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RESEARCH ARTICLE

DELINEATION OF SUBSURFACE STRUCTURES IN TOJA FIELD IN THE NIGER DELTA USING WELL-LOGS AND SEISMIC DATA

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ARTICLE DETAILS

ABSTRACT

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The subsurface structures delineation of TOJA Field southwest Niger Delta using well-log and seismic data is here presented. The reflectivity seismic amplitude and acoustic impedance, spectra decomposition volume derivatives were used for reservoir delineation. Seismic data and well logs have been integrated through seismic inversion as part of the techniques deployed in the delineation of subsurface structures in the Niger Delta basin. Well logs were tied to seismic data using four wells from four fields in the Niger Delta. Reflectivity seismic data was inverted to generate a 3D distribution of P-impedance in the fields of interest. Fluid and lithology sensitivity analysis including cross-plotting, forward seismic modelling and Gassmann fluid substitution was performed to delineate various subsurface structures. The TOJA prospect is a footwall-closure located behind the main bounding fault, north of the TOJA Field. The Field's structure is a fault-dependent footwall closure with a dip component in the shallow levels. The structure is bounded by three faults; a large east-west fault forms the boundary between the TOJA Field to the South and the TOJA North Field. This fault is relayed by a minor fault that delimits the south-western end of the accumulation. A northeast-southwest bounding fault separates the TOJA structure from the SATRA accumulations to the east and has a throw of between 200 and 400 ft. The results of this study can lead to a more cost-effective method for defining the Field Development Plan (FDP), through the use of seismically constrained reservoir information that would provide better well placement to achieve improved production.

KEYWORDS

Reservoir, subsurface structures, porosity, well-logs, seismic, inversion, Niger Delta, Nigeria

1. INTRODUCTION

The Niger Delta is a very prolific hydrocarbon province within the West African subcontinent. Exploration activities have been concentrated in the onshore part of this basin, but as the delta becomes better understood, exploration influences are gradually being shifted to the offshore. Although the geology, tectonics and evolution of the Niger Delta are fairly well known, new ideas by the use of recent technologies are expected to increase as new analytical tools and concepts evolve. This work is an integrated structural, seismic, and well log study conducted in the TOJA Field, onshore Eastern Niger Delta, and targeted at improving the present understanding of the structural out lay, reservoir extent, quality and potential within the TOJA Field.

The aim of this research is to delineate subsurface structures in the TOJA Field of the Niger Delta using well-logs and seismic data. This study would help in the characterization of subsurface structures, fault zones and physical properties of the formations through integration of geophysical and geological measurements. It will further provide better understanding of the subsurface leading to a better identification of optimum well placement position guide for economically viable well drilling activities. Delineation of subsurface structures, reservoir quality and lateral extents are of key importance in the determination of economic viability of Fields and exploration opportunities [1-5]. With limited well data control and difficulty in the resolution of some

embedded events in the seismic data, this study seeks to proffer ways of reducing uncertainties in the identification and classification of some subsurface structures by the integration of seismic and well log data.

Figure 1: Map of the Niger Delta showing the area of study

2. STUDY AREA AND ITS GEOLOGY

The TOJA Field is located about 40 km southeast of Port Harcourt within the swamp area in the Niger Delta, Nigeria Fig. 1). The origin of the Niger

Delta basin is related to the continued subsidence of the southern Benue Trough as defined by the Chain and Charcot Fracture Zones. Thus, the Cenozoic Niger Delta Basin is superposed on the southern Benue and the Anambra Basins [6,7]. The stratigraphic components of the Niger Delta comprise subsurface and outcropping units. The outcropping units are present in the northern parts of the delta. They continue in the surface as the subsurface equivalents, only getting younger basinward. In fact, all the facies are still being deposited in the present day Niger Delta as continental, transitional (paralic) and marine sediments. Each of the stratigraphic units named in is characterised by a set of sedimentological features including lithology, textures, composition and sedimentary structures, the study of which would enable the determination of the depositional environments. The Imo Shales constitute an extensive unit of predominantly green grey shales and siltstones with minor limestone beds and some sandstone units. The shales were deposited in a shallow marine setting.

The Ameki Group overlies the Imo Shales and outcrops over a large area of southern Nigeria. In the southeastern parts, especially north of Umuahia, it consists of highly fossiliferous calcareous siltstones indicating deposition in a shallow marine environment. In the areas within Anambra and Imo States, the unit consists of loose sands deposited as subtidal sand waves. Being loose and unconsolidated, it is highly erodible. This is why the area it underlies is being intensely affected by sheet and gully erosion. Farther westwards around Onitsha and Asaba to Okpanam, the unit consists of highly ferruginous, coarse, pebbly and relatively consolidated sandstones which are thought to have been deposited in a continental, probably fluvial setting.

Overlying the Ameki Group is a lignite-bearing set of beds called the

Ogwashe-Asaba Formation. The lignite beds consist of brown coals a few centimetres to 2m thick exposed in a belt that stretches from Asaba area south- eastwards to north of Calabar. The unit is a depositional product of swamp forests. The Benin Formation predominantly sand, with rare mudrock beds, Fig. 2. Conglomerates and pebbly horizons are common. It is up to 3000 m thick, as noted in some oil wells. In the Obeakpu-Afam-Yorla areas of the Niger Delta, the formation has a clay unit over 550 m thick (Afam Clay Member). Lignitic horizons are also common in the formation, suggesting continental depositional environments that included both fluvial and swampy (palludal) settings.

The subsurface units of the Niger Delta are the Akata and the Agbada Formations (Benin Formation being regarded as both surface and subsurface in mode of occurrence), Fig. 2. The Akata Formation is considered the subsurface stratigraphic equivalent of the Imo Shales. It consists predominantly of shales and subordinately of sands thought to be mostly of turbiditic origin. The unit contains abundant depositional water, i.e. the shales had not been fully dewatered after deposition and are said to be under compacted. This accounts for the shale bulge phenomenon by which shale ridges have been formed, facilitating the structuration of the overlying Agbada into depobelts. It was deposited in a fully marine setting and was actually the prodelta for the overlying paralic unit. Its equivalent is still being deposited in the present-day in the far offshore.

The Agbada Formation (Fig. 2), sandwiched between the Akata Formation below and the Benin Formation above, is the hydrocarbon-bearing unit of the Niger Delta. It consists of alternating sands and mudrocks, deposited in a variety of wave-dominated and tide-influenced environments, including estuarine, beach, and shallow marine.

Figure 2: The map of cross-section of Niger Delta showing the stratigraphic columns of the subsurface units

3. MATERIALS AND METHODS

3.1 Seismic acquisition and interpretation

The TOJA 3D survey seismic volume was loaded onto the various interpretation platforms. Seismic quality is generally good but deteriorates at deeper levels (below 3500ms). Localized masking from calcite cementation of sands above X10000 level further reduces the seismic quality. This occurs above the crest of the TOJA structure, and along the main bounding fault in the TOJA North area. The structural data quality was further enhanced by the application of further structural highlighting and denoising techniques over the dataset.

Seismic events in the vicinity of the TOJA North Field are generally well resolved, continuous and can be readily mapped down to 3 seconds Two Way Time. Key horizons were correlated from the TOJA-North Field and from nearby wells TOJANorth-001, TOJA-North-002, TOJA-21, BOCH-001, and SATRA-1. A number of major faults, some with throw in excess of 1000 ft, cross the area of interpretation and impede ability to directly correlate events between wells in adjacent fault blocks. Despite this, the coverage of the 3D seismic coupled with good seismic character match across faults generally supported confident, unambiguous correlation of events into the TOJA study area and other adjoining blocks.

3.2 Well-logs Data

Synthetic seismograms were used to compare seismic reflection data to well log data. A comparison of the reflectivity or acoustic impedance responses derived from seismic and from wireline logs enabled matching of seismic events with geological markers. The objective of this comparison was to identify seismic reflectors as geological units and/or to calibrate seismic amplitudes [8-14]. A total of 28 seismic-to-well matches were generated and significant improvements in match quality were achieved. Better validation and editing of sonic and density logs. Some of the well-logs are shown in Figure 3.

3.2.1 Log calibration

Calibration started with picking checkshot times. The checkshot times seems to favour trough-to-trough picking of VSP times (15-19). For this study, calibrated sonic and density logs and checkshot data (time/depth calibration) were used. When unconditioned, the logs used (Fig. 4) to generate well-to-seismic ties, the overall correlation achieved 63%, while when conditioned (Fig. 5), the overall correlation significantly improved to 88%. As a result of performing good well data conditioning, acoustic and petrophysical information for reservoir modelling was derived and definition of geological boundaries and hydrocarbon contacts on the

seismic data was achieved as well as highlighting some subtle subsurface structures.

Well TOJA North-1

Well TOJA North-2

Well TOJA-21

Well SATRA-1

Well Boch-28

Figure 3: Panel showing well log data (Compressional Velocity, Density, Gamma Ray, Impedance, Calliper and Resistivity)

Figure 4: Well-to-seismic tie using unconditioned/conditioned/uncalibrated logs give a lower correlation of 63%.

Figure 5: Well-to-seismic tie using calibrated logs give a higher correlation of 88%.

3.3 Constructing the Synthetic Seismogram

The construction and correlation of the data with the primary reflectivity usually produces a satisfactory well tie. A wavelet was estimated to be convolved with the reflection series. A problem in estimating the wavelet was that the transmission response of the earth has to be included if the filtered synthetic seismogram is to match the seismic data. A matching process was therefore required. In generating a fit for purpose wavelet, it was ensured that the quality of the seismic data has an impact on our confidence in well ties and wavelet extractions. Wavelets were extracted along the boreholes for individual wells to generate synthetic seismograms and subsequently overlay on the seismic data to obtain the reflectors corresponding to the available check-shots for geological marker and petrophysical log data conversion from depths to time on the seismic data.

The correlation Window (Figure 6) contains several panels which were predefined in the cross-correlation tab. Tmin correlates to the Centre time for first cross correlation while Tmax is the centre time for the last cross correlation. The panels are as follows: Input seismic (Blue); Well synthetics (Orange) and filtered synthetics (Red); Hanning taper weight function for seismic (Yellow); Cross correlation filter (Green), and Cross correlation trace.

Figure 6: Cross correlation window derived through the process of synthetics generation.

3.4 Creating a reflection series in time

Velocities and densities were used to derive the bulk and shear moduli, which were then averaged using the harmonic average. Velocities are re-constituted from the averaged moduli and the arithmetically averaged density log. The generated synthetic seismograms show that the tops of events suggest distinct peaks for proper horizon loop identification on the seismic data (Figs. 7 – 11). The synthetics were generated by extracting a wavelet along the well borehole and using this wavelet to convolve the reflectivity series created by the sonic and density curves of the well. The ensuing synthetic was overlain on the seismic section and matched with a trace at the well location to ensure consistency. Overall stable, zero phase wavelets (inset bottom of Fig. 12) were extracted at the well locations and used in the synthetic seismogram generation.

The review of the generated synthetics and its comparison with the seismic suggests that positive amplitudes as displayed in seismic sections are soft kicks and displayed in the sections as blue. As a result of the good matches, proper identification of events on seismic data was achieved.

Figure 7: Well-to-Seismic tie for TOJA North-001 well. The blue wiggles are the seismic data while the red wiggles are the synthetic seismogram.

Figure 8: Well-to-Seismic tie for TOJA North -002 well. The blue wiggles are the seismic data while the red wiggles are the synthetic seismogram

Figure 9: Well-to-seismic tie for SATRA-001 well. The blue wiggles are the seismic data while the red wiggles are the synthetic seismogram.

Figure 10: Well-to-seismic tie for SATRA-001 well. The blue wiggles are the seismic data while the red wiggles are the synthetic seismogram.

Figure 11: Well-to-seismic tie for TOJA- 021 well. The blue wiggles are the seismic data while the red wiggles are the synthetic seismogram.

Figure 12: The generated input wavelet for SATRA-001 well-to-seismic tie.

3.5 Seismic and Constrained Sparse Spike Inversions

Seismic inversion was carried out on the TOJA seismic data to generate 2D acoustic impedance volume. This was calibrated to well data in order to understand strengths and limitations of the generated layer properties for quantitative analysis. It was also used to improve geological interpretation, map porosity distribution, optimize well locations, and to reduce drilling risks.

4. RESULTS AND DISCUSSION

Sixteen full-stack seismic lines with a total length of 65.4 km containing 6200 traces were inverted and calibrated to 4 wells (TOJA NORTH-1, TOJA NORTH-2, BOCH-1, and SATRA-28). Seven wells were conditioned before inversion was executed. TOJA-21 and TOJA-24 were used as blind wells to validate the inversion results. Well TOJA-21 was a dry well in the primary reservoir interval. To build the low frequency model, the original geological interpretation was used in the first pass inversion and was then updated to generate final inversion results.

A constrained sparse spike inversion (CSSI) was run by integrating the information from well data, seismic data, and geological interpretation. CSSI is a method that integrates full stack seismic data, geological interpretation, and well log data to generate acoustic impedance with higher resolution than the input seismic data. The process works by removing the wavelet from the seismic data, converting seismic interface property into layer property, and by integrating a low frequency model [20,21]. Acoustic impedance is a property of the rock layer itself, unlike reflectivity, which is a property of the interface between two acoustic layers. It is used in carrying out more accurate and detailed structural and stratigraphic interpretations than can be obtained from seismic (or seismic attribute) interpretation. In many geological environments acoustic impedance has a strong relationship to petrophysical properties such as porosity, lithology, and fluid saturation.

4.1 Spectral Decomposition

Spectral decomposition requires the transformation of each individual 1D seismic trace, $s(t)$ into a 2D time-frequency representation, $s(\tau, f)$. Many methods exist to achieve this and each has different resolution capabilities in time and frequency. The relative thickness of stratigraphic units of Regional (TOJA, TOJA-North, BOCH and SATRA Fields) Interpretation of the X1000 reservoir was observed using spectral decomposition see Fig. 13. As strata become thicker, the peak frequency of their seismic response tends to be lower, and vice versa. By taking a horizon slice of a 3D seismic volume, this study was able to identify the thickening directions by viewing the slice at progressively lower frequencies.

The transformed amplitude data was used to delineate the reservoir extent and highlight the differentiated sand body (erosional surface possibly containing a different depositional material from that of the Hydrocarbon bearing sands). This was observed to have cut through the reservoir as also seen by the Impedance volume and amplitude map.

Figure 13: A slice section of the spectrally decomposed reflectivity seismic data through the X1000 reservoir at a frequency of 8Hz.

4.2 Acoustic-impedance Inversion using Constrained Sparse Spike Inversion

4.2.1 Impedance Model

To create an Earth Model, the first step in model building is to design the structure. This is done by providing two pieces of information - the interpreted horizons and the model "framework". The framework, in the form of a spreadsheet, describes the ordering of the horizons in space and time and their behaviour at faults. The horizons, which can include interpreted faults, provide structure information. Together, these form a blueprint for the model. The model is completed by populating it with geophysical information, usually input in the form of well log data [22]. The well log data provides the low frequency component of the impedance since this is needed to complete portion of the seismic inversion. The logs are usually provided in depth and the horizons in time. Thus, it is necessary to create a time-depth transformation if these two pieces of information are to be rationalized. Input sonic logs are integrated, hung on an input time datum (one of the input horizons) and drift-corrected to tie the time horizons. Upon completion, the model exists in both time and depth and time-to-depth and depth to-time transformations are possible. Interpolation of the input log information between wells is done along layers, respecting both stratigraphy and faults. Interpolated data from each horizon-defined interval define the constraints in CSSI and the inversion trend model. The impedance model may be used to construct low-frequency information that cannot be reliably estimated from seismic data.

4.2.2 Wavelets Estimation

Wavelets are estimated, preferably using well control. All modern seismic inversion methods require seismic data and a wavelet estimated from the data. Typically, a reflection coefficient series from a well within the boundaries of the seismic survey is used to estimate the wavelet phase and frequency Fig. 14. Accurate wavelet estimation is critical to the success of any seismic inversion. The inferred shape of the seismic wavelet may strongly influence the seismic inversion results and, thus, subsequent assessments of the reservoir quality.

Wavelet amplitude and phase spectra are estimated statistically from either the seismic data alone or from a combination of seismic data and well control using wells with available sonic and density curves. After the seismic wavelet is estimated, it is used to estimate seismic reflection coefficients in the seismic inversion using suitable estimation algorithms which removes the wavelet effect.

The wavelet alignment is good boosting confidence on the Impedance volume. When the estimated (constant) phase of the statistical wavelet is consistent with the final result, the wavelet estimation converges more quickly than when starting with a zero-phase assumption. Minor edits and "stretch and squeeze" may be applied to the well to better align the events. Accurate wavelet estimation requires the accurate tie of the impedance log to the seismic. Errors in well tie can result in phase or frequency artifacts in the wavelet estimation. Once the wavelet is identified, seismic inversion computes a synthetic log for every seismic trace. To ensure quality, the inversion result is convolved with the wavelet to produce synthetic seismic traces which are compared to the original seismic. It was also important to ensure that the wavelet matches the phase and frequency of seismic data.

4.2.3 Constraints

Inversion is carried out with constraints around the trend model. Compressional sonic from the wells were used to generate the well log impedance which introduced constraints across the Fields, honouring these well inputs. The well log impedance is quality checked and compared with the seismically generated Pseudo P-Impedance see Fig. 15.

Figure 14: Wavelets from TOJA-North-002, BOCH-028 and SATRA-1 were input into the acoustic impedance generation.

Figure 15: Good agreement between the well-log impedance (in blue) and pseudo-extracted P-impedance (in pink) authenticating the seismically generated acoustic impedance volume.

4.2.4 Low Frequency Model

The low-frequency component of the geologic-impedance is merged with the high frequency component contributed from the seismic data Fig. 16. For the TOJA Field geologic model, the framework is composed of the horizons from the seismic-based structural interpretation, plus density and velocity information from four wells. Horizons are interpolated and the layers in the model are populated with interpolated log values consistent with the stratigraphy of each layer. Faults and truncations are honoured.

Wavelet estimates were made at wells TOJA-North-002, BOCH-001 and SATRA-028 as their individual wavelets are stable and have good phase alignment. Selection of the optimum wavelet and its scaling was critically considered. The above stated wavelets gave the best overall performance and were selected along with the match to the seismic Fig. 17.

Figure 16: A graphical representation of low frequency and high frequencies components of the acoustic impedance volume.

Figure 17: Well tie for seismic inversion done on SATRA-001 well

The CSSI inversion used constraints around the trend model. Synthetic seismic data were compared to the real seismic to identify any problems. For the CSSI, the correlation was greater than 96-97% in the area of interest, indicating a very good seismic match. Well log impedance results were merged with the geologic-impedance model. Fig. 18 is the final impedance result across the TOJA-North Field.

In Figure 19, a cross-section through the final impedance model, the fit between the well log and inverted acoustic impedance is quite good in the TOJA, TOJA North, BOCH and SATRA Fields. The results of the inversion were acoustic impedance and porosity derived from the simple relationship between porosity and acoustic impedance as observed from the well data. The results were used to interpret the facies distribution, channelized structures and to delineate lateral extent of the X1000 reservoir sands (Figs. 20-22). By adding careful hydrocarbon distribution interpretation, the inversion results have been used for locating new wells positions to drill hydrocarbon.

The acoustic impedance volume from our constrained sparse spike inversion (CSSI) clearly shows the lateral extent of the X1000 reservoir and the incised clay channel fill. The CSSI result has been used to refine the interpretation of the X1000 time horizon and to more confidently delineate the channel edges.

Figure 18: A cross-section through the final impedance showing the TOJA, TOJA North, BOCH and SATRA Fields.

Figure 19: Generated impedance overlain with well log impedance

Figure 20: A section of the generated impedance showing the digitisation and channel feature in X1000 reservoir through TOJA-North.

Figure 21: Flattened X1000 horizon showing channel incision.

Figure 22: Reservoir lateral extent delineated by applying reservoir specific acoustic properties.

Figure 23: Stratigraphic slice from a horizon porosity volume, showing very high porosity around an existing well.

4.2.5 Porosity

The porosity derived from the generated acoustic impedance volume was validated by firstly extracting a slice from around the already producing TOJA Field. Very high porosity (Fig. 23) seen on the slice was compared to that encountered by a well and there was a good agreement; and

further validation was done by cross plotting the impedance volume against the derived porosity Fig. 24. The cross-plotting technique is often useful in the differentiation of lithology types in fluid discrimination scenarios [23-25].

4.2.6 Blind Well Test

A blind well test is an important tool to investigate whether the inversion result is valid not only at well locations, but also at different places. To do this, the inversion was carried out by not including all wells but only some of them. After inversion, the P-impedance of the blind well was overlain on top of the inverted P-impedance section to compare. Fig. 25 shows a blind well (BOCH-01) example. The generated impedance data is overlain by Gamma Ray log which discriminates between the sands and shales hence authenticating the generated impedance volume.

Figure 24: Porosity of hydrocarbon and brine-bearing sand well differentiated

Figure 25: Blind well log (Gamma Ray) overlain on impedance data show a good match with the sand bodies.

4.2.7 Amplitude extraction and analysis

Amplitude extractions were carried out in TOJA Field and the adjacent TOJA-North Field, a Field already producing. In TOJA-North Field, the X1000 reservoir was used as calibration. The extracted amplitude map showed an amplitude anomaly, which is consistent and conformable to structure see Fig. 26. A polygon was extracted and the seismic amplitude cross plotted.

The amplitude over the TOJA Field at the X1000 level shows consistent and structurally conformable amplitude that is gas related. Hydrocarbon contact at this level, which is seen at 1604ms, is easily read off from the

seismic, amplitude map and cross plot.

The time interpretation was extended to the TOJA-North area, and the amplitude maps showed an anomaly similar to that of TOJA over the crest of the structure (see Fig. 27). The amplitude-time cross-plot of selected polygon reveals a good tuning curve and amplitude build up starting at about 1466ms.

For the TOJA-North prospect, conformable amplitude anomaly is seen but this amplitude is truncated at the northern part of this reservoir by an erosional sand body with different reservoir property.

Figure 26: Hydrocarbon contact seen by the Seismic at 1604ms agrees with that seen by the time Amplitude-time crossplot for the X1000 horizon for TOJA Field.

Figure 27: Hydrocarbon contact seen by seismic at 1446ms agrees with that seen by the amplitude-time cross-plot for the X1000 horizon for TOJA-North Field.

5. CONCLUSION

Reservoir delineation, quality and lateral extent are of key importance in the determination of economic viability of any Fields and exploration opportunities. With limited well data control, the lateral uncertainty in reservoir properties such as N/G, porosity and reservoir continuity, can be further reduced with the use of 3D seismic data. This project discusses the reliability of the use of well log and seismic data and its attributes in the delineation of subsurface reservoirs. In addition, it discusses the use of seismic inversion results to aid in distinguishing different lithologies (hydrocarbon sands versus brine sands/shales), and in assisting in the stratigraphic interpretation of a reservoir in the Niger Delta.

The seismic amplitude and other volume derivatives (acoustic impedance, spectra decomposition, etc.) have been used for reservoir delineation. The integration of the 3D seismic is not without its own limitations. The key factors to be considered are data quality and other influences of the seismic amplitude response with respect to hydrocarbon content, such as tuning effect, porosity variation, and saturation changes. The result of this study has led to a more cost-effective method for defining the Field Development Plan (FDP), through the use of seismically constrained reservoir information that provides better well placement to achieve improved production. The use of quantitative seismic methods was used to identify and characterize hydrocarbon reservoirs from seismic amplitude data and well logs. Seismic data and well logs have been integrated through seismic inversion to delineate subsurface structures in the Niger Delta basin. Well logs were tied to seismic data using four wells from four Fields in the Niger Delta. Seismic data was inverted to generate a 3D distribution of P-impedance in the Fields of interest. Fluid and lithology sensitivity analysis including cross-plotting, forward seismic modelling and Gassmann fluid substitution was performed to delineate various subsurface structures.

From the well log data, useful information on the following has been derived: Hydrocarbon Sands discrimination; Events identification. Secondly, the use of the seismic data as seen from this study yielded some positive business impact in the following areas: Better understanding of reservoir extent/lateral continuity; more accurate hydrocarbon contact information; Highlighting of channels; subtle faults identification; and better well placement and reduced missed opportunities.

This study has successfully delineated the TOJA/TOJA-North X1000 reservoir lateral extent. The X1000 reservoir is eroded on the northern part by a different sand facie. The hydrocarbon (HC) contact as predicted from the amplitude studies at the X1000 reservoir is at 1466ms in the TOJA-North Field.

Reflectivity Seismic Data from Sato field served as an input for both the Acoustic Impedance generation and geohazard analysis. Well log cross plots for SATO-01 and SATO-03 show significant overlap between the sand and shale properties in the P-Impedance space for X1000, X3000 and X5000 reservoirs. A slight separation in shale and sand acoustic properties exist for X1000, X3000 and X5000 reservoirs for SATO-01 and SATO-03 respectively. Acoustic Impedance attribute extraction shows less contrast between sand and shale. However, red areas on the map is indicative of areas with better quality sands. Bluish areas could also be indicative of sands which are of relatively harder acoustic properties.

The Sato planned wells are likely to encounter some good sands at X1000 and X5000 reservoirs levels. At the X3000 reservoir, the sands are most likely to be of relatively harder acoustic properties. Geohazard assessment was carried out for the four planned Sato wells (SATO-CSBT-01, SATO-CSBT-02, SATO-KSBK-03 and Sato- KSBK-04). Amplitude and semblance analysis based on seismic data did not indicate any geohazard issues around the planned wells surface locations and top-hole sections.

Observations from the offset well analysis indicate issues with wellbore stability ranging from tight holes/spots, stuck pipe and hole pack off below 5000 ftss. Intervals between surface and 5000ftss are free of any geohazard.

Based on SATO Field sand development modelling, acoustic impedance volume analysis and geohazard assessment, the planned well trajectories have been better designed to generally traverse safely through the target reservoirs and landing in good sands. The benefits of bringing in the historical information from the previously drilled wells provided an added level of safety assurance for successful drilling of the new wells and hopefully minimize the possible chance of occurrence of unanticipated surprises.

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