyzed with core and log facies information to produce the environment-of-deposition (EOD) maps for the different subzones. Interpretation of connected flow units and intervening baffles and barriers within and between the systems tracts were further refined with the integration of pressure data, production data, and fluid contact analysis. Reservoir properties were estimated using available conventional logs and core data. The available core was described, and reservoir facies were interpreted using JV-wide core-calibrated matrix to interpret reservoir facies

To further hydrocarbon recovery, and address rising high water cut, after decades of production, a 4th phase development drilling has been proposed. This phase leverages significant learnings from the current well performance and the development strategy evolution. To this end, the reservoir characterization was refined leveraging the re-processed Anisotropic PreStack Depth Migrated Seismic (APSDM), while also integrating recent well data from areas affected by the shallow gas anomaly to re-define reservoir gross rock volume and in-place resource.

Several learnings were obtained from dynamic fluid behavior and near wellbore performance monitoring using production logging tools (PLTs). This dataset which was instrumental in refining the type of completions used for the last development phase, have also been revisited and integrated with understanding from additional production data.

Results and Discussion
Key insights from the successful depletion strategies for Usari Alpha includes the positive impact of long lateral completions, dense well spacing to improve areal sweep and large tubing size to improve liquid offtake. Similarly, high oil rate - high water production strategy, special screen completions and Inflow Control Device (ICD) helped drawdown distribution along entire completion interval while maintaining sand free production. Given the analog field data and simulation predictions from the 2005 studies, the depletion strategy that involved producing the wells to very high-water cuts (95%) has aided oil recovery with improved ultimate recovery predictions.

Well Spacing
For this type of heavy fluid with a thin oil column of 70ft, simulation and analog data demonstrates the inefficiency of the conventional 800m well spacing. Drainage area is confined to a conical area under the horizontal completions. Australia analogs showed sharp water cones with ~200m base width (Fabian, 1999), similar to observations in Usari Alpha (figure 7). Post production wells drilled after 2-3 years of production within 200m lateral space of the older wells logged fluid contacts that were close to the original hydrocarbon contacts, suggesting a limited lateral drainage of the existing producer wells. The simulation model was used to model well spacing of 267m, 400m, and 805m (figure 8). A tight well spacing of 400m was recommended (phase 3 development) and has proved effective over the years (figure 7), with actual production closely matching 2005 forecast.

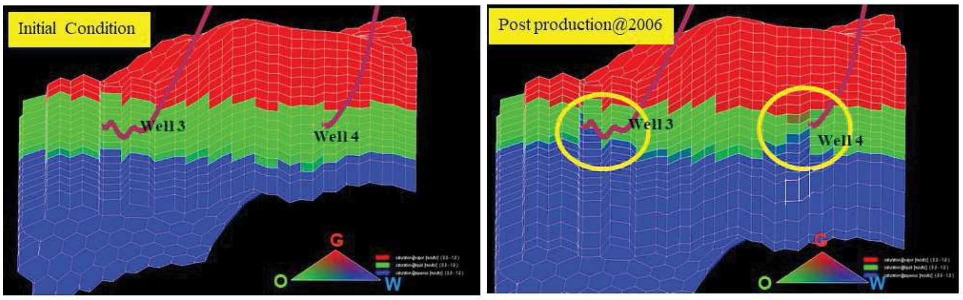

Figure 7: Producer wells highlighting conical drainage based on reservoir simulation.

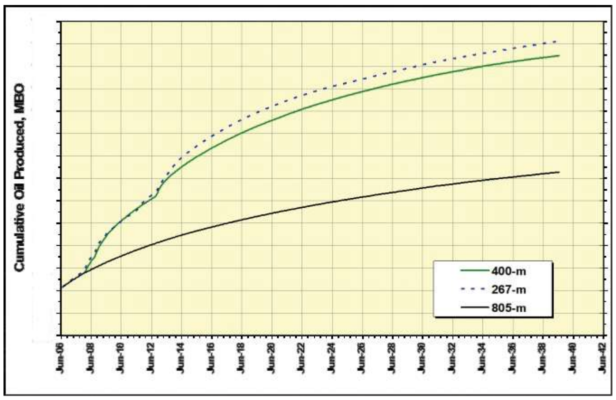

Figure 8: Cumulative oil production forecast sensitivity based on different modeled well spacing.

Wellbore Design and Completion Strategy

Well design and completion type played a vital role in Usari Alpha reservoir management. Long horizontal wells were required to reach as much areas of the reservoir as possible due to adverse mobility of heavy oil that limits drainage areas. Hence, the completions design required long lateral horizontal wells with Resflow completions with ICDs for efficient reserves capture. In addition to the long lateral wells, large tubing size completions was also critical to improve on liquid offtake. Sensitivities on the optimal completion length was done using the simulation model (figure 9).

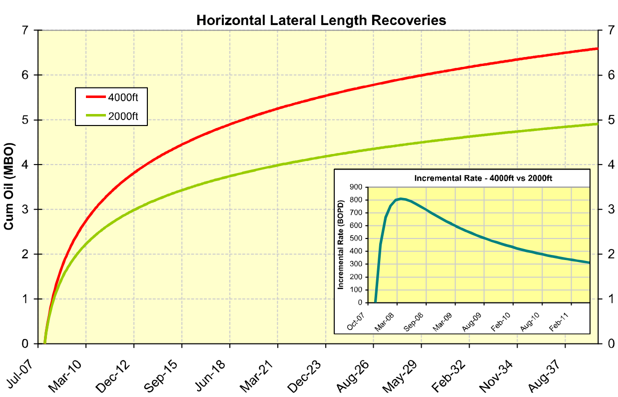

Figure 9: Model sensitivity on completions length and its relationship to produced oil.

Phase 1 development wells had ~1500ft lateral completions length and 2-7/8' tubing with ResLink completions without ICDs. The small tubing size restricted total liquid production to about 3kbd. Phase 2 development wells had ~4000ft lateral completions without ICDs. Production logging test (PLT) on the phase 2 wells indicated no production contribution beyond 2500ft of completions, highlighting the inefficiency of the ResLink completions without ICDs (Figure 10a). The special screen completions and Inflow Control Device (ICD) helped drawdown distribution along entire completion interval with full contribution from the entire 4000ft of lateral completions (Figure 10b). Pre-water break through PLTs indicated full lateral length contribution with the ICDs. Post water break-through PLT also confirmed drawdown distribution along entire 4000ft of lateral completions.

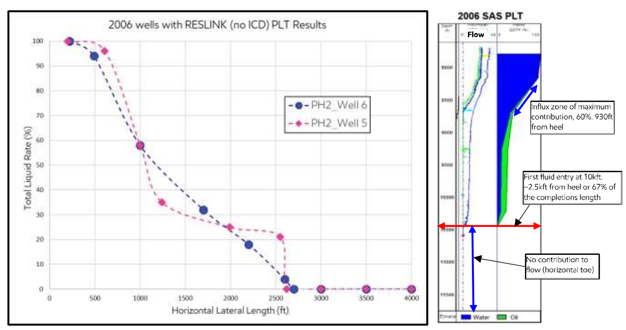

Figure 10a: Post-production PLT in ResLink (no ICD) completions highlighting drainage inefficiency

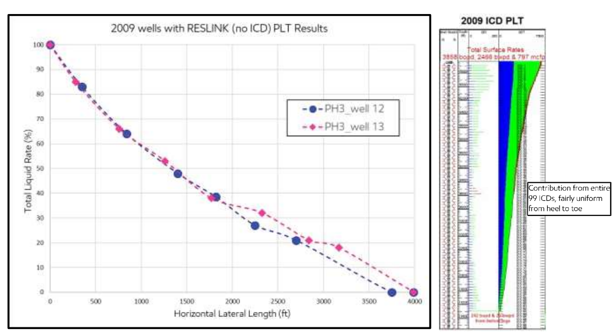

Figure 10b: Post-production PLT in ResFlow ICD well highlighting even distribution of oil flow across the ICDs.

Sand Control Management Strategy

Usari Alpha reservoir is characterized as shallow unconsolidated sands with high porosity and permeability. The unconsolidated nature of the sand poses a unique challenge of sand production, if not mitigated against. Out of the eleven (11) wells drilled during development phases 1 & 2, with no ICD completions, four (4) were shut-in due to significant sand production. PLT logs indicated an uneven flow distribution across the lateral length with significantly higher production and water-cuts around the heel (Figure 10a). The high withdrawal rates / drawdown around the heel is suspected to have caused screen failure resulting in sand production.

Post 2008 wells (Phase 3) completed with Resflow completion and ICDs had a much better statistics, as only one (1) out of nine (9) drilled wells produced sand. This marked a clear improvement compared to the previous development wells. PLT data indicated full lateral length contribution with even drawdown distribution across the lateral length (Figure 10b). The use of this specialized screen helped to control sand production and ensure long-term well integrity.

The successful sand control management strategy can be summarized below

- Complete wells with sand control equipment (ResFlow screens)
- Complete long lateral horizontal wells with ICDs to distribute drawdown
- Install hydrocyclone to conduct sand checks as part of routine well test
- Establish sand free rate via step rate test
- Install Permanent Down Hole Gauges (PDHG) to monitor drawdown

Impact on Production Performance

Phase 1 wells were streamed at ~3kbd with average of 3 MBO barrels of oil production. This is mainly due to the limited lateral length contributing to overall production from the reservoir and small tubing size that limited liquid rate. Most production were less than 5 years before the

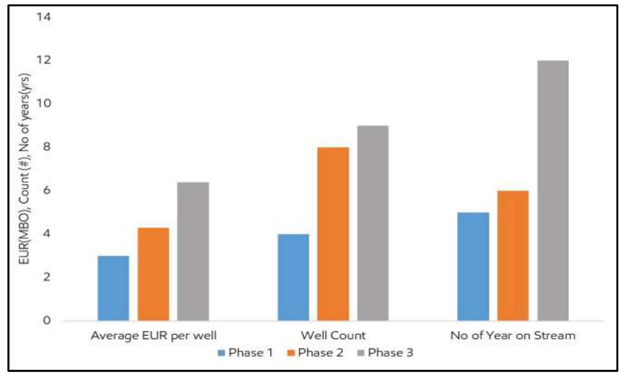

Figure 11: Production Performance Summary for the 3 development phases.

wells quit at high BSW. Average EUR per wells drilled in phase 2 rose by 30% compared to phase one wells. However, the wells were not online for longer period due to some completion failure causing sand production alongside high BSW. Phase 3 wells drilled had longer stream time due to excellent reservoir management and monitoring strategy driven by ICDs in completion design and PDHGs to monitor performance. EUR per well for the phase 3 wells were 100% more than phase one and 60% more than phase 2 development wells (Figure 11).

Proposed Phase 4 Development

All twenty (20) well completions in this reservoir were landed approximately mid oil column. Partly due to the inability to confirm the aquifer strength in the early stages of development. These wells have fairly constant GOR with increasing high water-cut indicative of water drive reservoir with strong aquifer support. Shut in Bottom Hole Pressures (SBHPs) also confirms strong aquifer support. Most of these high water-cut wells are shut in due to the facility's water handling capacity. This presents another opportunity for a 4th phase development, that primarily targets the attic oil above the existing completions. The attic oil has been estimated to be ~25-40ft thick, depending on the area of the reservoir being penetrated (figure 12). The proposed phase 4 development is estimated to increase current oil recovery of 40% to >50%. The infill wells will be landed few feet from the gas oil contact to target the attic oil. In addition, the wells will also be placed

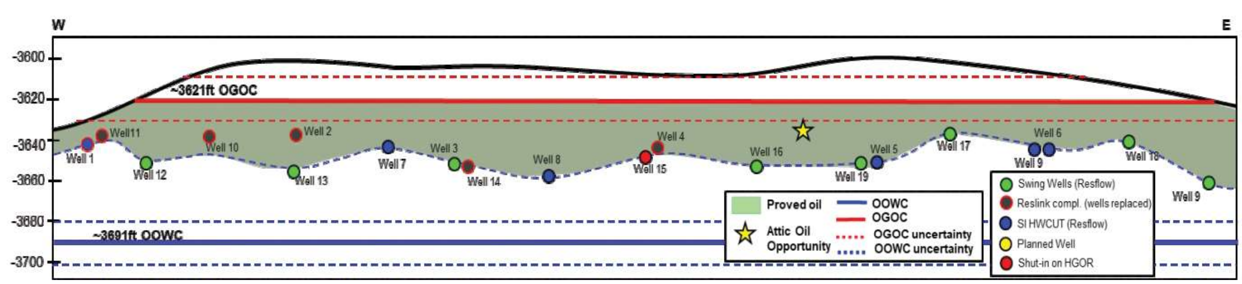

Figure 12: Schematic cross-section highlighting attic oil potential in Usari Alpha.

in-between shut-in wells to improve on the areal sweep efficiency.

This development phase also focuses on value generation and adoption of cost-effective technology solutions like coil tubing for potential recompletion in existing wells and multi-lateral wells that target attic oil above existing perforations. Achieving this involved leveraging the re-processed Anisotropic PreStack Depth Migrated Seismic to refine subsurface characterization as well as integrating recent well data from areas affected by shallow gas anomaly. This resulted in a better definition of the reservoir gross rock volume and in-place resource.

CONCLUSION

The combination of the unique characteristics of the Usari Alpha reservoir presented challenges that needed innovative solutions to address. Some of these features include a shallow reservoir, heavy/ high viscous oil, thin oil column and unconsolidated sands, with high porosity and permeability (Fabian, 1999). A phased development was adopted to enable the evaluation of these attributes, their impact on different depletion strategies, and implementing learnings for continuous improvement.

Continuous monitoring and surveillance of the reservoir was crucial for effective management. This included regular testing, pressure monitoring, and production performance analysis. Surveillance helped in quickly identifying production issues, optimizing recovery techniques, and implementing timely adjustments to enhance reservoir performance.

With over two decades of production data, multiple development phases and learnings, this paper discussed the successful reservoir management strategies that were adopted. Key insights from the depletion strategies include the positive impact of long lateral completions, dense well spacing to improve areal sweep and large tubing size to improve liquid offtake. Similarly, high oil rate - high water production strategy, special screen completions and Inflow Control Device (ICD) helped drawdown distribution along entire completion interval while maintaining sand free production.

The next development phase that can potentially increase current oil recovery of 40% to >50% will focus on value generation and adoption of cost-effective technology solutions like coil tubing for potential recompletion in existing wells and multi-lateral wells that target attic oil above existing perforations.

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