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Optimal Infill Drilling Using Simulation and Cross-Functional Integration-Ubit Field Example

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Abstract

The Ubit Field, located southeast of the Niger Delta, is a Nigerian National Petroleum Corporation (NNPC)/Mobil Producing Nigeria (MPN) Joint Venture (JV) asset that has been on production for more than 40 years (September 1970). Ubit has approximately 2.4GBO OOIP, with production peaking at ~137,000 BOPD in 1997, and is currently at ~85,000 BOPD. With much of the reserves yet to be produced, it is important that an optimized field development plan be implemented to maximize recovery. Guided by reservoir simulation models, a revised Ubit Field re-development plan was approved in December 2009. Infill development has proceeded as designed, and the first infill drilling program is underway.

Integration of results from reprocessed seismic, geologic interpretation, core, log and reservoir simulation studies, coupled with state of the art technology in well completions, were critical in developing an optimized depletion plan. Reservoir simulation results consistently indicate higher reserves capture with increased well density from infill drilling that targets unswept locations around and down-dip of abandoned completions. Results from the integrated studies suggest varying the optimum well spacing requirements for the different sections of the reservoir. The recovery factor in the lower quality reservoir section (Disturbed Biafra) could be vastly improved by increasing well density.

The multidisciplinary study for field development indicates that approximately 100 additional wells should be drilled to tap unswept resource in the field. This aggressive approach will maximize ultimate recovery, but requires closer well spacing than minimum regulatory specification . The technical basis for this strategy, primarily reservoir simulation models anchored in measured hard-data, is the core focus of this paper.

Geologic Overview

The Ubit Field, located in Oil Mining Lease (OML) 67, is an east–west trending anticline bounded by two regional faults (Faults 18 and 19; Figure 1). The axis of the anticline is divided into east and west highs by a flexure (saddle), and several east–west oriented internal faults act as flow baffles. The 4-way trap for Ubit is defined by dip closures and the base Qua Iboe (BQI) unconformity.

The main producing interval in the field is the I-UU1 reservoir within the Biafra Member of the Agbada Formation. This reservoir consists of sediments originally deposited in a progradational deltaic environment, and is approximately 15,000 acres in areal extent with 870 feet of vertical closure. The UI-UU1 reservoir is comprised of two sections that have some shared depositional and structural provenance. The western area, composed of upper shoreface and tidal deposits with good and predictable rock properties (e.g., sands have permeabilities from 2–5 Darcies), is informally referred to as the Bedded Biafra. The eastern section, which covers approximately two-thirds of the field, contains remobilized (e.g., slumps associated with mass movement and debris flow) and often deformed Bedded Biafra created by a shelf margin collapse. Popularly known as 'rubble beds', this structurally heterogeneous section is characterized by variable rock properties (e.g. permeability ranges from 0.1mD– 3 Darcies) and diverse deformation styles (e.g., discontinuous and randomly distributed facies). This interval, informally called the Disturbed Biafra, contains 70% of the field's remaining ultimate reserves (RUR) and is the major focus of the re-development effort.

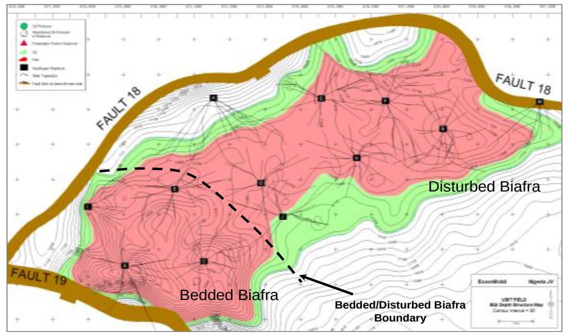


Figure 1. Ubit Field Base Qua Iboe depth-structure map.

Field Development Overview

Historically, development of the Ubit Field has been affected by a lack of understanding of the movement and fluxes of fluids in the reservoir, and the corresponding impact on productivity. This is most notable with respect to the Disturbed Biafra. To better understand fluid movements, the reservoir simulation model became the main driver for the revised field development plan (FDP).

Development of Ubit started without the benefit of a reservoir simulation model, horizontal well technology, inflow control devices, or an integrated asset level team. Early deviated production wells were plagued by high gas-oil ratio (HGOR) and high water-cuts (HBS&W) resulting from sub-optimal well placement and milled window completions. Conventional efforts to increase production performance through recompletion, re-drilling, and opening-up larger perforation intervals did not yield any appreciable improvement.

This performance issue became the impetus for a large scale data gathering and study initiative. The effort leveraged a rich dataset that includes: over 6700 feet of cores cut from 13 wells in different sections of the field, Repeat Formation Tester/Modular Dynamic Tester (RFT/MDT) data from 31 wells, check-shot data from 34 wells, 6 oil PVT samples, 1 gas PVT sample, and installation of 13 permanent down-hole gauges.

Several systematic studies were designed to determine the parameters affecting productivity in the field. Results of these investigations, summarized by Clayton et al. (1998), resulted in a change of development strategy (horizontal completions), leading to an increase in recoverable reserves, and production uplift. Advances in screen technology and inflow control devices also provided a substantial improvement in well performance/reliability over the last decade. More recent integrated full-field reservoir simulation models, material balance (MBAL), and geologic studies have identified infill potential to capture bypassed oil.

Government regulations require 800-meter spacing between Ubit wells. However, results from an exhaustive simulation study show significant bypassed oil at the end of life (EOL) of existing producers. This re-development plan was hinged on recovering this bypassed oil.

Methodology

The Ubit re-development plan represents an integration of independent studies aimed at understanding the nature of the reservoir. Sequence stratigraphy, facies characterization, structural framework, and historical production data were combined with information from the MBAL, full-field, and segment simulation models to revise the FDP.

Results from core and log analysis revealed significant facies variability, especially in the Disturbed Biafra. This diversity in facies impacts the fluid contacts in the field. A review of production data revealed that there is minimal aquifer influx. The material balance studies validated OOIP estimates of approximately2.4 GBO. The material balance model also confirmed the gas cap to be the dominant drive mechanism in the system, and corroborated the weak aquifer support implied by the production data.

Ternary plots from the reservoir simulation model indicated significant oil saturations at the end of life for existing wells. The plots also showed different saturation levels, suggesting there are undrained and poorly swept areas. Well-level simulation studies demonstrated that well life is prolonged by: 1) placing the wells at a standoff of 20–30% away from the current oil-water contact (COWC), and; 2) initiating gas-lift. Locating infill wells at a standoff of 20–30% from the COWC in un-swept areas yielded significant incremental oil recovery.

The field redevelopment plan (FDP) was created after identifying and documenting consistent patterns within and between independent studies. After gaining internal alignment with different asset level functions, several workshops were held with the industry regulator to share study results.

Full-Field Reservoir Simulation Model

The Ubit 1-UU1 full-field simulation was conducted using ExxonMobil proprietary software EM^{power}. The simulation model was built to: 1) integrate all available geologic and engineering data, and; 2) capture field-wide fluxes and movement of fluids and contacts to assess future reservoir performance. The simulation model is based on an upscaled geologic model that includes facies, porosity, and permeability of the reservoir units. Reprocessed seismic data was utilized and tied to well-based data. A sequence stratigraphic framework was developed and used to create environment of deposition (EOD) models that were invaluable in predicting reservoir and facies distribution.

The fine-grid 35-million-cell geologic model was up-scaled to 3.5-million-cells with around 362-thousand active cells. The effort was aimed at creating the most efficient grid to effectively resolve fluid flow in the model. This proved to be adequate for achieving an acceptable history match.

The model has seven defined rock types: 1) turbidites; 2) upper shoreface sands; 3) channel sands; 4) lower shoreface; 5) debris flow; 6) lagoonal facies, and; 7) shale facies. The turbidites, upper shoreface and channel sands are good-quality high-permeability sands. The lower shoreface, debris flow, lagoonal facies are poor-quality lower-permeability facies.

Capillary curves were assigned to each rock type. The capillary curves for high quality rocks are sharp and result in virtually no transition zone. Those for the lower quality lower shoreface, lagoonal, and debris flow rock types have a larger oil-water transition zone than the high quality rocks. Shales were treated as barriers to flow. Absolute permeability values range from 0.1 millidarcy–7 Darcies (most are 2–3 Darcies). These permeability values were derived from porosity-permeability relationships based on results from the study of over 6700 ft of cores cut from thirteen wells. The permeability curves for all the facies indicate a water wet system.

The fluid is typical saturated black oil. PVT analyses from six different wells show an average oil gravity of 36^{o} API. The mobility ratio is such that gas and water coning is problematic.

Geologic Case Impacting Well Placement

The basis for reduced well spacing was reached through a robust integration of geologic, petrophysical, and historical production data. Photographs of cores cut from wells in different sections of the Disturbed Biafra revealed different random patterns of rock deformation and quality.

Cores taken from thirteen wells distributed across the field further support the presence of major lateral and the vertical facies variations in the Disturbed Biafra. An example of the Disturbed Biafra rock fabric that impedes stratigraphic correlation between penetrations is illustrated in a core photo from the M8 well (Figure 2). Distinct stratigraphic markers can be correlated between wells within the Bedded Biafra. Reasonable correlation of disturbed Biafra wells is difficult-to-futile, even where the wells are just a few feet apart.

The impact of the stratigraphic variation on well performance, with respect to contact movements, is depicted in Figure 3. This structural schematic shows two wells (A and B) placed 800-meters apart. The wells are completed in high-quality sands and efficiently sweep hydrocarbon, as indicated by GOC movement. Areas of lower-quality sands within 800-meter space between wells are not completely drained before the producing wells quit because of either high gas-oil ratio (HGOR) or high basic sediments and water (HBSW). Reducing well spacing by placing well C between A and B enables efficient draining of these unswept areas of the field. This understanding of the stratigraphic heterogeneities was used to modify well landing and completion strategy resulting in a quantum leap in the recent successes recorded for this field.

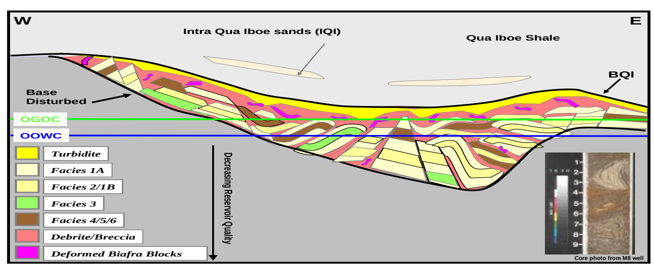


Figure 2. Schematic of facies distribution in the Disturbed Biafra.

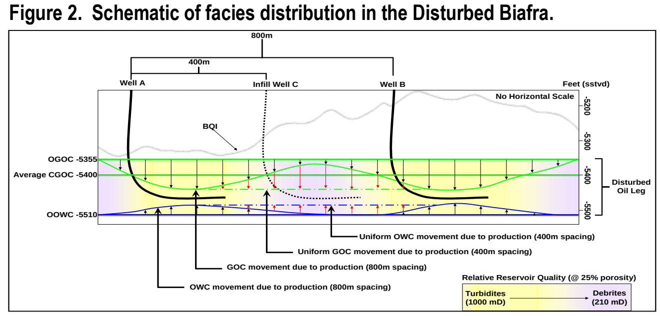


Figure 3. Impact of reservoir quality on contact movement and well spacing.

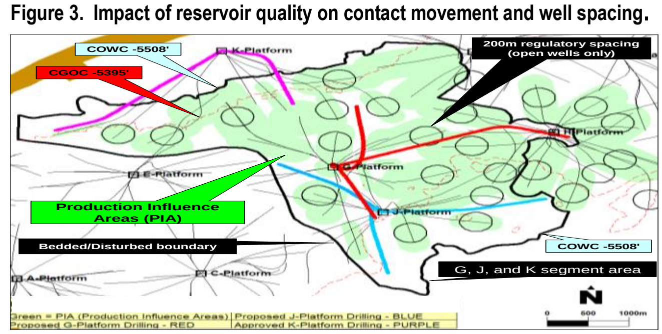
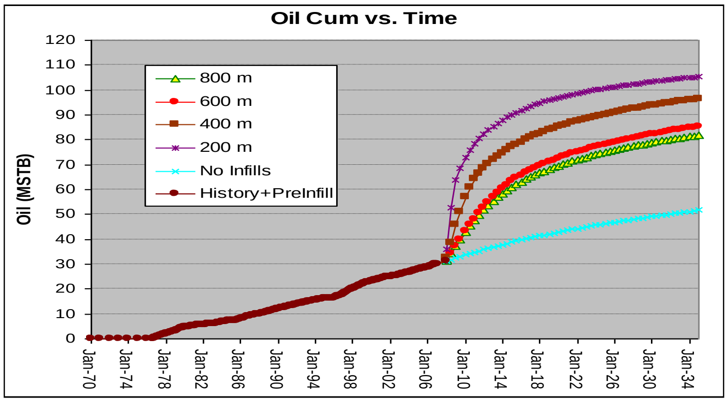


Figure 4. Use of the PIA concept for well placement.

Well placement was based on an innovative production influence area (PIA) assessment (green areas in Figure 4), which recognized the stratigraphic heterogeneity of the Disturbed Biafra. The PIA was derived from a combination of decline curve analysis and drainage area estimation. Cumulative production and expected future production from existing wells is used to estimate drained areas at end of well life. The regions outside the PIAs are the targets for new well placement.

Simulation Case

After the initialization and history match, oil saturation was tracked to end of field life. The results showed that after the end of life for the base wells there are significant undrained areas, and most of these are within 800-meters from existing producers. This was validated with segment models. The history-matched model (May 2009) shows significant bypassed oil saturation by 2040. Targeting these bypassed oil locations will require drilling 100 additional wells in the field. Segment models were built to optimize spacing, horizontal well length and standoff from the COWC. Results from all segments consistently highlighted the need to reduce spacing to optimize recovery from the poorly swept Disturbed Biafra. The H platform area example is shown in Figure 5.



History matching was achieved after eleven iterations. Oil saturations at the end of life of the existing wells in the H-platform area showed significant bypassed oil. The study recommended fourteen additional infill wells to capture an estimated 44 MBO, but well count was reduced to eight based on a specified economic cut-off.

Figure 5. Ubit H segment model results on reduced opening.

Material Balance Analysis

The material balance model estimates OOIP to be approximately 2.4 GBO with a large original gas cap (m ratio of 0.9 RB gas/RB oil. Gas cap expansion is the dominant drive in the reservoir with weak aquifer support. This reinforces the horizontal well landing strategy of 20–30% off the COWC for longer well life. Gas injection was initiated in 2006 for pressure maintenance and continues to augment the gas cap expansion as the main energy sources and displacement processes. Contact movement in the model matches the overall contacts observed in the recent drilling campaign.

Results

The simulation model outcome, and a better understanding of the random nature of the Disturbed Biafra section, formed the basis for updating the Field Development Plan to incorporate reduced well spacing. Information from independent sources, including geology and material balance studies are consistent with the reservoir simulation modeling results.

Well logs from Ubit H platform drilling confirmed the variability in the Disturbed Biafra. The H-platform area segment study predicted an incremental EUR of 29 MBO by reducing spacing from 800-meters to 400-meters with additional eight wells. The H-platform area infill drilling has been completed with encouraging results.

The simulation model results are consistent with actual production from the field. Figure 6 shows Ubit Field's production with and without infill drilling. Actual field production was layered on this illustration to emphasize the models predictive capability.

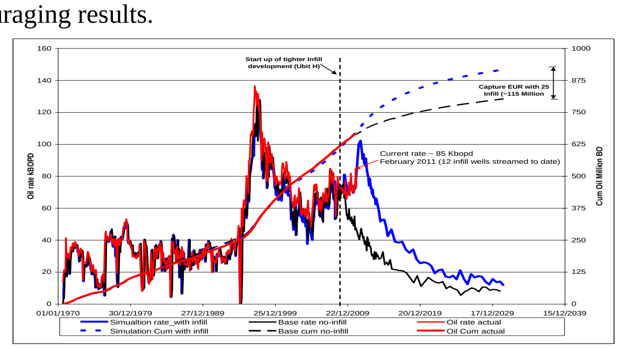


Figure 6. Ubit performance (Actual vs. simulation) EOLL

Conclusions

This paper chronicles the multi-functional collaborative effort undertaken by the Ubit team to optimize the FDP with better understanding of a complex reservoir. This study concludes:

- The Disturbed Biafra is a heterogeneous mixture of varying uncorrelatable facies types that severely impact recovery from the reservoir.

- The reservoir simulation model proved to be a useful tool in identifying bypassed oil and locating potential infill wells in a geologically complicated system. Reservoir and geologic modeling support the need for more infill wells at reduced well spacing to capture bypassed oil.

- Early results from the implementation of the revised Field Development Plan are very encouraging and consistent with model predictions. The simulation model is continuously being updated to reflect recent drilling results. Preliminary interpretation of recent seismic volumes supports simulation results and shows the model has sufficient capacity for future performance prediction.

Acknowledgements

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