Proactively Utilizing Ocean Bottom Node (OBN) Seismic to Unravel the Tectono-Sedimentary Complexities of a Shallow Offshore Niger Delta Reservoir to Drive Effective Business Decision during Project Execution

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ABSTRACT

The shallow offshore Niger Delta is one of the wealthiest Hydrocarbon Provinces in the world. Well positions and drilling decisions are based on detailed subsurface mapping using the latest available legacy seismic and other geoscience/Petrophysical data. Having the right data set to drive business decision remains key. In late life development of one of our assets in Shallow Offshore, several wells were planned to develop smaller accumulations within a complex structural setting. Further drilling in this field was hampered by unexpected unsuccessful early results. This costly surprise implied that any further work had to wait to include results of the processing of a recently shot seismic survey. The legacy seismic on which the initial map was based is a Streamer survey shot in 1988 while the new seismic is an Ocean Bottom Nodes (OBN) survey shot in 2018. This work is focused on understanding the difference and impact between these two surveys, by re-mapping the same structure on the OBN seismic, analyze why the wells failed and propose an alternative scenario. The OBN seismic is not fully processed but the Ultra "Fast Track" volumes were released for the analysis. Using these "Fast Track" volumes, a workflow was set up and used to refine different possible maps. Management was interested in the outcome as learnings will be deployed to prevent future suboptimal well results. As the resulting evaluation explained why the wells failed, technical reviewers considered that the results were sound and suggested to drill a new well based on the latest evaluation. A new well was successfully drilled, reservoir parameters matched predictions and initial production was estimated at ~2000 bblo/day. Results showed that the structure is much smaller than what was initially interpreted on the streamer seismic. Hence, plans to drill more wells into the structure was dropped.

KEYWORDS: Seismic, tectono-Stratigraphic, Reservoir, Ocean Bottom Nodes, Contact, progradation, Modelling

INTRODUCTION

The study reservoir (M1B) is a Miocene sandstone, deposited in the transition between the delta plain and slope, in a crestal collapse structure of the shallow offshore, Niger Delta (Figure. 1). A first phase field development in the early 2000's, drilled seven wells with five sidetracks, targeting different reservoirs in a multiple reservoir seal pair system. The results were not satisfactory – several reservoirs were wet – clearly the understanding of the geometry and the depositional architecture was not correct. For the M1B reservoir, only one well (Well 4) logged the Oil Water Contact (OWC) at the flank of the structure creating uncertainty on the extent of the accumulation and the hydrocarbon column (Figure.2).

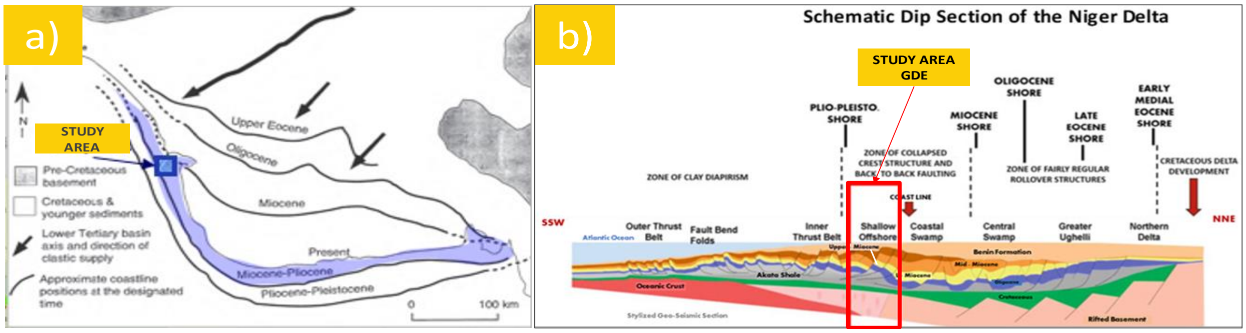

Figure 1a *(left): N. Delta Progradation Cartoon showing the study area; modified: Whiteman (1982).* ***Figure 1b*** *(right): Schematic Dip-Section of the Niger Delta showing the structural system and depositional architecture of the shallow offshore depobelt (red rectangle). Regional stratigraphy: light Orange: Benin; Brown -Orange & Yellow: Agbada (Miocene); and Gray: Akata (After Shell 2007; Weber and Daukoru 1975) Niger Delta showing the structural system and depositional architecture of the shallow offshore depobelt (red triangle) (After Shell 2007; Weber and Daukoru 1975)*

The seismic data that underpinned the first drilling phase was acquired in 1987/88 via a streamer with a 3km cable length and 48-fold coverage. This seismic data suffered from very poor imaging that led to multiple reprocessing and interpretations, the latest being 2018 PreSDM. Using this re-processed seismic, a second development drilling phase commenced in mid-2019, which planned 3 horizontal oil wells to develop the M1B reservoir.

To help de-risk the huge hydrocarbon column uncertainty in the M1B reservoir, a pilot hole was planned to appraise the fluid type and contact at the crest of the structure, 1km away from the initial well that logged the OWC (well 4). This pilot hole (PH1) will help plan the landing of the three horizontal wells in the M1B reservoir (Figure 2).

When drilled, PH1 was "thought" to have logged an OWC at approx. 100 ft TVD, shallower than previous OWC. Fluid and pressure samples were acquired from the well for laboratory analysis. An immediate operational interpretation of the fault pattern suggested that PH1 was probably in a different, isolated fault block, which explains the difference in fluid contact. It was nevertheless decided to proceed with the drilling of the first planned horizontal well (HW1), targeting the same fault block as Well 4. Unfortunately, the well encountered the reservoir wet. The drilling of the remaining two (2) horizontal wells (HW2 and HW3) was suspended until the M1B's depositional and structural models are validated with the recently acquired Ocean Bottom Node (OBN) 3D seismic, which is the focus of this study.

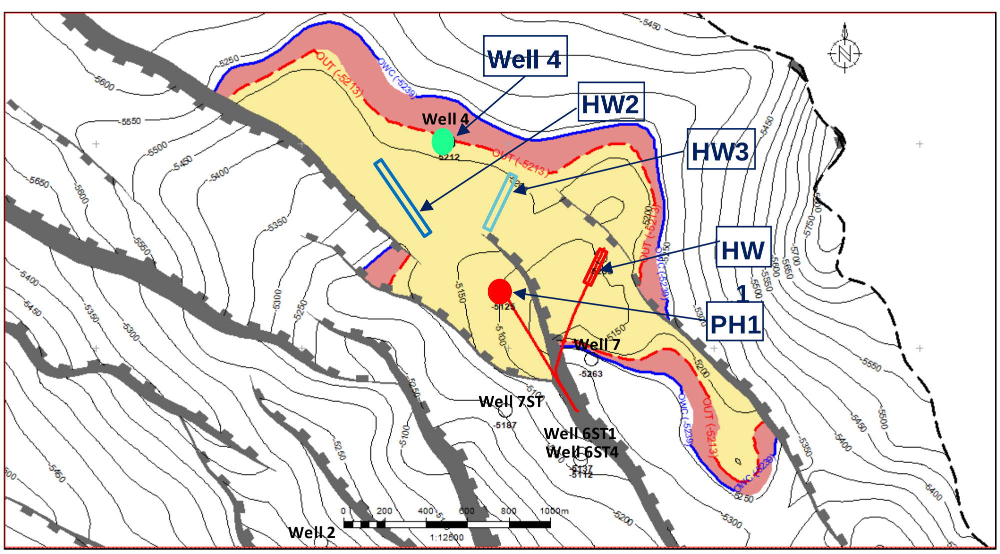

Figure 2 *Structural Map with fluid fill type (Yellow: undifferentiated; Red: Oil), and well locations. The well details are explained in the text. PH1 and HW1 were drilled in the second campaign and resulted in surprising results which challenged the accuracy of this map. This is based on Streamer seismic data that underwent several re-processing phases. The latest being 2018 PSDM.*

This recent OBN seismic acquisition used 6km cable length and 480-fold coverage. It was processed in 2020 using Kirchhoff migration with Full Waveform Inversion (FWI) and Velocity Model Building (VMB). The new seismic data shows significant improvement in the seismic imaging – event continuity, structural definition and amplitude expression. However, correcting for multiples and noise in the shallow water was challenging; this will be mitigated with Random Noise Attenuation (RNA) filters as part of the seismic interpretation workflow. Figure 3 shows the improved imaging quality of the OBN seismic when compared to the 2018 PreSDM (Streamer) seismic.

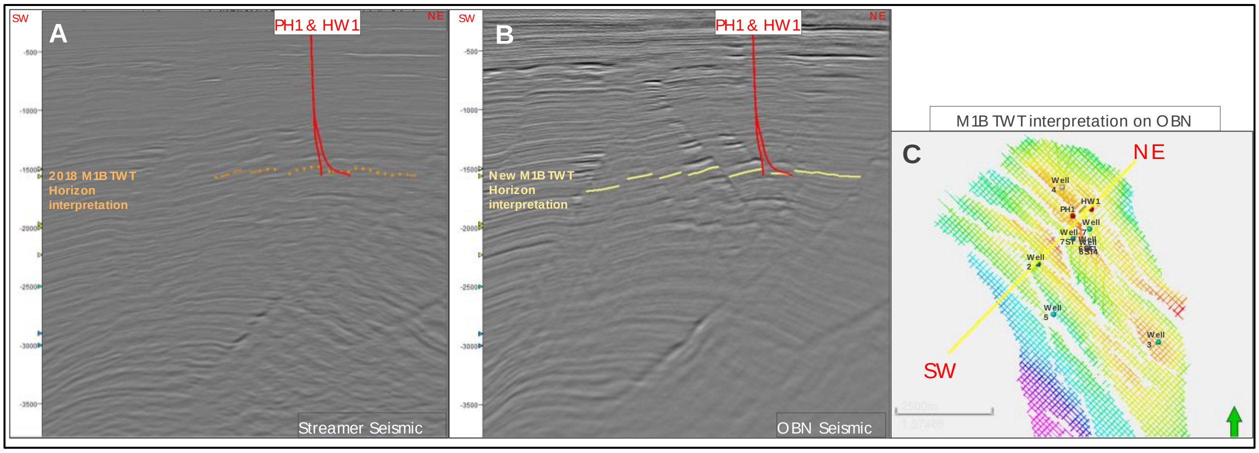

Figure 3a *(left): Un-interpreted dip seismic section though PH1 and HW1. Note the poor migration of the Streamer seismic below 1.6 secs.* ***Figure. 3b*** *(center): Same line of section as 2a. Observe the improved signal to noise ratio, frequency content and event continuity on the OBN seismic when compared to the legacy seismic.* ***Figure 3c*** *(right): TWT horizon interpretation of M1B on OBN seismic showing the line of section of the cross-section and the distribution of the wells in the field.*

The aim of this project is to update the existing M1B structural model, explain the reasons for failure of the previous wells and determine the drilling or not of the remaining two (2) horizontal wells using the new OBN 3D seismic by:

- Interpreting the faults and horizon of the target reservoir on the OBN seismic volume, incorporating the recent drilling results to understand the structural complexity and deformation style.
- Reviewing the different seismic processing versions and utilizing what is “geological” from each.
- Building a 3D structural model in Petrel incorporating all available data and interpretations.

LITERATURE REVIEW

The Niger Delta is one of the largest modern delta-systems on earth. The occurrence of gravity driven deformation related to overpressure shales is well known. The Niger delta has a distinctive structural and stratigraphic zonation. Regional and counter regional growth faults, developed in an outer-shelf and upper-slope setting, are linked, via a translational zone containing shale diapirs, to a contractional zone defined by a fold-thrust belt that developed in a toe-of-slope setting (Durogbitan, 2016).

Structurally, the study area lies within the transition between the delta plain and slope, in a crestal collapse structure of the shallow offshore, Niger Delta Figure. 1b. Although it is a prolific Hydrocarbon province, trap integrity, hydrocarbon column height and the possibility of relay ramp zones pose a significant impact on Hydrocarbon fill in many fields.

Rouby (2011) explored the implications of the migration of the delta front on the kinematics of gravity driven deformation, in a case where the stratigraphic framework is detailed enough to discuss deformation kinematics and sedimentary supply at high temporal resolution (×0.1 Myr).

Hooper (2002) observed that a complex paleo fold belt is buried under the modern upper/middle slope. As the shallower ponded slope-basin were progressively filled, the previously deposited strata modified the accommodation and subsequent depositional systems compensated accordingly. Similarly, Chima (2019) used calibrated seismic facies to describe the depositional architecture of the Neogene "filled ponded basin" in the Niger Delta's upper slope.

The study field is part of the well-known stratigraphic formations of the Niger Delta shallow-water: i) Akata, ii) Agbada and iii) Benin (Figure. 1). The evolution of the Niger Delta controlled by pre- and syn-sedimentary tectonics is described in detail by many authors. Accommodation space created during the Late Cretaceous rifting filled by poorly compacted, over-pressured, prodelta and delta-slope shales, clays and silts of Akata Formation, followed by the delta-front, paralic interbedded sandstone and shale of Agbada Formation. The gravity tectonism was continued during the Tertiary Agbada and Benin formations and are developed into complex structures, including roll-over anticlines, collapsed growth fault crests, and high angle normal faults.

The stratigraphic framework of the study is established by identifying flooding surfaces, picked on the e-logs signatures and biostratigraphy studies (Figure. 5). The sands of the 'Shelf-Shallow Offshore Belt' have been deposited during the progradation process, which became progressively younger in the seaward direction

EVALUATION AND METHODOLOGY

Following the surprising results of wells PH1 and HW1, a re-evaluation was required before making any additional commitments. The recent well results, the newly acquired and processed OBN and the log data are the critical input. The fluid contact uncertainty needed to be understood: is it driven by a more complex faulted scenario and a different velocity model that impacts the interpretation or a poorer seismic image that resulted in the wrong map?

Proposing an alternative map interpretation that could explain what happened with the two wells is essential to make decisions regarding another investment. This is the specific focus and major objective of this study.

Figure 4 shows the iterative Structural Interpretation Workflow that was used as the intermediate results of the OBN processing seismic were made available:

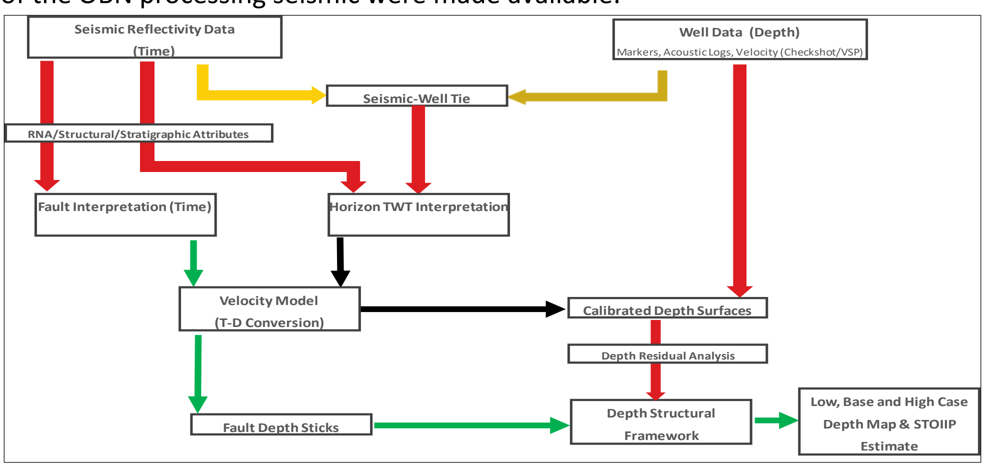

Figure 4 *Workflow designed to carry out multiple iterations using the intermediate processed volumes from the OBN seismic. This workflow leads to delivering a final map which was used to explain the surprising results and to make new decisions leading to the successful drilling of an additional oil producer.*

OBN seismic acquisition and processing: The seismic data was acquired with the Nodes on a Rope technology or OBN in 2019 with 6km cable length, 480-fold coverage and 9000ms record length. The main benefit of the OBN over the streamer legacy acquisition method is the ease of multiple attenuation, giving the data a more accurate imaging of the subsurface. The key challenges encountered during the OBN acquisition that directly impact the data quality are 1) under-shoot around existing facilities, 500m offset from the Floating Production Storage and Offloading (FPSO) & Platforms and 2) fishing activities –nodes dragged out position resulting to data deterioration around those areas. The OBN seismic data was processed in 2020 using Kirchhoff migration with Full Waveform Inversion (FWI) and Velocity Model Building (VMB). The new seismic data shows significant improvement in the seismic imaging – event continuity, structural definition, and amplitude expression (Figure 1b). However, correcting for multiples and noise in the shallowest water was a challenge; this was mitigated with RNA filters as part of the seismic interpretation workflow.

Structural Framework: The M1B reservoir structure is a crestal collapsed rollover anticline, dissected by a system of semi parallel NW-SE trending synthetic and antithetic faults in semi parallel fault blocks. It is separated from the adjoining field by a major boundary fault. Hydrocarbon accumulations are typically elongate and parallel to structural and depositional strike. The trapping element within the M1B reservoir block is 3-way closure with a synthetic normal fault. Fault cut-out interpreted from the well logs was integrated in the structural model (Figure 2).

Stratigraphic framework: The M1B sand is interpreted as tidal channel and shoreface deposits ranging in thickness between 60-80 ft TVD. It comprises of mainly 2 para-sequences separated by minor flooding surfaces. Generally, reservoir packages show lateral continuity and good sand development while the shaly units are expected to constitute baffles to vertical flow. Biostratighraphic study show that the M1B reservoir lies within the Upper Miocene, Messinian (Me-2) sequence between the 5.0Ma MFS and 5.6Ma SB in the Transgressive System Tract of the 3rd Order sequence stratigraphic interpretation of the study area (Figure. 5). Four Parasequences constituting progradational to aggradational sets were analyzed and found to be consistent when integrated with the 3rd Order sequence stratigraphy.

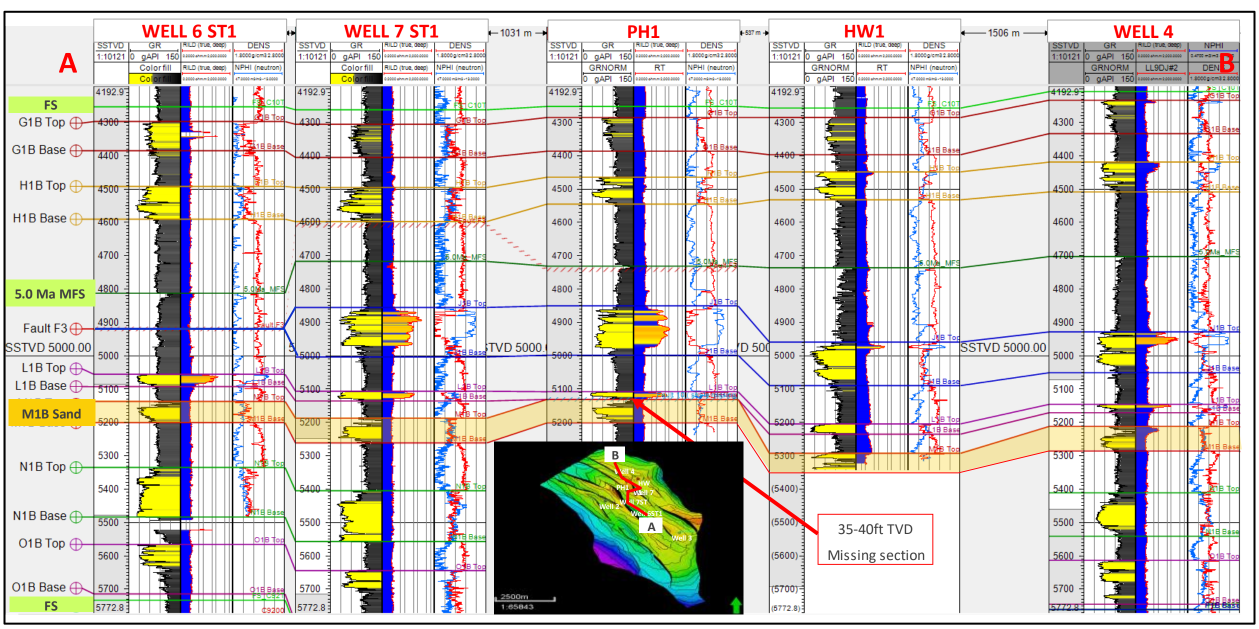

__Figure 5__ Stratigraphic correlation of key wells in the field. Detailed bio-stratigraphic and sequence stratigraphic analysis are crucial to establish the correlation. The presence of fault cut is readily noticed when regional correlatable units have sudden changes of thickness. These fault cuts have been tied to the fault interpretation. The red arrow points to the missing section just above M1B sand which was responsible for the erroneous fluid/contact initial interpretation on PH1.

Reservoir Properties and Fluid Distribution: Evaluation of available suite of well log data, pressure and fluid samples was carried out by the Petrophysicist. There were 7 well penetrations in the reservoir prior to the drilling of the PH1 and HW1. The existing field correlation was updated with the information of the recently drilled wells. The top of the M1B reservoir sand is dominated by a correlatable radioactive sand with possible presence of heavy minerals as seen by the density log response (Figure. 6). M1B reservoir property is generally of good quality. Well 4 encountered the M1B reservoir hydrocarbon bearing at the NW flank of the structure. The well logged an Oil Up to (OUT) at 5213 ftss and OWC at 5239 ftss giving a known 26ft oil column with 149ft undifferentiated hydrocarbon column from the OUT to the crest of structure (Figure. 6). PH1 was initially interpreted to have logged an OWC circa 100ft TVD shallower than well 4 at 5130 ftss creating a huge uncertainty in the fluid type and contact. However, on further review of the correlation, fault cut-out on well logs and pressure sample results, that understanding was revised. Details of the revised interpretation is given in section 4.0.

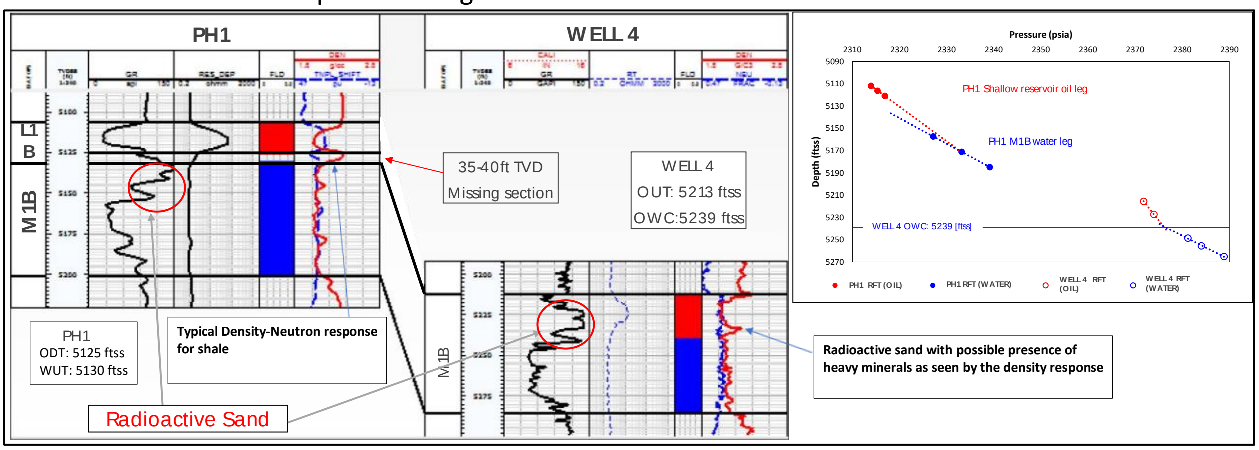

__Figure. 6:__ Log correlation for wells PH1 and Well 4, focused on the M1B sand, in different tracks: Gamma Ray (GR); Deep Resistivity; Fluid Interpretation (Red: oil - Blue: water); Neutron (blue)Density(red). Note the Effect of the Radioactive Sand which appears in the GR as a shale, but when analyzed with the neutron-density it shows the same behavior as the deeper sandy interval (known behavior in the delta). The inset plot on the right compares the pressure data points and interpretation based on different gradients. Well 4 and PH1 are clearly in different pressure domains and have different water gradients.

Seismic Attribute Analysis: Random Noise Attenuation (RNA) filters were applied to the OBN seismic to reduce the noise. Structural and stratigraphic highlighting attributes, coherence, amplitudes, and spectral decomposition were extracted and used to improve fault and horizon interpretation. Amplitude analysis could not be used for fluid type and contact estimate because there are no clear DHIs and reliable amplitudes that are conformable to structure on the M1B reservoir level.

Well to Seismic Tie: Synthetic seismograms were generated by the Quantitative Interpreter (QI) using sonic and density logs calibrated with checkshots from well 3 and 4, located at the SE and NW flanks or the M1B structure respectively (Figure. 7a). The result shows very good synthetic-seismic correlation requiring only an 8msec time shift to achieve a tie. The good match obtained between synthetic and seismic was used to identify key well markers on Well 4 and 3 and the M1B loop on the OBN zero phase reflectivity seismic.

Fault and horizon Interpretation: One of the key markers identified from the well-to-seismic tie was the 400ft thick regional shale unit containing the 5.0 Ma MFS above the M1B reservoir. This shale marker corresponds to a hard kick on the seismic. Similarly, a gas bearing reservoir (J1B) above the M1B reservoir but below the regional shale marker (Figure. 5), corresponds to a soft kick on seismic. These two markers show very clear acoustic impedance contrast resulting to a very high amplitude expression that is easily identified and traced on seismic. However, at the M1B level, the amplitude expression is not distinct and poorly resolved in some parts, probability due to some sub-seismic stratigraphic and /or structural imprint leading to difficulty in M1B loop interpretation. To improve the seismic image resolution, post processing noise reduction filter was applied to the seismic data. The improved imaging quality of the OBN seismic enhanced the discontinuities in the field. On the extracted coherency attribute slice, faults are clearly highlighted and were integrated to further improve the fault interpretation (Figure 7). In addition, fault cut out interpreted on the well logs were used to tie the interpreted fault position and increased the confidence of the lateral fault position in the field.

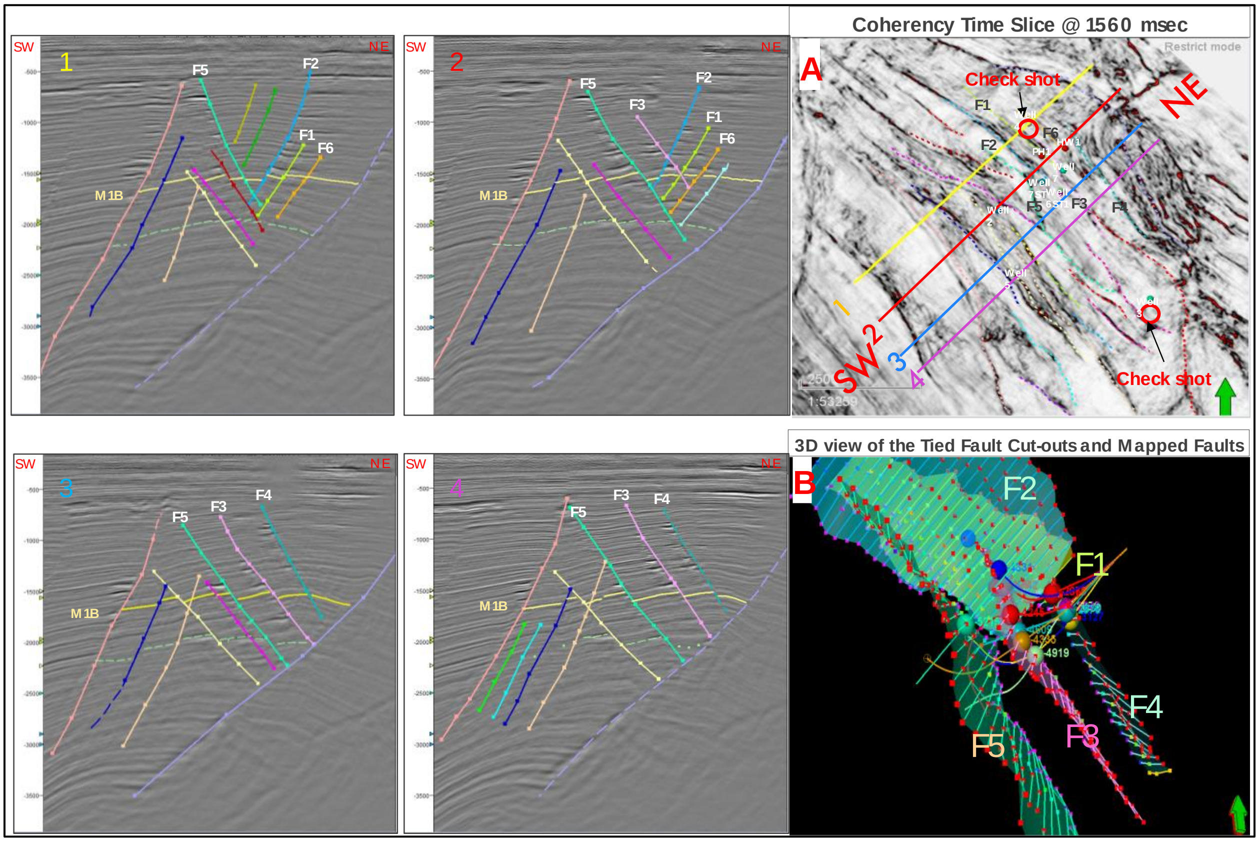

__Figure 7__: A series of seismic lines 1-4 (OBN) with fault and horizon interpretation within the Area of Interest. __Figure 7a__ (top right): The location of the seismic lines is on the Coherence time slice which helped tune up the mapping (dotted lines) of the faults. The main faults contributing to the hydrocarbon trap are numbered for easy identification. The position of the wells with check shots are highlighted. __Figure. 7b__ (bottom right): Fault cuts identified on the well logs was used to tie the lateral position of the interpreted faults. A 3D perspective helps to enhanced visualization of the complex fault relationships and emphasizes the importance of working in the 3D domain.

Velocity Modeling and Time-Depth Conversion: Two velocity modelling methods were analyzed for a suitable time-depth conversion. Since there is limited lateral variation of the pseudo-velocity from surface to target depth, the Polynomial method which gave low average well residual of 15ft TVD and one standard deviation (STD) of 29 ft TVD was used for the depth conversion.

Depth Structural Model and Stock Tank Oil Initially in Place (STOIIP) Estimate: Using the Petrel Modeling software, the depth converted faults sticks and M1B horizon were used to generate a 3D structural model for the M1B reservoir. STOIIP range estimates were calculated using average petrophysical and fluid properties from the existing wells and used a basis for the critical business decision.

RESULTS

The first stage of the work consisted in analyzing the different results of the OBN seismic processing. Within a strict timeline, the Geophysics Processing team was tasked to deliver “Fast Track Volumes” and velocity models to help with the on-going drilling campaign. To improve the seismic image in a final PSDM volume that will be used to generate a map that explains the surprise drilling results, the team adopted different workflows and constant feedback from the interpreter was crucial. Figure. 3 and 7 show that after many iterations, the final product provides far better resolution that improved fault and horizon interpretation. Post processing noise reduction filters and fault and horizon highlighting attributes were applied to the zero-reflectivity seismic to improve the interpretation.

PH1 was the first well to be drilled during the mid-2019 campaign. The objective was to help de-risk the 149ft TVD hydrocarbon column uncertainty in the M1B reservoir (Figure. 2). Post drill, PH1 was initially interpreted to have logged an OWC circa 100f TVD shallower than existing well 4, creating further uncertainty in the structure, fluid type and contact. Well HW1 was then drilled with the hope of landing on the same fault block as well 4 but it unfortunately encountered the reservoir wet. Further review of all available data caused a revision of the earlier interpreted oil column on PH1.

On the well correlation, five major faults (F1-F5) were observed to be responsible for the fault cut seen on the well logs (Figure. 5). These faults cut outs were carefully integrated in the fault interpretation to increase the confidence of the lateral fault positions on the new map. However, the 35-40ft missing section above M1B reservoir seen on PH1 (Figure. 5 and 6) that resulted in the shallower HC bearing reservoir to directly overlie M1B, making it difficult to pick the top of M1B remains unresolved as no seismic fault or stratigraphic feature could be interpreted due to vertical resolution of the seismic data vis-à-vis the thickness of the missing section. But the result of the acquired pressure sample across the oil and water column on PH1 showed that the water gradient for PH1 and Well 4 are different (Figure. 6), implying that they are different reservoirs. This led to the revised interpretation that PH1 encountered the M1B reservoir wet just as HW1.

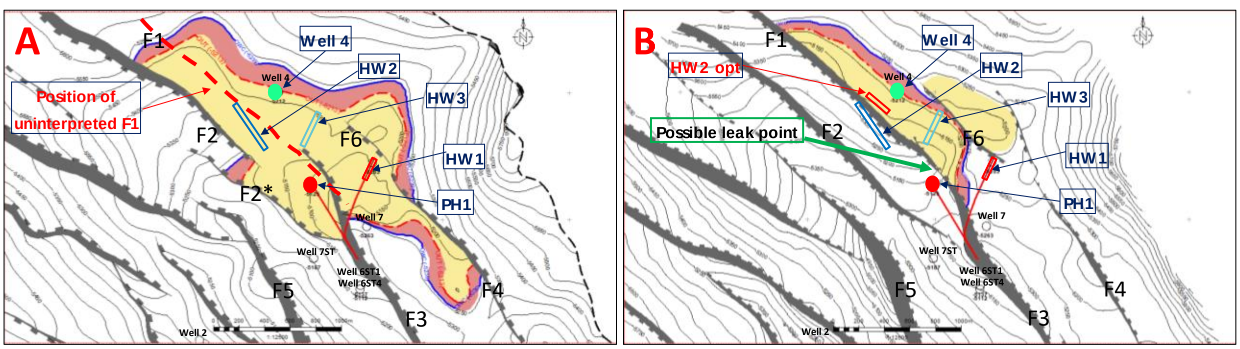

Figure 8*: Final comparison of the legacy map used to drill wells PH1 HW1 and the new map resulting from this Study.* ***Map A****: Legacy map based on the Streamer seismic.* ***Map B****: New map based on the latest delivered processed OBN. The map shows some differences in fault position in 3D space. Map B also shows an easier to explain structure where the oil accumulation is mainly controlled by Fault 1 (F1). The structural geometry of Map A has many issues that were difficult to explain but was the result of working on seismic with poor fault definition. See detailed discussion in the text.*

Figure 8 shows a comparison of the maps based on Streamer (A) and OBN (B) seismic. The latter is one of the many realizations with best structural geometry that integrates the understanding of the newly available data in M1B reservoir. Map A shows a large structure with very limited controls to the NW and part of the SE. This should had been a warning and a smaller scenario should have been considered for volumes. Map B on the other hand, confirmed that the SE nose of the map does not exist. Map B also shows that the structure is mostly controlled by fault F1 (which was not interpreted on Map A) rather than a series of small faults as it is shown in Map A.

Map B does confirm the presence of F3 (the lateral position is confirmed by well log fault cut on PH1, Well 6ST and 7ST (see Figure 5 well correlation)), but this fault is at the same trend as F1, hence it is involved in the definition of the structure; but as the faults grew laterally and because F1 and F3 have different vergence, they appear to connect, defining the potential point of leakage of fluids which explains the possibility of having the PH1 wet even though it penetrated a structural high. This is a well-known issue in the Niger delta that structural locations of fault convergence or small relays can become points along which fluids can escape. This is one of the explanations of why almost 90% of fields in the delta are under filled (Mora-Glukstad, 2016).

Also, the STOIIP estimate of Map B shows significant reduction of up to 70% when compared with Map A, threatening the success of the earlier proposed wells HW2 and HW3.

DISCUSSION

Following the Structural interpretation workflow of Figure. 4, different scenarios of maps were generated. The well constraints provided by the two latest wells (PH1 and HW1) were crucial to improve the previous map, but there is always uncertainty regarding fault geometries with limited well penetrations. The key challenge of understanding the observed different fluid contacts is controlled by the structural interpretation and the velocity model. It was obvious that the way we choose to map the faults makes the remaining volumes either attractive for additional well opportunity or potentially un-economic and the velocity model would either bring the structure deeper or shallower. Fortunately, well 4 provides a very strong anchor point. Unfortunately, well PH1 is drilling potentially into a fault zone and the actual fluid contact could be totally disconnected from that of well 4. The information from well HW1 was crucial in picking a velocity model that "pushed the structure down" and provides a better match with new well results.

With this new understanding of the available data, the structural kinematics of the resulting map is heavily challenged as it implies that the structural crest of the reservoir is wet, and the previous understanding of trapping mechanism in doubt. The data acquired and evaluated helped reduce some of the initially identified uncertainties but the critical uncertainty for which PH1 was drilled remains, fluid type/contact up dip of well 4. The new map (Map B) shows possibility of some isolation of the NE horn of the HC fill which will likely further reduce the estimated in-place volume.

This study hence provided additional proposal for Shell Petroleum Development Company (SPDC's) leadership to consider. The proposal was focused on recoverable volume estimate and business analysis which led to the decision to proceed with an accelerated drilling of only one optimized highly deviated well (HW2-opt) into the M1B reservoir (see location of HW2-opt on Figure. 8 Map B). Since the top holes for the initially planned wells were already drilled, and the rig was available, HW2-opt was drilled successfully in less than 15 days. The well found the top of M1B reservoir as prognosed, proved 70ft TVD of oil column and initially produced about two (2) thousand barrels of oil per day.

CONCLUSIONS

New seismic, either re-processed or recently shot does not always imply better results. Careful analysis of the cause of poorer results in legacy data, better understanding of the structural grain and the choice between OBN or streamer and the geographic conditions of the AOI (i.e., onshore, shallow offshore or deep water) is crucial. The implications of making the right choices have major financial impact. Based on this study, what allowed for an improvement of the seismic image was the integration of the existing data and the several iterations to generate workflows to test concepts and scenarios for a more robust outcome.

The structural interpretation and modeling of the M1B reservoir has caused us to challenge a single scenario result and the main conclusions are.

1. There is a need of a workflow that allows for different iterations which change and improve also as new versions of the seismic processed was delivered. “Never fall in love with your interpretation”; We had to challenge many different outcomes seeking better structural consistency and overall trap geometries. Even the “final” map has a degree of uncertainty.
2. The understanding of the behavior of this type of large-scale roll over anticlines with their associated crestal collapse faults is essential. Rapid changes of throw; faults which change vergence; relay systems, often narrow, and difficult to map, are almost a mechanical requirement that accommodates the complex deformation. If this is not properly understood, the interpreter will find it very difficult to map faults consistently.
3. The impact of the velocity model and migration algorithm is very important for fault position in 3D space. The comparison of the fault locations between the Streamer and OBN shows that some faults move laterally in 3D space and with different dip directions. The lesson learned is that the lateral uncertainty used for the faults in the first phase of drilling was seriously under-estimated.
4. Drilling campaigns require rapid response to un-expected surprises. The cost of the drilling rig makes it a big difference to be able to follow a workflow which facilitates having alternative interpretation with clear well constrains. This project became a lifeline in the decision making and not only allowed to continue with the drilling sequence but also proved to be technically correct and provided SPDC with a successful well which is now producing two thousand barrels of oil per day.

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