Building Realistic Velocity Model and Providing High-end Imaging to the Business: A Case Study ofKoloCreek, Nigeria, Onshore Niger Delta

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ABSTRACT

In this paper, we look at how reprocessing, building robust velocity models and advanced imaging techniquesare deployed on legacy seismic datasets fields, onshore Niger Delta, Nigeria to add business value. The pre- processing entailed using technology of broadband processing (low frequency boost processing). The broadband processing implied preserving the low as well as the high frequencies in every step of the processing with greater emphasis on the low frequencies. Low frequencies are essential because low frequencies are less attenuated compared to the high frequencies and as such image the reservoir levels and deeper prospects better. Also, for inversion to be robust, the low frequencies are very important as it reconfigures the acoustic response of the Earth more than the high frequencies. Velocity model building approach involved using the Full Waveform Inversion (FWI) for the shallow section, Sonic Velocity Model Building (SVMB) for the Deep and conventional Travel Time Tomography (TTI) for correct for Residual Move-Outs (RMO). Also, the Reverse Time Migration (RTM) algorithm was used for the seismic imaging. Deploying the FWI and incorporating geology from Sonic and TTI led to detailed velocity model with geologic which gave rise to an improved imaging resulting in a better definition of structural and stratigraphic features within the field. This seismic is aided the successful drilling of a just concluded well in the field, well planned for drilling in the next couple of months, with a huge, estimated recovery of gas.The biggest uncertainty in the area is structure, with this new RTM volume, the structures (faults) are better defined.

Keywords: Velocity, Imaging, Model, Residual, Migration, Algorithm, Full Waveform Inversion

INTRODUCTION

The oil industry as we know in recent times have been faced with realities of low oil price and operating in difficult terrain, with challenges to acquire new seismic data. Exploration drive is going deeper into the basinand the need for infill wells have become essential for assets and ullage utilization. Following from this, a better resolved broadband seismic image is essential in understanding hydrocarbon fields and unlocking more reserves.For proper seismic interpretation to take place, clearly understanding the stratigraphic features to map is key to delivering the structural framework and thus delineating the reservoir architecture.

This is tied to having good event continuity and true amplitude in the seismic dataset. Due to industrializationand cost-cutting, reacquiring new seismic data is not as easy as it used to be, therefore there is need to use advanced technology to derive more value from existing legacy seismic datasets. In this paper, reprocessing two already existing seismic datasets with recent technology (broadband processing and more detailed velocity model building) have shown more structural and stratigraphic features which were not clear in the legacy seismic ofthese fields, onshore Niger Delta, Nigeria. In this paper, we look at how reprocessing, building robust velocitymodel and advance imaging techniques are deployed on legacy seismic datasets, onshore Niger Delta, Nigeriato add business value. Find below the seismic acquisition parameters for the survey areas.

1	Year of Acquisition	2019	2008
2	Fold	312	54
3	Number of receiver lines	12	6
4	Receiver line spacing	350m	500m
5	Source line spacing	350m	600m
6	Bin size	25x25m	
7	Maximum offset	10km	6km
8	Record length	10s	6s
9	Source Type	Dynamite	
10	Receiver Type	Geophone & Hydrophone	

- Acquisition parameters are very different.
- Need to derive each survey's wavelet for the multi-

METHODOLOGY

Pre-processing

The pre-processing entailed using technology of broadband processing (low frequency boost processing). The broadband processing implied preserving the low as well as the high frequencies in every step of the processing with greater emphasis on the low frequencies. Low frequencies are essential because low frequencies are less attenuated compared to the high frequencies and as such image the reservoir levels and deeper prospects better, (Shell Technical Report, 2013). Also, for inversion to be robust, the low frequencies are very important as it reconfigures the acoustic response of the Earth more than the high frequencies.

Velocity Model Building

Velocity model building approach involved using the Full Waveform Inversion (FWI) for the shallow section, Sonic Velocity Model Building (SVMB) for the Deep and conventional Travel Time Tomography (TTI) for correct for Residual Move-Outs (RMO), (Shell Technical Report, 2017). Also, the Reverse Time Migration (RTM) algorithmwas used for the seismic imaging.

The strategy for the velocity model update (Figure 1) was to take advantage of recent technologies in deriving a model that is optimal for both imaging and time-to-depth conversion: Full waveform inversion (FWI) is an inversion process that considers wave propagation in predicting high resolution velocity. Penetration of the velocity model is expected to be between 3-3.5km for a 10km cable length. While Sonic based velocity modelbuilding (SBVMB) is a process of building a starting velocity model that has reliable input from the wells (sonics, markers, etc). This will result in a velocity model that will be beneficial for imaging and time-to-depth conversion (best of both worlds). FWI will provide the velocity model at the near surface where most wells do not have measurements from (reservoir levels). The FWI model will be the input into the SBVMB which will populate the deeper sections with velocity data from wells (sonic logs). These methods will output an initial velocity modelwhich will go through at least one part of travel time inversion. Figure 1 below shows the strategy used for velocity model building.

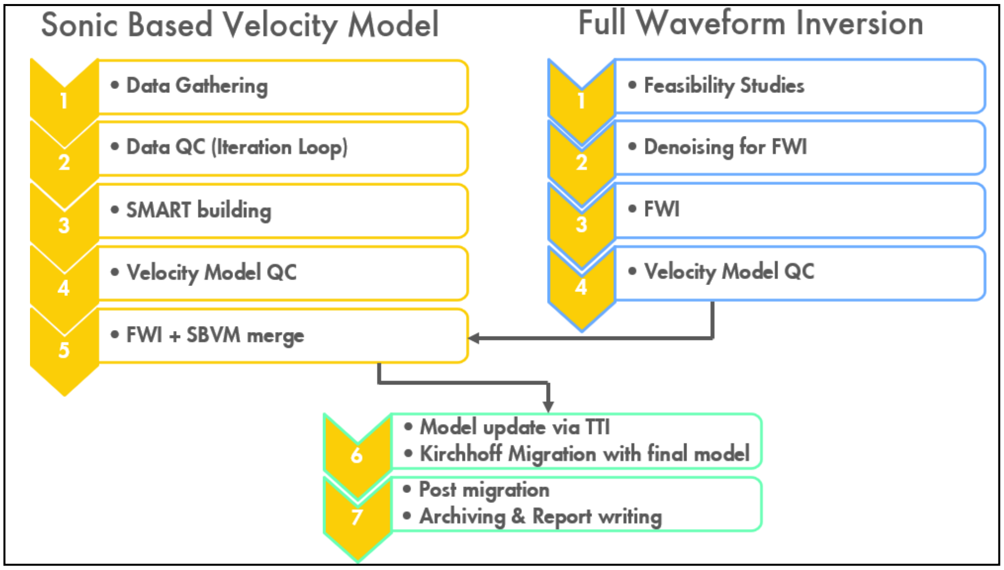

Figure 1: Velocity model building strategy

Full Waveform I nversion (FWI)

Feasibility studies were carried out to find out nominal depth of penetration and the optimal parameters for FWI. Since the dataset is a merge a multi-wavelet FWI was carried out. Figure 12 shows the test for depth of penetrationwhich resulted to about 2km for survey A and 2.5km for survey B with possible deeper penetration. The dataset for FWI must meet some requirements to optimally invert for the near surface velocity and/or other geophysical attributes (see Figure 2 below).

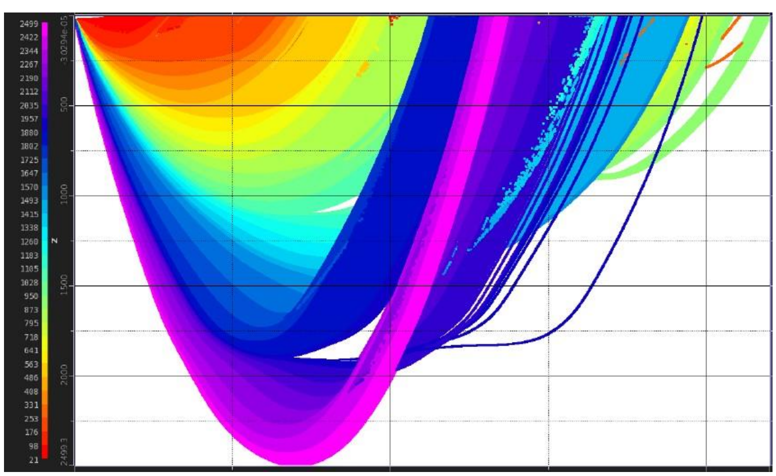

Figure 2: FWI Depth of penetration results

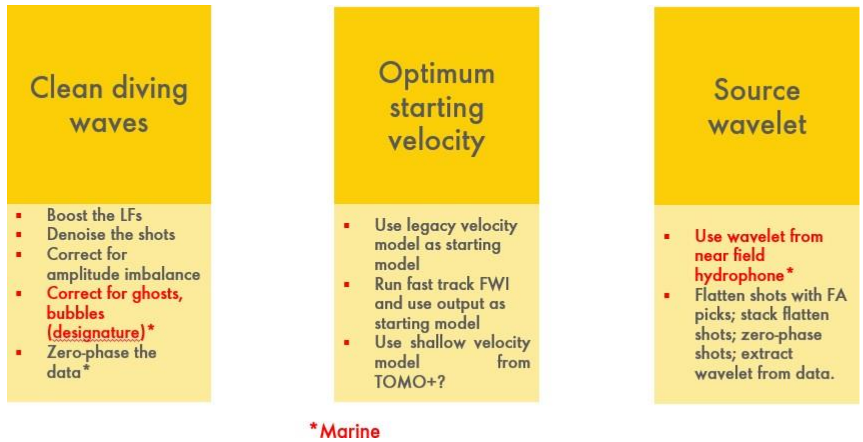

Figure 3: FWI data requirements

It is important to note that this is the first ever dual-wavelet FWI (two surveys) onshore Niger Delta. The legacy velocity model extending from survey A to B was used as starting model. It is also essential to prepare the dataset properly for FWI convergence to be attained, (see figure 3 above for a typical data requirement).

Firstly, the shots are denoised to attenuate high amplitude noise. Subsequently, first arrivals (FA) which are required to flatten the shots prior to stacking were picked using a refraction statics tool and exported from thetool. Next, the shots were flattened with the FAs, zero-phased and wavelet extracted from them. Figure 4 below shows the outcome of the wavelet extraction.

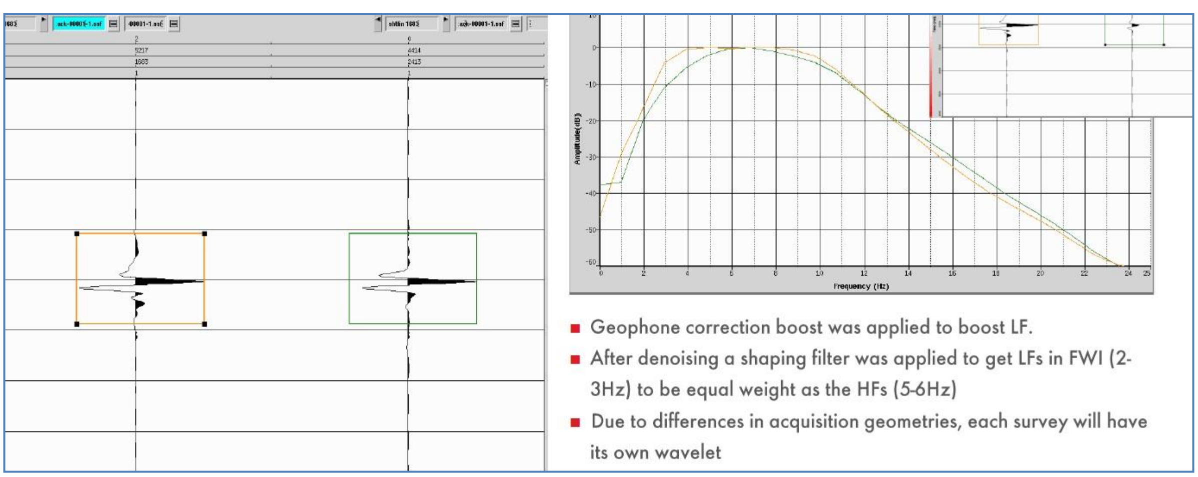

Figure 4: Wavelets for Survey A and Survey B

Sample shots were selected to test out optimum denoise parameters to derive diving waves for the inversion. The workflow for the denoising is captured in Figure 5 below with the outcome. Tests were carried out using someshots to optimize the FWI parameters, such as, on decimation, weighting, smoothing parameters, etc. Three (3) scales were executed, each with fifteen (15) iterations starting with a frequency range of 2.5-3-6-7Hz. Python script QC showed that with increasing scales the velocity convergence was improved. Test line migrations of selected iterations per scale also confirmed the velocity inversion worked. Migrated gathers showed improving flatness, albeit, with a scope for further flattening in TTI. The results were satisfactory and serves as a decent input into the sonic based velocity model that followed.

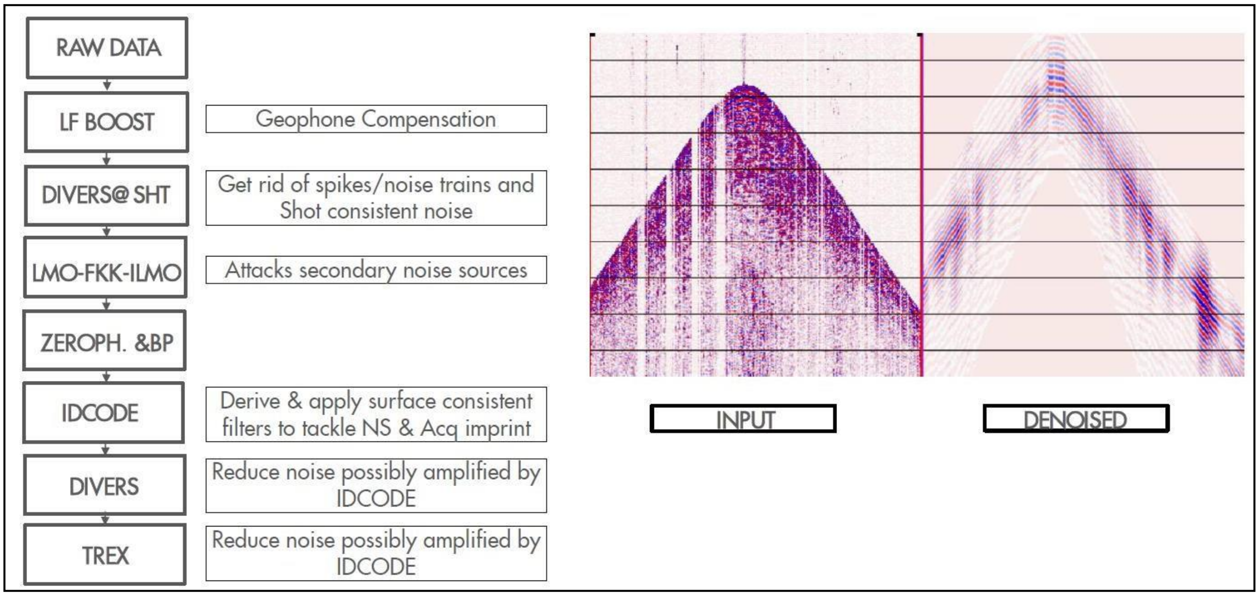

Figure 5: Pre-processing workflow applied with the results

FWI Result QCs

This is a very critical step in the FWI runs. The question is are we heading in the right direction? How are we converging as we move down the scales? The key driver is to reduce to the barest minimum the misfit between the observed and the modeled.

Generally, every geophysical inversion entails mapping for physical structure and subsurface properties of the Earth from measurements made at the surface of the earth (Russell, 1988).

In a broader sense, seismic inversion is the grand scheme of estimating elastic parameters directly from observed data (Yilmaz, 2001).

Seismic impedance inversion implies recovering of a broadband pseudo-acoustic impedance log from a band limited reflectivity seismic trace. I.e., creating an earth model of the earth using the seismic data as input (Russell, 1988).

Forward process: our seismic experiment is governed by the forward process. Earth

Model $\longrightarrow$ Modelling Algorithm $\longrightarrow$ Seismic Response

$$Gm = d \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots . \ 2.1$$

Where; d is a vector of ''data'' (or data residual); the seismic reflectivity trace

m is a vector of ''model'' consisting of the unknown earth parameters (Φ, AI, etc.), Earth reflectivity. G is

a geophysical operator which maps from the model space to the data space, e.g., wavelet.

Geophysical inversion means solving an inverse problem to find the spatially variable parameters, i.e., the ''model'' m, based on given geophysical measurements ''d''.

Inverse process:

Seismic Response ⟶ Inversion Algorithm ⟶ Earth Model

The fundamental equation governing seismic inversion for a linear system is given by.

$$m = G^{-1}d \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots ... \ 2.2$$

As can be observed in figure 6 below, convergence was achieved. The synthetic and the real seismic matchedbetter (more blue color) as we moved from the first iteration to higher iterations. Figures 7 and 8 shows the gather and the velocity (overlain on a stack) response owing to the FWI result.

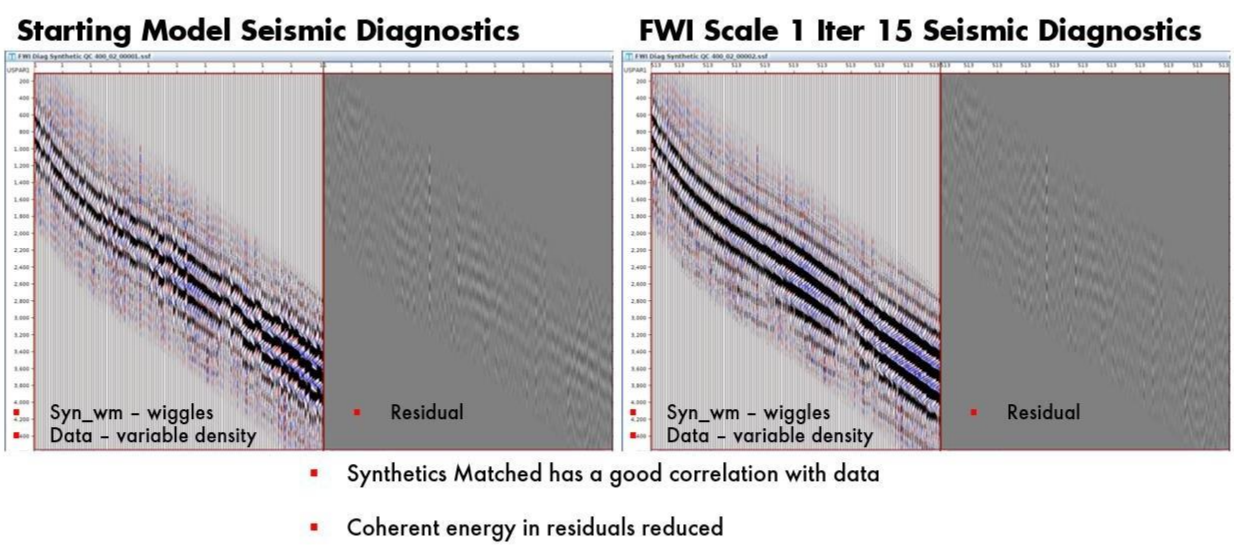

Figure 6: QC showing data and synthetics match plus residuals for starting model and scale 1 iteration 15

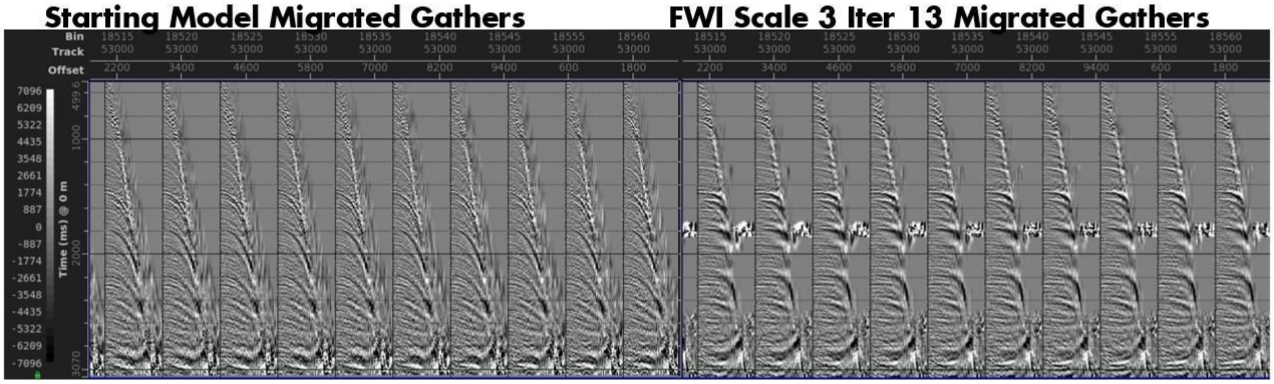

Figure 7: Migrated gathers showing improved quality of the velocity model after scale 3 iteration 13

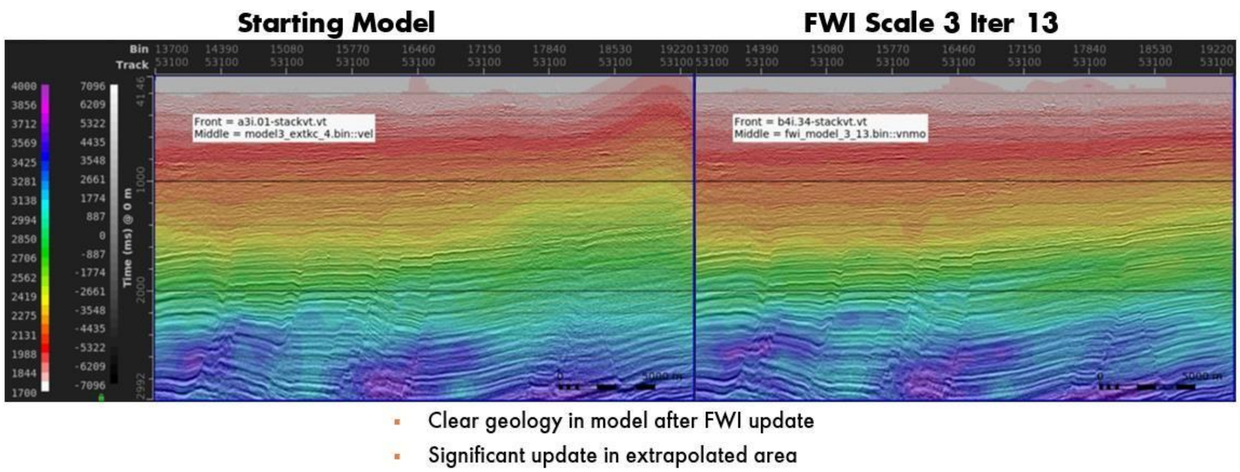

Figure 8: Inverted velocity model overlain on the seismic data Comparing the old PSDM model (top left) and the new PSDM model (top right) clearly shows the amount of detail that has been brought into the velocity model using the techniques described in this paper. The validation of the details is done by co-rendering the new PSDM model with the seismic (bottom). The variations in the velocity model are clearly consistentwith the fault blocks.

Well-Based Velocity Model Building

Some sonic logs representatives of the survey area were plotted together to identify events that are consistent which can be used as geological markers for the velocity model building. These events can be maximum flooding surfaces/sequence boundaries that are lateral extensive. Three events were identified from these, see figure 9 below.

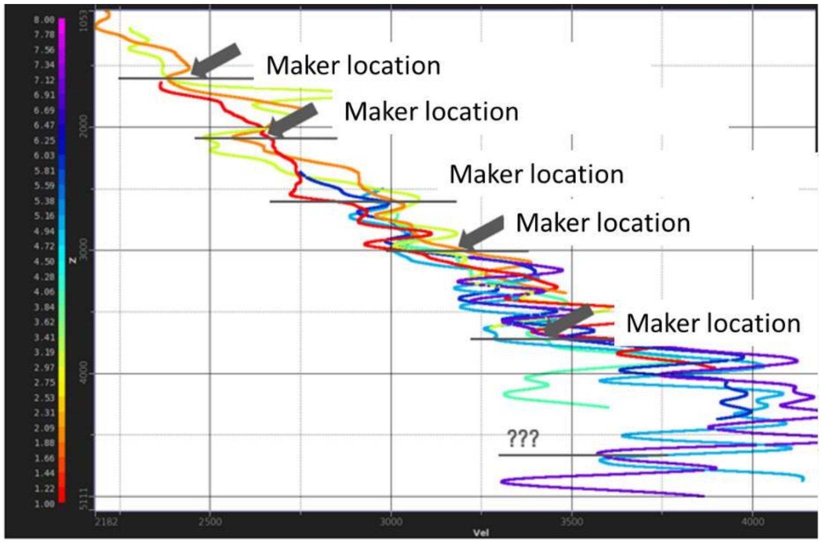

Figure 9: Plot of selected sonic logs in study area with proposed geological markers

Geological markers were identified QCed inputs – well markers, sonic logs, see figure 10. Twenty-four (24) sonic logs were QCed and associated well markers provided. Some of the well markers provided were cross-checked. Three (3) wells were used for well-to-seismic tie which aided the interpretation of the maker locations to cover the AOI. These were inputs into the Sonic Velocity Model engine.

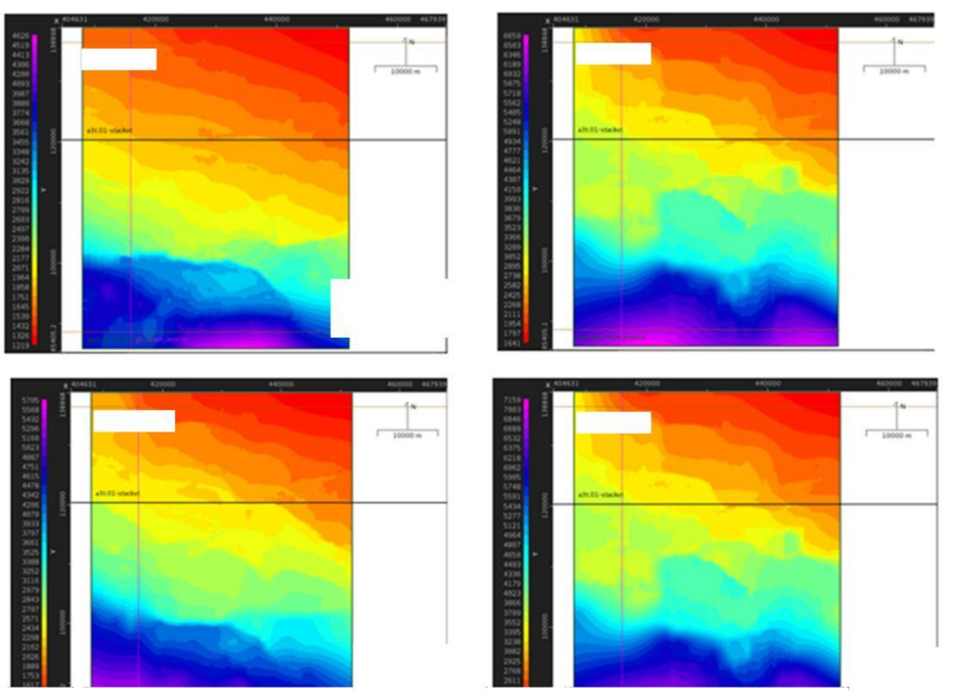

Figure 10: Interpreted events: Markers and model base

The Full waveform Inversion model together with the Sonic velocity were thereafter combined together and taken through a Travel Time Tomography (TTI). This resulted to a more detailed and geologically conforming velocity model as shown in figure 11 below.

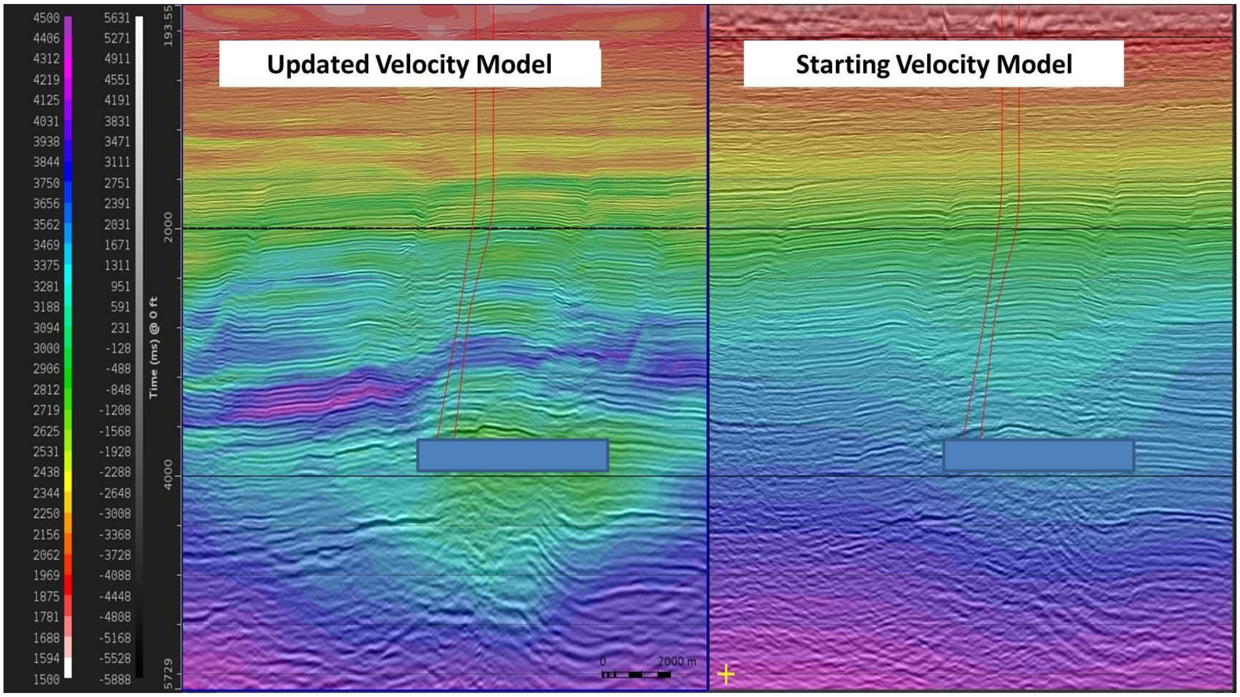

Figure 11: FWI + Sonic velocity model. The details from the velocity model are geologic and conforms to structural and stratigraphic changes.

Consequently, the robust velocity model; coming from FWI for shallow and Sonic model approach for the deepand a pass of travel time tomography (TTI), a Pre-stack Depth Migration (PSDM) and Reverse Time Migration(RTM) was done for seismic imaging.

RESULTS

Deploying FWI and incorporating geology from Sonic and TTI led to detailed velocity model with geologic features which gave rise to an improved imaging resulting in a better definition of structural and stratigraphic features within the field, see figure 11 below. This seismic aided the recent successful well drilling in the field. The biggest uncertainty in the area was structure, with this new RTM volume, the structures (faults) are better defined.

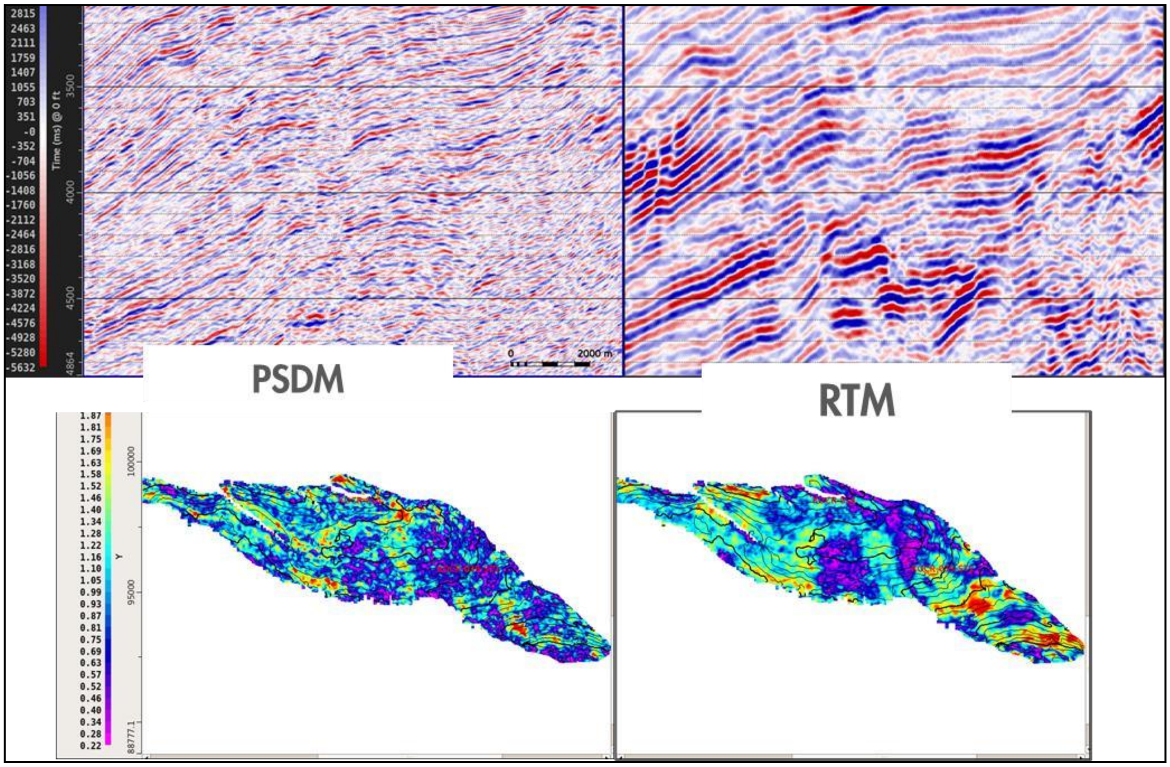

Figure 12: Comparing the old PSDM model (top left) and the new PSDM model (top right). Amplitude extraction of legacy (bottom left) and new seismic (bottom right)

As clearly shown the amount of detail that has been brought into the velocity model using the techniques described in this paper. The validation of the details is done by co-rendering the new PSDM model with the seismic (bottom). The variations in the velocity model are clearly consistent with the fault blocks.

Amplitude extraction showed better amplitude response conforming to structures. The amplitudes are less noisy and less patchy in the Reverse Time Migration (RTM) dataset compared to the conventional Pre-Stack depth migration (PSDM).

Well Correlation and Pre-Drill Analysis

The planned well targeted the deeper gas bearing reservoir and develop gas. The initial well plan and target location in the mid-deeper reservoir was based on an older vintage of seismic data.

The reservoir consists mainly of distributary channel deposits, divided into three sand members by two intra-reservoir shales correlatable across the reservoir. The major uncertainties include sand quality and development outside well penetration, and the thickness of the intra-reservoir shale layers, (see figure 12 below). Structure (depth to the reservoir at the planned well target location) is not considered a major uncertainty as the field iscovered by a robust velocity model coming from the Sonic T FWI (mentioned earlier) coupled with the proximityof existing wells to the planned well target location in the target reservoir. The new seismic dataset provided a clear image of the subsurface which aided well placement.

Figure 13: Stratigraphic correlation across the existing wells in the target reservoir showing the three sand members of the reservoir)

A high-resolution, high fidelity seismic data (RTM) was considered necessary for the accurate prediction of sand development (reservoir quality and thickness) for the reservoir in areas outside well control. A seismic re-processing exercise was therefore initiated to achieve this (The result from the RTM volume discussed earlier inthe paper). Post seismic processing, a relative inversion seismic cube was generated and utilized in the predictionof the range of reservoir properties expected at the target location in the reservoir of interest as shown in figure 14 below.

A relative impedance volume (90deg. Phase rotation) was also carried out on the seismic volume to further understand the structural complexities in the reservoir of interest. The reflectivity seismic volume shows the rock interfaces and has lesser resolution when compared to the relative acoustic impedance seismic volume (see figure 13 below). The inverted seismic volume provides a smooth image of the subsurface with information about therock layers and has better resolution.

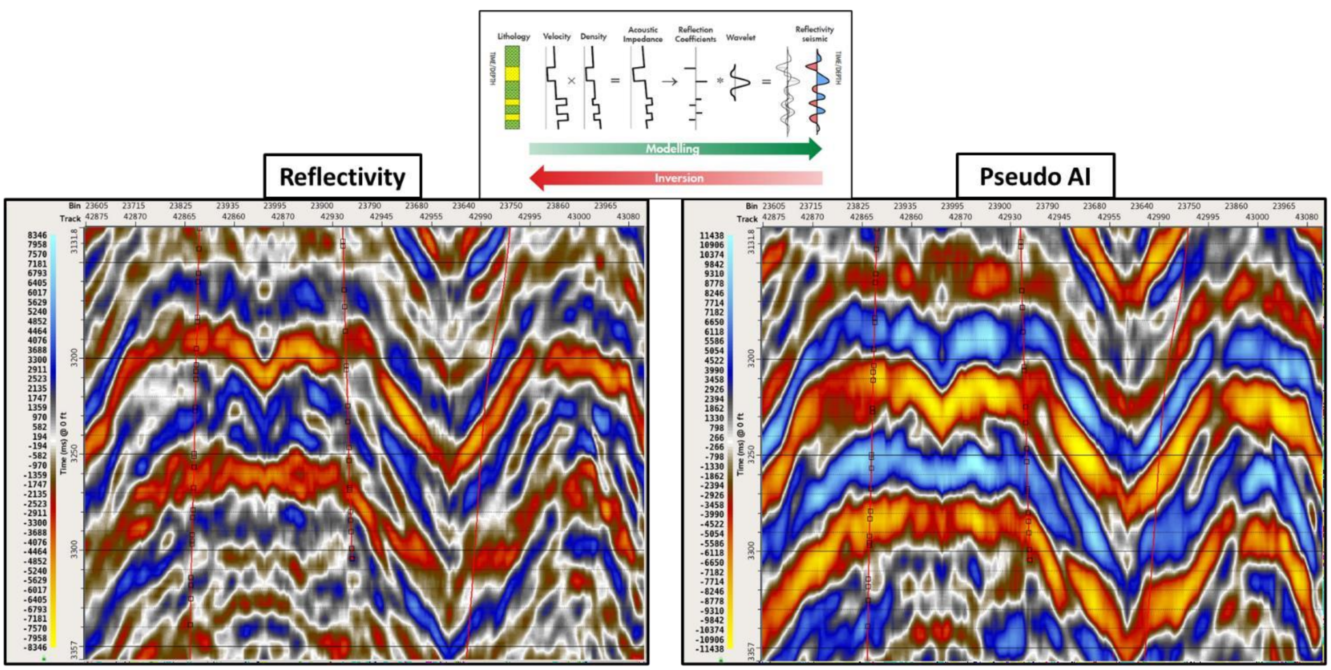

Figure 13: comparison of the reflectivity seismic volume and the relative acoustic impedance seismic volume: the reflectivity showed the rock interfaces while the relative AI showed the rock layers and are smoother.

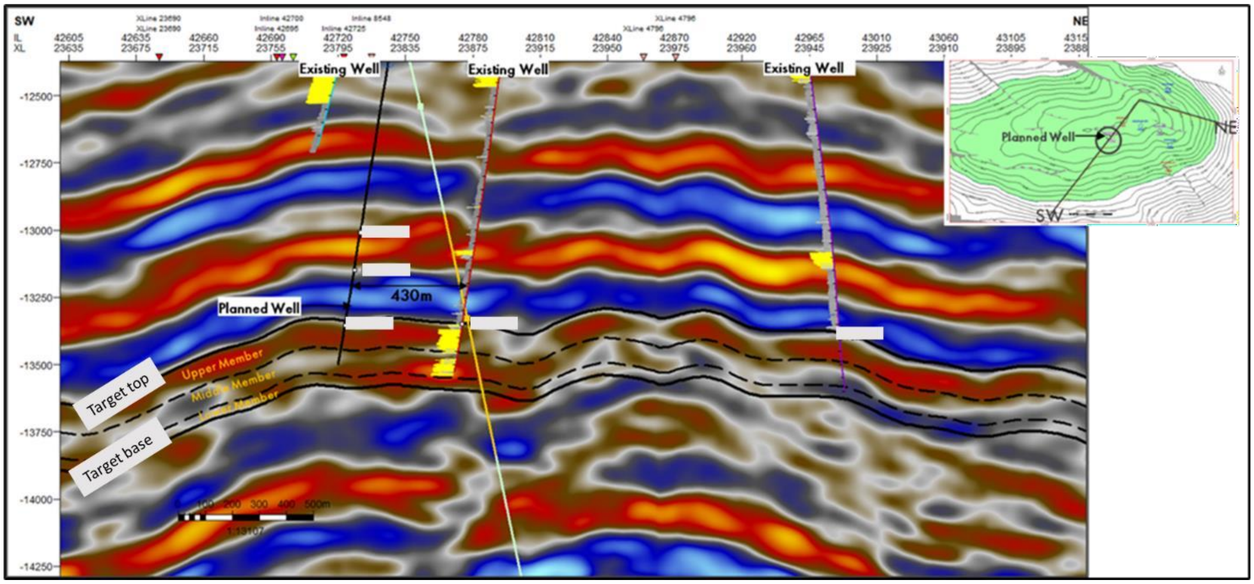

Figure 14: Relative Impedance Section Cross the planned well showing the expected stratigraphy of the F2000 reservoir along the planned well path.

Seismic amplitude pattern analysis from relative impedance. indicated a high chance of good quality reservoir sands, similar to the reservoir sand quality encountered in the offset wells in the field. Overall, a total thicknessof 125 ft (110 ft from the upper sand member and 15 ft from the middle sand member) was expected at the target location of the planned well.

Post-drill Analysis

Post drill analysis of sand thickness for the target reservoir validated the accuracy of reservoir sand quality prediction from the high resolution reprocessed seismic volume. The planned well encountered a total sand thickness of 133 ft TV (113 ft TV in the upper sand member) and a high net-to-gross of 0.86. Figure 14: Post drill seismic relative impedance section across the target reservoir. The thickness and reservoir property encountered is with pre-drill range of prediction.

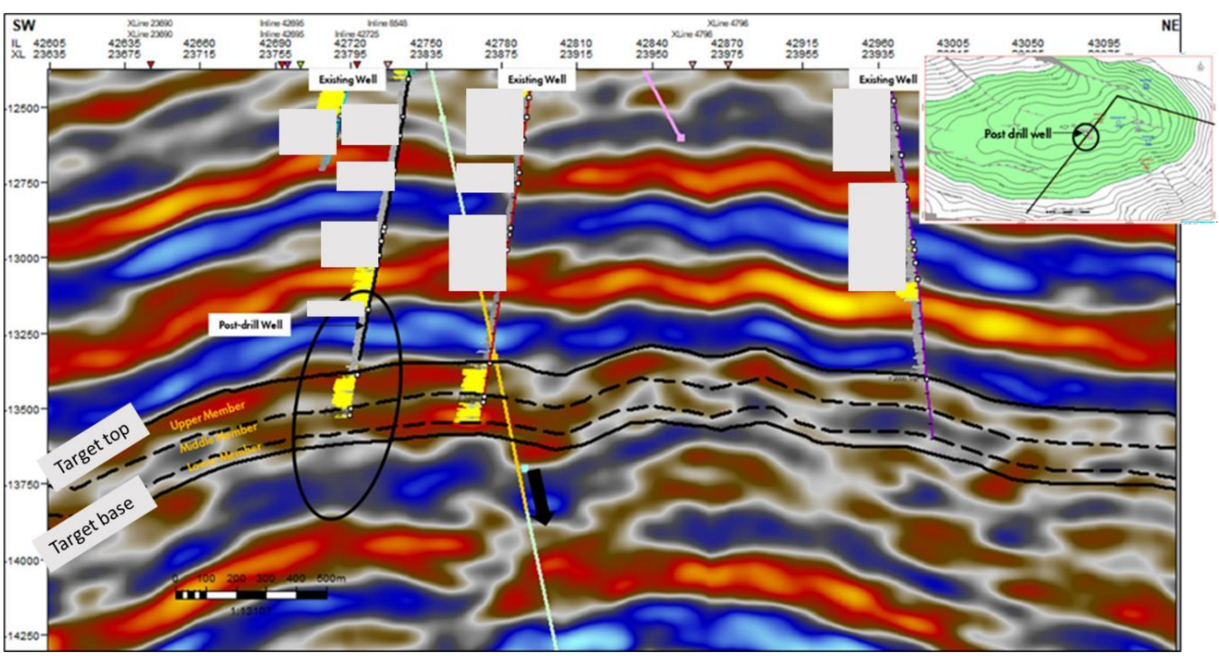

Figure 15: Post drill seismic relative impedance section across the target reservoir. Thickness and property prediction encountered is with pre- drill range of prediction.

CONCLUSIONS

To conclude, as can be observed, the new RTM volume provides better structural (faults) and stratigraphic definition especially in the deeper target areas of the field. Also, the amplitude extraction showed better amplitude response conforming to structures on the 'High-End-Imaging' (RTM) compared to the conventional imaging as highlighted. The amplitudes are less noisy and less patchy. Recommendation is to consider the best of both the 2021 PSDM and 2022 RTM in your evaluation and well planning.

Seismic amplitude analysis pattern from relative impedance. indicated a high chance of good quality reservoir sands, similar to the reservoir sand quality encountered in the offset wells in the field. Overall, a total thicknessof 125 ft (110 ft from the upper sand member and 15 ft from the middle sand member) was expected at the target location of the planned well.

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Owing to the success of the reprocessed seismic volume in the prediction of sand development across the target reservoir, this new seismic volume will be used to access the robustness of the well path, and to guide the placement of the planned wells in the reservoir.

ACKNOWLEDGEMENTS

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REFRENCES

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