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VOLUMETRIC CALCULATION IN TIGHT SAND RESERVOIR BASED ON INTEGRATION INVERSION PRE-STACK AND STATIC MODELING

PERHITUNGAN VOLUMETRIK PADA RESERVOIR PASIR KETAT BERDASARKAN INTEGRASI INVERSI PRA-TUMPUKAN DAN PEMODELAN STATIS

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Abstract. This study investigates the volumetric calculation of hydrocarbon reserves in tight sandstone reservoirs by integrating pre-stack seismic inversion and static modeling. The research focuses on the Penobscot Field in the Scotian Basin, Nova Scotia, Canada, specifically the Middle Mississauga Formation, which contains tight sandstone. The study aims to estimate hydrocarbon reserves in tight sandstone, which has distinct characteristics compared to typical sandstone. The static modeling approach integrates seismic and well data to construct a structural model, allowing the spatial estimation of volume shale (V_{shale}), effective porosity (ϕ_e), water *saturation* (S_W), and net to gross (NTG). Pre-stack seismic inversion is applied to generate detailed subsurface models, utilizing seismic data before the stacking process for more comprehensive information. By using data from various angles of incidence, this method improves resolution and enhances the ability to detect complex subsurface layers, producing a model with physical rock parameters like density and P-wave velocity. The study uses pre-stack seismic inversion to obtain an acoustic impedance profile, which is then applied in facies and petrophysical property simulation using geostatistical methods SGS and SIS to align simulation trends with inversion results. This integration is expected to produce a reliable model for hydrocarbon reserve volume calculation. Results indicate that the tight sandstone zones contain hydrocarbon reserves, primarily gas, due to the low porosity of the sandstone and the lower viscosity of gas compared to oil, enabling gas to move more easily into narrow pores. The simulated effective porosity (ϕ_e), ranges from 0.01 to 0.18, volume shale (V_{shale}) from 0.01 to 1, water saturation (S_W) from 0.64 to 1, and net to gross (NTG) values from 0.7 to 1.00, resulting in a GIIP volume of 4494 sm^3. These findings demonstrate that integrating these methods effectively calculates hydrocarbon reserves in tight sandstone.

Abstrak. *Studi ini menyelidiki perhitungan volumetrik cadangan hidrokarbon di reservoir batupasir ketat dengan mengintegrasikan inversi seismik pra-tumpukan dan pemodelan statis. Penelitian ini berfokus pada Lapangan Penobscot di Cekungan Scotian, Nova Scotia, Kanada, khususnya Formasi Middle Mississauga, yang mengandung batupasir ketat. Studi ini bertujuan untuk memperkirakan cadangan hidrokarbon di batupasir ketat, yang memiliki karakteristik berbeda dibandingkan dengan batupasir tipikal. Pendekatan pemodelan statis mengintegrasikan data seismik dan sumur untuk membangun model struktural, memungkinkan estimasi spasial volume serpihan (V_{shale}), porositas efektif (ϕ_e), saturasi air (S_W), dan rasio bersih terhadap kotor (NTG). Inversi seismik pra-tumpukan diterapkan untuk menghasilkan model bawah permukaan yang detail, memanfaatkan data seismik sebelum proses penumpukan untuk informasi yang lebih komprehensif. Dengan menggunakan data dari berbagai sudut datang, metode ini meningkatkan resolusi dan meningkatkan kemampuan untuk mendeteksi lapisan bawah permukaan yang kompleks, menghasilkan model dengan parameter batuan fisik seperti densitas dan kecepatan gelombang P. Studi ini menggunakan inversi seismik pra-tumpukan untuk memperoleh profil impedansi akustik, yang kemudian diterapkan dalam simulasi fasies dan sifat petrofisik menggunakan metode geostatistik SGS dan SIS untuk menyelaraskan tren simulasi dengan hasil inversi. Integrasi ini diharapkan menghasilkan model yang andal untuk perhitungan volume cadangan hidrokarbon. Hasil menunjukkan bahwa zona batupasir ketat mengandung cadangan hidrokarbon, terutama gas, karena porositas batupasir yang rendah dan viskositas gas yang lebih rendah dibandingkan dengan minyak, sehingga gas dapat bergerak lebih mudah ke dalam pori-pori yang sempit. Porositas efektif yang disimulasikan (ϕ_e) berkisar dari 0,01 hingga 0,18, volume serpih (V_{shale}) dari 0,01 hingga 1, saturasi air (S_W) dari 0,64 hingga 1, dan nilai net to gross (NTG) dari 0,7 hingga 1,00, menghasilkan volume GIIP sebesar 4494 sm³. Temuan ini menunjukkan bahwa pengintegrasian metode-metode ini secara efektif menghitung cadangan hidrokarbon di batupasir ketat.*

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1. INTRODUCTION

Tight sandstone is a type of unconventional reservoir characterized by very low porosity and permeability, which restricts fluid flow (Lian et al., 2024). This condition necessitates the use of reliable approaches for reserve estimation and reservoir characterization. Due to its uncommon characteristics, tight sandstone reservoirs are highly susceptible to uncertainty, requiring a more representative and accurate approach. One commonly used method for estimating hydrocarbon reserves is static reservoir modeling. This method combines seismic data and well data to construct a structural model that depicts the distribution of facies, stratigraphic zones, and petrophysical properties. This model is crucial as a basis for volumetric calculations and the distribution of reservoir properties, assisting in evaluating the feasibility of field development.

However, previous studies have not focused on the integration of static modeling with pre-stack seismic inversion for tight sandstone reservoirs, which present unique challenges due to their uncommon geological characteristics. For example, the study by (Eleslambouly et al., 2025) for hydrocarbon reserve evaluation and estimation at the Penobscot Field in the Scotian Basin, Nova Scotia, Canada, relied solely on static modeling without utilizing the pre-stack seismic inversion technique. While static modeling has proven effective in mapping hydrocarbon reserves, uncertainty arising from data

limitations and the unique geological conditions of tight sandstone reservoirs remains a challenge.

Pre-stack seismic inversion is applied to obtain an acoustic impedance profile, which is used as a collocated property, ensuring that the property distribution in the model aligns with the impedance results generated by the inversion technique. The integration of pre-stack inversion and static modeling is expected to reduce the uncertainties that often arise during the modeling process, with the goal of producing a more detailed and reliable subsurface model. By utilizing seismic data before the stacking process, pre-stack inversion allows for a more comprehensive extraction of subsurface characteristics, working by considering seismic data from various angles of incidence of the seismic waves. This provides higher resolution and the ability to detect more complex subsurface layers, enabling a more accurate depiction of variations in petrophysical properties within the rock formation, such as density and P-wave velocity, which are essential for reservoir modeling.

In this study, we employ pre-stack seismic inversion and static model as a relatively new combination in reservoir characterization. According to (Hosseinzadeh et al., 2025), this technique is highly effective in converting seismic reflection data into the required physical properties of the reservoir, which directly influence the distribution of hydrocarbons within the reservoir. By utilizing richer seismic data, pre-stack inversion allows for better analysis of the subsurface model. This is particularly relevant for reservoirs with complex conditions, such as tight sandstone, which are characterized by low porosity and permeability. Pre-stack inversion enables more accurate modeling, ensuring that the subsurface model is sufficiently representative, with the hope of reducing uncertainty in reservoir modeling, providing a clearer picture of hydrocarbon distribution, and improving the accuracy of hydrocarbon reserve estimation.

Finally, this study aims to address this gap by integrating pre-stack inversion into static modeling, which is expected to provide a more accurate acoustic impedance profile, thereby reducing the uncertainty that often arises in tight sandstone reservoir modeling (Zhang et al., 2022). This study is expected to add contributions in the field of geostatistics for reservoir characterization and the effectiveness of reservoir volumetric estimation.

2. LITERATURE REVIEW

The Penobscot Field is located on the Scotian Shelf, offshore Nova Scotia, Canada, within the northwestern sector of the Scotian Basin (**Figure 1**). It illustrates the tectonic framework of the area and the position of the Penobscot Field. The basin was formed as a result of rifting during the Late Triassic to Jurassic periods, when the North American Plate separated from Africa and the opening of the Atlantic Ocean began. This extensional process generated a series of northeast–southwest (NE–SW) trending rift basins controlled by normal faulting, which later evolved into a non-volcanic passive margin (Royden & Keen, 1980). Furthermore, the dynamics of the Argo evaporite and subsequent salt deformation (halokinesis) played a significant role in the development of structural traps throughout the margin's evolution.

Regionally, the Scotian Basin begins with the syn-rift phase of the Late Triassic to Early Jurassic, comprising the Argo Formation, which consists of evaporite stacks (primarily halite) and carbonate rocks formed in a narrow, arid climate basin. Above this, the Eurydice and Mohican Formations dominate with clastic deposits (sand, silt, clay) from fluvial-deltaic and coastal systems. After the continental separation, the post-rift phase recorded transgression, transitioning to carbonate platforms and marine shale that cover the margin. From the Late Jurassic to Early Cretaceous, increased terrestrial sediment supply formed the Sable Delta Complex, resulting in large-scale clastic progradation. In the petroleum system framework, the Mississauga Formation (Early Cretaceous), consisting of fine to medium-

grained fluvial-deltaic sandstones, serves as the main reservoir, while the Logan Canyon Formation, dominated by pelitic shale, acts as an effective regional top seal. Further into the basin, the Verrill Canyon Formation, rich in organic material, serves as the key source rock (**Figure 2**) (Eleslambouly et al., 2025).

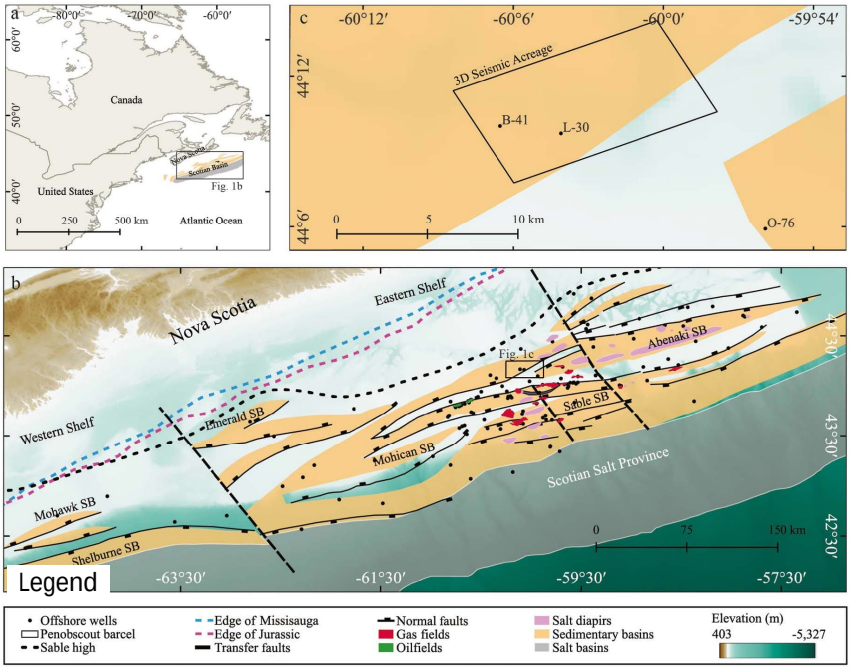

Figure 1. The regional map Scotian Basin (Eleslambouly et al., 2025).

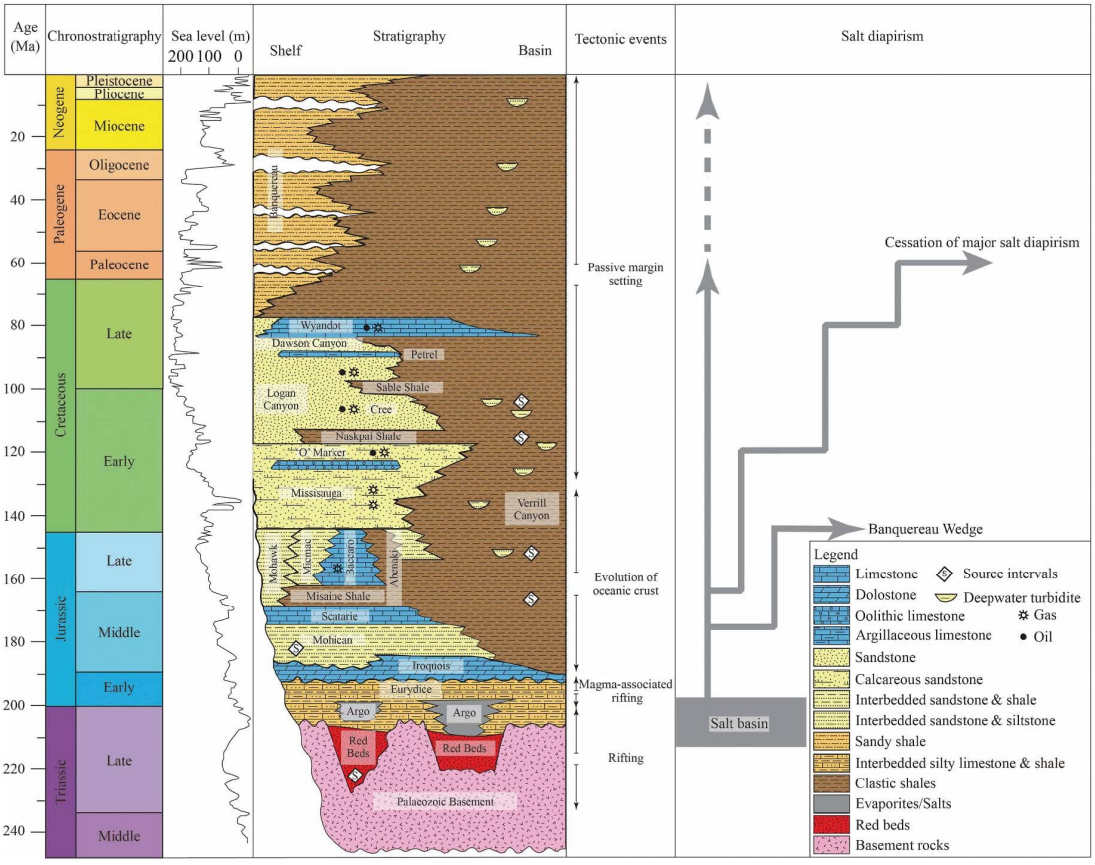

Figure 2. Stratigraphic column of Scotian Basin offshore Nova Scotia (Eleslambouly et al., 2025).

In the regional area of Penobscot, the structural control is characterized by an NE-SW trending anticline, which is cut by normal faults trending W-E. Some areas show indications of inversion at greater depths due to halokinesis (Decalf & Heyn, 2023; Eleslambouly et al., 2025; Wu et al., 2023).

Based on existing research, the sandstone in the Penobscot Field, which is part of the Mississauga Formation, locally exhibits characteristics of tight sandstone. In this field, tight sandstone begins to form through a diagenesis process involving compaction due to excess pressure, cementation, and the formation of bonds between sand grains, resulting in a dense sandstone (Campbell et al., 2015).

3. RESEARCH METHODS

3.1. Data Overview

The data used in this study includes 3D Pre-Stack Time Migration seismic data, which has been stacked to examine the continuity and patterns of the seismic structure, along with well log data, marker data, and checkshot data. The seismic and well log data used in this study are publicly available open-source datasets obtained from the Penobscot Field, Nova Scotia, Canada, provided by the Nova Scotia Department of Energy and dGB Earth Sciences. Additionally, well log data are used to supplement the research data. Two well logs are utilized: well B-41, which is a dry well, and well L-30, which is a productive well, as referenced in the literature shown in **Table 1**. The data from both logs include wireline log data and Vertical Seismic Profiling (VSP) data, specifically Checkshot, Gamma Ray (GR), Density (RHOB), Porosity (NPHI), Sonic (DT), and Resistivity (ILD).

3.2. Petrophysical Analysis

Petrophysical analysis is conducted to generate the necessary petrophysical logs required for determining the petrophysical properties in the target zone of the study, which are essential for volumetric calculations (Ramdhani et al., 2020; Sephiana et al., 2023). This is due to the fact that the available log data only includes wireline logs, which do not provide explicit information. Therefore, petrophysical analysis is necessary. The petrophysical log required for this study is the volume shale (V_{shale}), which is calculated based on the gamma ray (GR_{log}) using a linear index approach, as described in Equation (1).

$$V_{shale} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

Total porosity (ϕ_t) is calculated using the Wyllie Time-Average equation, as described in Equation (2), which relates the sonic wave transit time to the proportion of pore space in the rock.

$$\phi_t = \frac{\Delta T_{log} - \Delta T_{matriks}}{\Delta T_{fluida} - \Delta T_{matriks}} \quad (2)$$

Where ϕ_t is total porosity (fraction), ΔT_{log} is transit time from the sonic log (μs/ft), $\Delta T_{matriks}$ is the transit time of the rock matrix (μs/ft) and ΔT_{fluida} is $f$luid transit time in the pore space (μs/ft).

After the total porosity (ϕ_t) is determined, the effective porosity (ϕ_e) is then calculated by considering the pore space that fluids can traverse. The effective porosity (ϕ_e) is calculated by correcting the influence of shale content on total porosity (ϕ_t) using Equation (3).

$$\phi_e = \phi_t \times (1 - V_{shale}) \quad (3)$$

Water saturation (S_W) refers to the volume of the rock's pore space filled with water. In contrast, hydrocarbon saturation (S_h) represents the portion of the pore space occupied by hydrocarbons, calculated using the formula Hydrocarbon Saturation (S_h) = 1 - S_W. Equation (4) explains the calculation of water saturation, which is determined using the Archie equation, controlled by true resistivity (ILD) and resistivity of water (Sw) (Sephiana et al., 2023).

$$S_W = \sqrt{\frac{R_W}{(ILD \times \phi^{1.74})}} \quad (4)$$

Table 1. The completeness of the log data in the research field.

Well	X	Y	Surf. Elev.	KB	Wireline Log					VSP
					DT	***GR***	IL D	NPHI	RHOB	Checkshot
B-41	731143	4894511	-108.52	99	ü	ü	ü	ü	ü	ü
L-30	734539	4894062	-137.16	99	ü	ü	ü	ü	ü	ü

3.3. Seismic Interpretation

Seismic interpretation is carried out to construct the geometry of the research target. The seismic interpretation process includes two main aspects: fault interpretation and layer interpretation. In this study, the primary focus is on fault interpretation, where three faults were identified cutting through the research target. This process is assisted by the use of the variance attribute to identify amplitude discontinuities on the seismic map that has been input with this attribute. The interpretation results show two major faults trending west-east (W-E) and one minor fault trending west-southeast (W-SE) (**Figure 3**). The amplitude discontinuities detected using the variance attribute provide clear indications of the presence of faults in the area, which could play a significant role in the geological structure analysis of the study region.

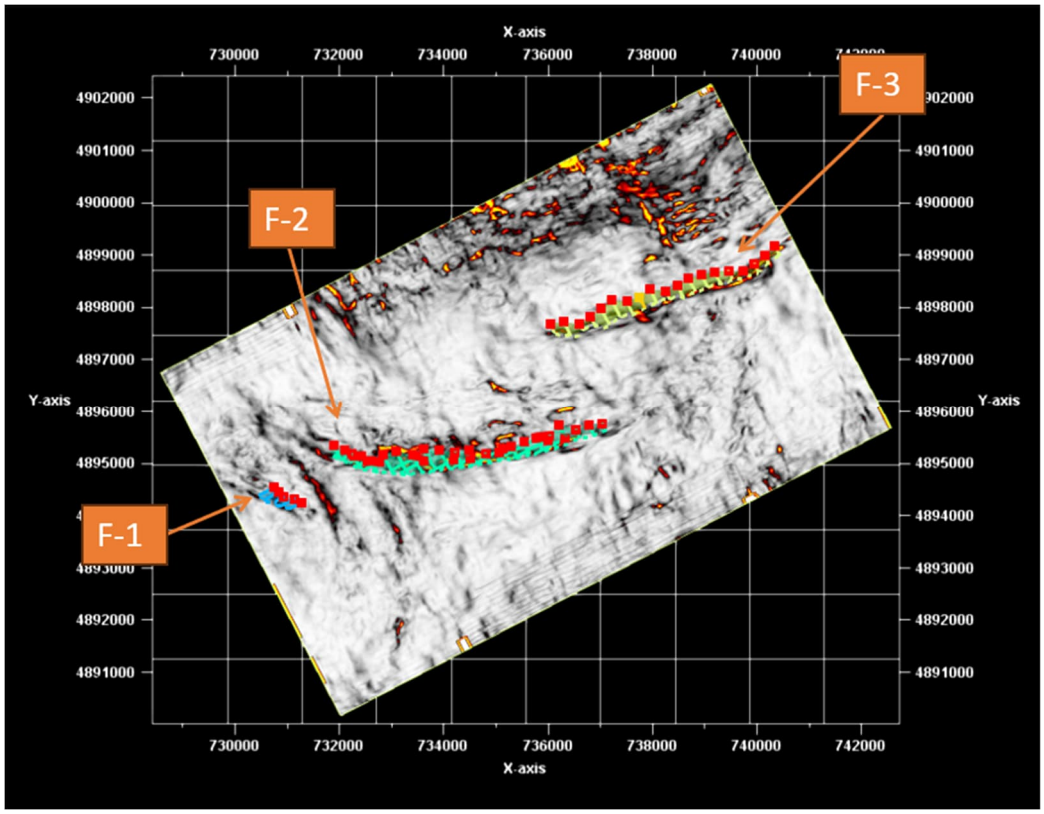

Figure 3. The results of the fault interpretation with the variance attribute.

Layer interpretation is carried out based on markers from the target zone of the study. The marker data used is created based on log values, with an analysis of the presence of sandstone that has high acoustic impedance values. **Table 2** shows the depths of the markers used.

Table 2. Marker data.

Horizon	Depth	
	B-41	L-30
TOP_TIGHT	2409.74	2407.63

BOT_TIGHT	2471.2	2468.49

The results of the layer interpretation produce a time structure map for both layers. **Figure 4A** shows the results of the layer interpretation, which reveal two significant structural peak zones, located in the South (S) and North (U) regions. The southern zone has been proven to contain hydrocarbons based on the drilling results from well L-30,

Subsequently, the time structure map was converted into the depth domain using a velocity model, resulting in a depth structure map as shown in **Figure 4B**. The resulting depth structure map provides a representation of subsurface structural geometry in actual depth units, thereby facilitating the identification of trap configurations, layer dip, and relative positions with respect to faults. In addition, this map enables a more reliable evaluation of hydrocarbon accumulation potential, as the estimated depth of structural tops and reservoir thickness can be quantitatively analyzed. Therefore, **Figure 4B** not only complements the information from the time structure map but also serves as an essential basis for exploration planning and the determination of subsequent drilling locations.

3.4. Pre-Stack Inversion

The integration of pre-stack inversion and a 3D static model is applied to enhance the accuracy of lithology distribution mapping in the target zone. Pre-stack inversion is used to analyze seismic data by considering variations in incidence angles, resulting in elastic parameters such as P-impedance (Zp), S-impedance (Zs), and the Vp/Vs ratio, which provide deeper insights into the elastic properties of rocks and the fluids contained within them. This approach does not rely solely on a single impedance parameter but instead uses multiple elastic parameters that reflect differences in seismic reflection responses. As a result, lithology can be analyzed based on the amplitude variations that occur in porous rocks containing gas or water fluids, as well as in sandstone and carbonate rocks, which produce significant variations in P-impedance (Zp), S-impedance (Zs), and the Vp/Vs ratio. These variations can be used to differentiate between rock types and the fluids contained within them (Al-Ashqar et al., 2025; Juventa & Fatkhan, 2021; Li et al., 2020).

3.5. Static Reservoir Modeling

The first step in constructing the 3D geological model is to build the structural framework, which serves as the foundation for distributing various geological properties. The method used to create this framework involves modeling faults and pillar gridding, based on the image in **Figure 5**. Once the basic framework is established, the next step is to upscale the log values, which are used to assign values to the 3D grid cells based on well log data. Since each cell can only contain one value, the well log data needs to be averaged. The quality of the logs generated through the upscaling process will be quality-checked by comparing histograms between the original logs and the upscaled logs (**Figure 6**). If there is no significant difference, the upscaled logs are considered valid and ready to be used in the next modeling stage.

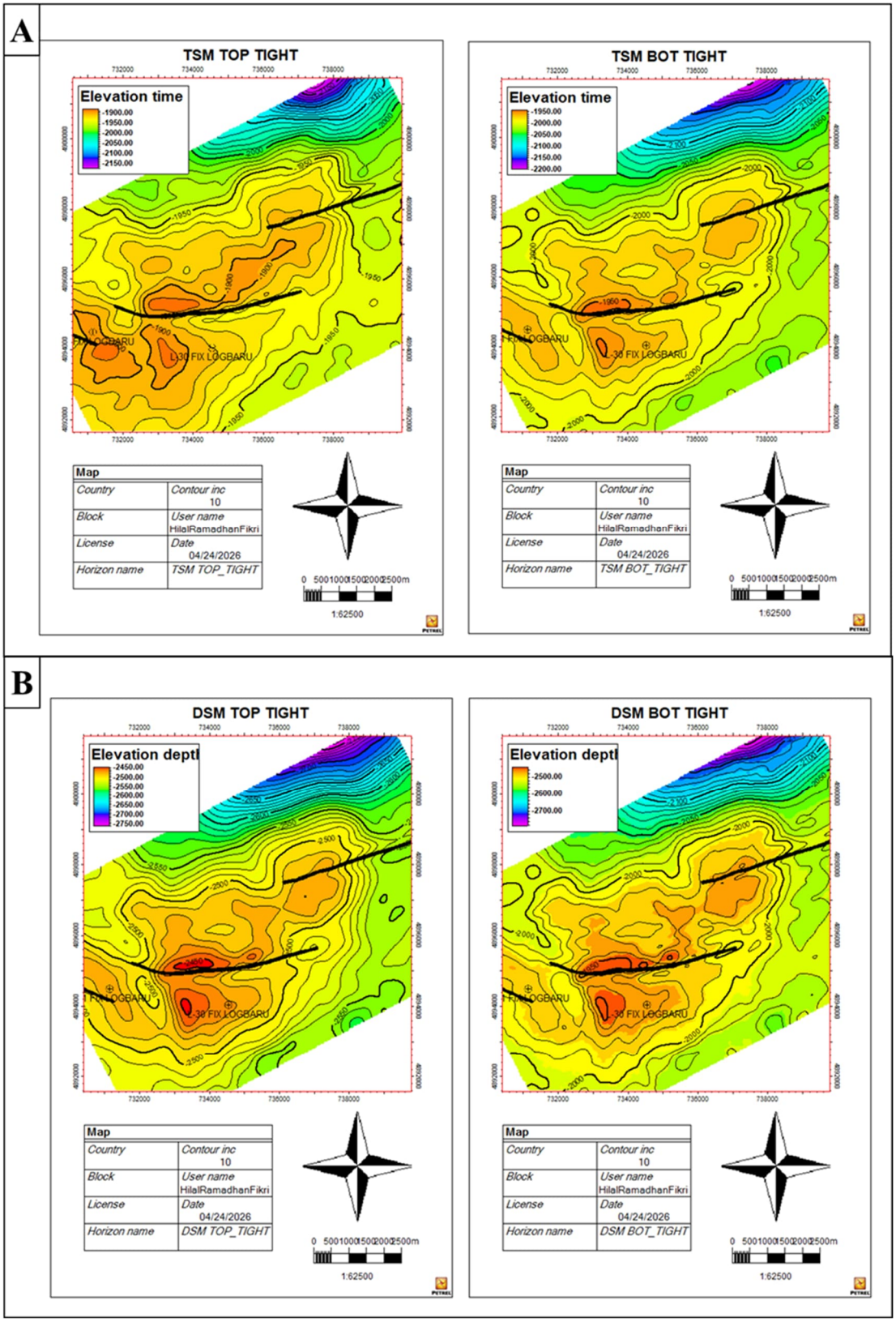

Figure 4. Result of (A) time structure map and (B) depth structure map of the targeted zone.

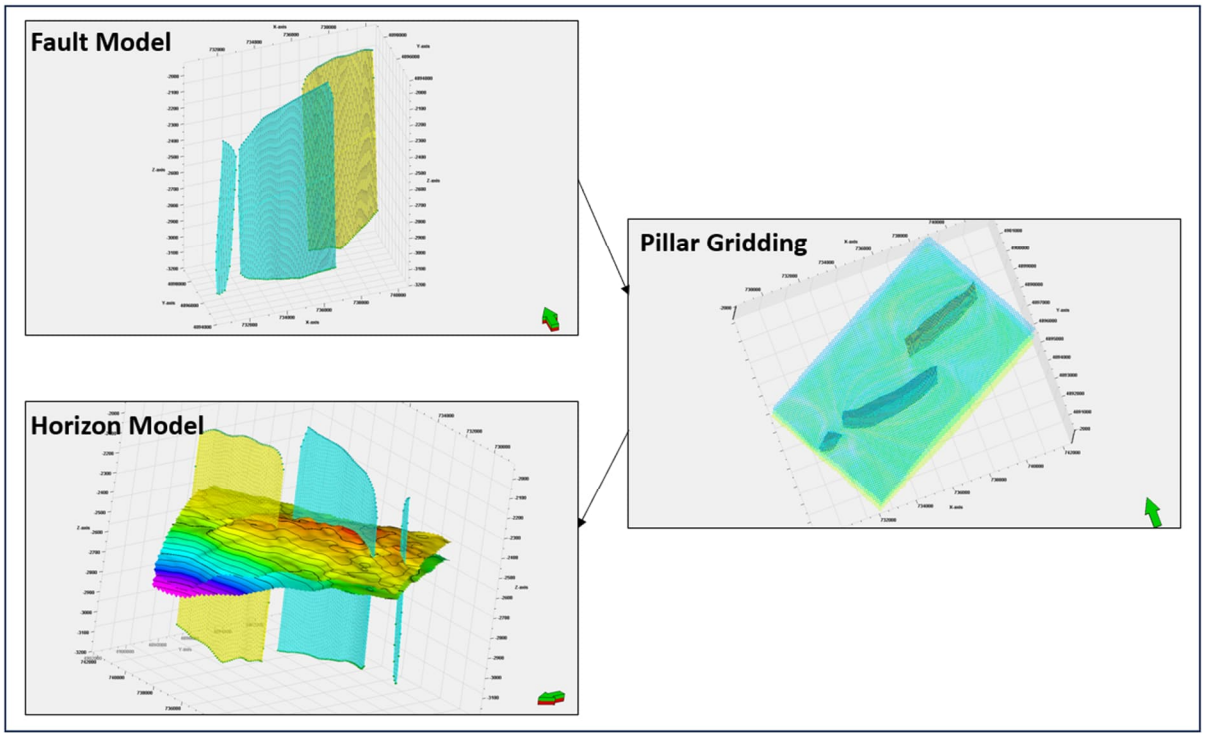

Figure 5. Structural framework of fault model and pillar gridding to input parameters of static modeling.

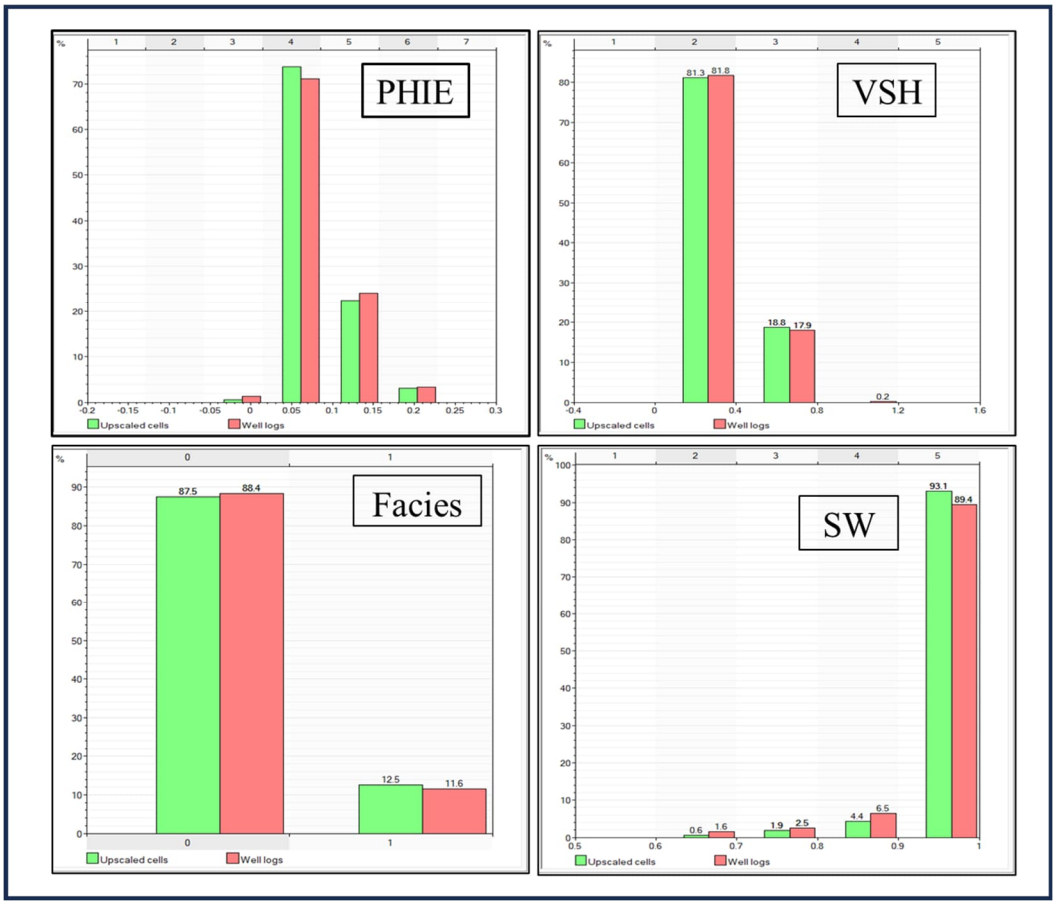

Figure 6. Quality control of an upscale histogram of all petrophysical parameters.

4. RESULTS AND DISCUSSION

4.1. Analysis Pre-Stack Inversion

The Pre-Stack inversion results in an acoustic impedance profile with values ranging from 4,066 to 13,800 (m/s)·(g/cc). Zones with low to medium acoustic impedance (AI) values 4.066-9,339 (m/s)·(g/cc) exhibit impedance characteristics of low shale. In this study, based on well-log calibration, which is crucial for accurate cementation interpretation, it is assumed that sandstone will exhibit higher AI values compared to shale due to compaction and cementation occurring during burial diagenesis. This is caused by cementation in the sandstone, which may be influenced by carbonate minerals or shale trapped within it. Salt is one of the factors that can affect the cementation of sandstone, making it more compact. The evaporite formation in the field can influence the reservoir quality above it through diagenesis and salt mobilization processes, leading to changes in the physical properties of the sandstone (Stricker et al., 2018). On the other hand, higher AI values >10,150 (m/s)·(g/cc) are dominant. **Figure 7** shows that the target zone of the study is dominated by tight sandstone, as reflected by the high AI values. Lateral variations in AI values indicate the distribution of tight sandstone influenced by stratigraphic control, with log data distribution and lateral variations showing good correlation, suggesting consistency in the pattern of tight sandstone distribution.

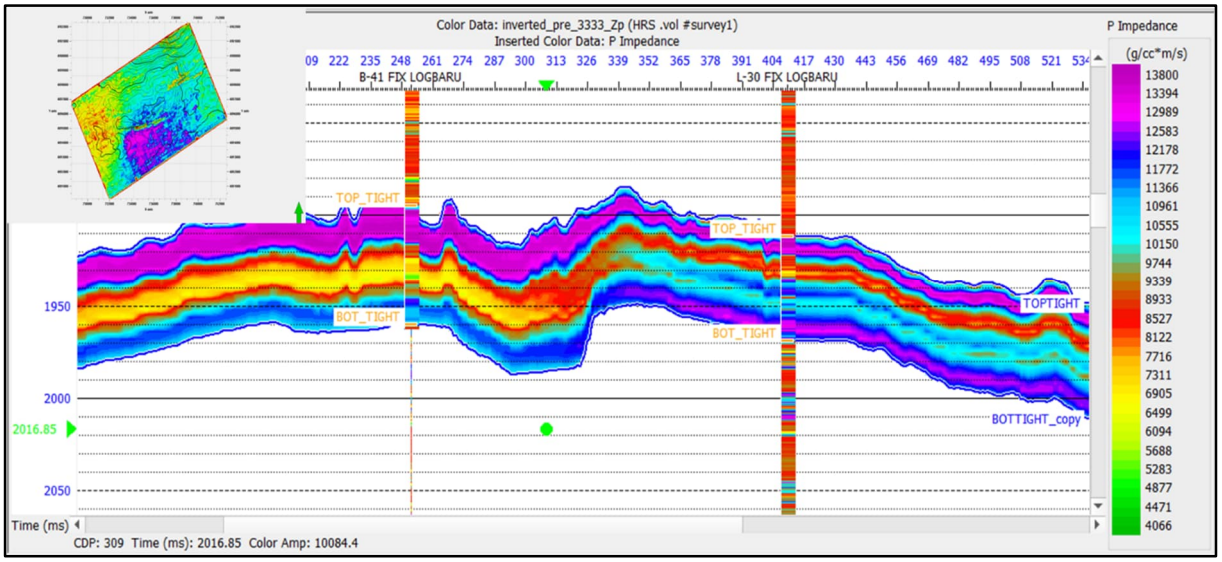

Figure 7. Result of Acoustic Impedance pre-stack inversion.

4.2. Property Modeling

According to the interpretation made by the Canada–Nova Scotia Offshore Petroleum Board (CNSOPB, 2007), the Penobscot Field is divided into three main hydrocarbon accumulation zones, structurally separated as South Penobscot, North Penobscot, and Northeast Penobscot, as shown in **Figure 8**. The South Penobscot zone has been proven to contain oil based on the results from the Penobscot L-30 well test.

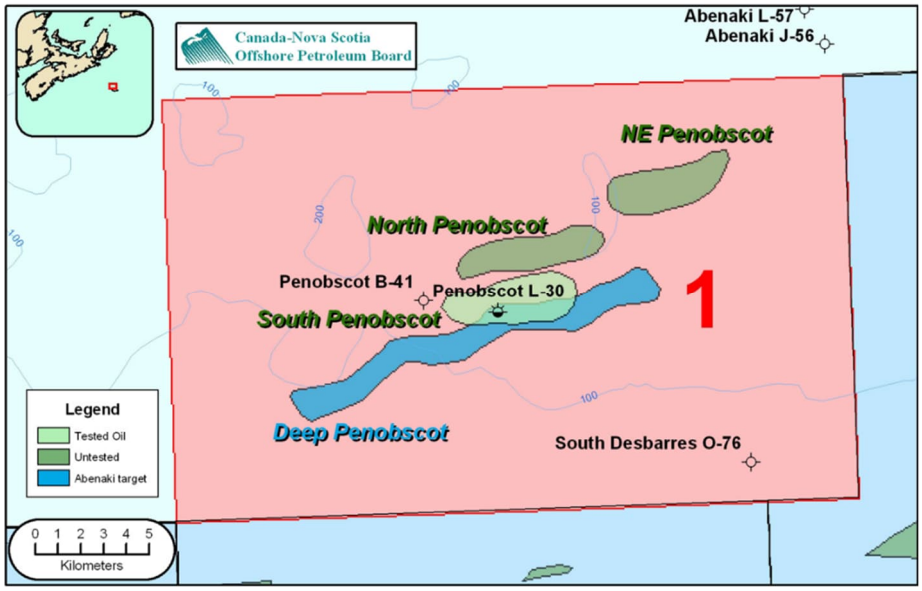

Figure 8. Reference map of hydrocarbon accumulation areas (CNSOPB, 2007).

The properties that have been upscaled for each well will then be simulated into the model. Facies modeling simulations will be conducted using the Sequential Indicator Simulation (SIS) method, with trends based on the results of pre-stack acoustic impedance inversion and variogram analysis. This approach is suitable for modeling facies or reservoir units with natural sequences. Meanwhile, petrophysical property simulations will use the Sequential Gaussian Simulation (SGS) method due to its ability to generate multiple realizations, which is crucial for addressing uncertainty. Important because estimations using interpolation often to varying results, even when the same input parameters are used. SGS can resolve this issue by providing a more robust solution (Handoyo et al., 2025). The results of the facies and effective porosity (ϕ_e) simulations, shown in **Figure 9**, present two 3D representations illustrating the distribution of facies and effective porosity values within the studied reservoir. **Figure 9A** displays the facies simulation results, where the facies distribution indicates that sandstone dominates the southern and northern parts of the field. At the same time, shale is more developed along the western edge. This pattern aligns with the justification provided in **Figure 8**, which shows the hydrocarbon accumulation zone that has already been tested in the southern part of the field. The facies distribution obtained is also consistent with the AI trend, showing that seismic data plays a crucial role in controlling the uncertainty of facies distribution. The distribution of effective porosity (ϕ_e), as shown in **Figure 9B**, follows a pattern that aligns with both facies and AI. with effective porosity (ϕ_e) values ranging from 0.01 to 0.18. The effective porosity (ϕ_e) simulation results are considered reliable, as the distribution of high effective porosity (ϕ_e) values is observed from the northern to the southern zone, marked by a contrasting reddish-yellow color around well L-30.

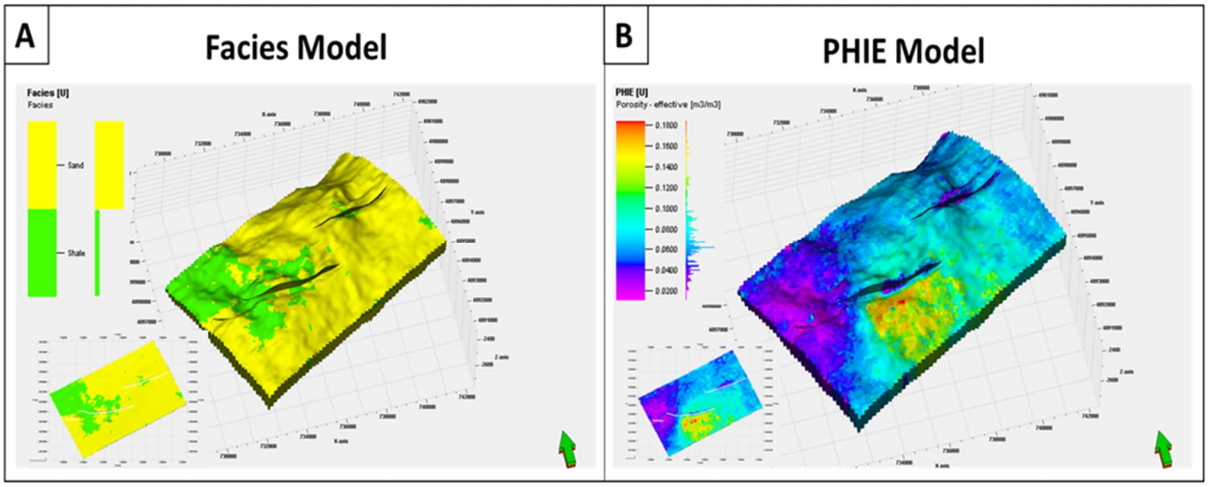

Figure 9. (A) Facies model, (B) effective porosity (ϕ_e) model.

The results of the volume shale (V_{shale}) and water saturation simulations provide patterns that help justify the distribution of hydrocarbon prospect zones and are crucial for reducing uncertainties in reserve calculations, as these layers have high hydrocarbon storage potential (**Figure 10**). **Figure 10A** shows a volume shale (V_{shale}) distribution range from 0.01 to 1, where low volume shale (V_{shale}) distribution associated with high effective porosity (ϕ_e) values, indicating a more prospective clean sand reservoir. Conversely, the blue zones with high volume shale (V_{shale}) values indicate the dominance of shale, which is non-reservoir. **Figure 10B** shows the water saturation (S_W) simulation, with dominant high water saturation (S_W) values range from 0.64 to 1. In contrast, low water saturation (S_W) values are found in small areas to the north and dominate the southern region, further strengthening the hydrocarbon accumulation map.

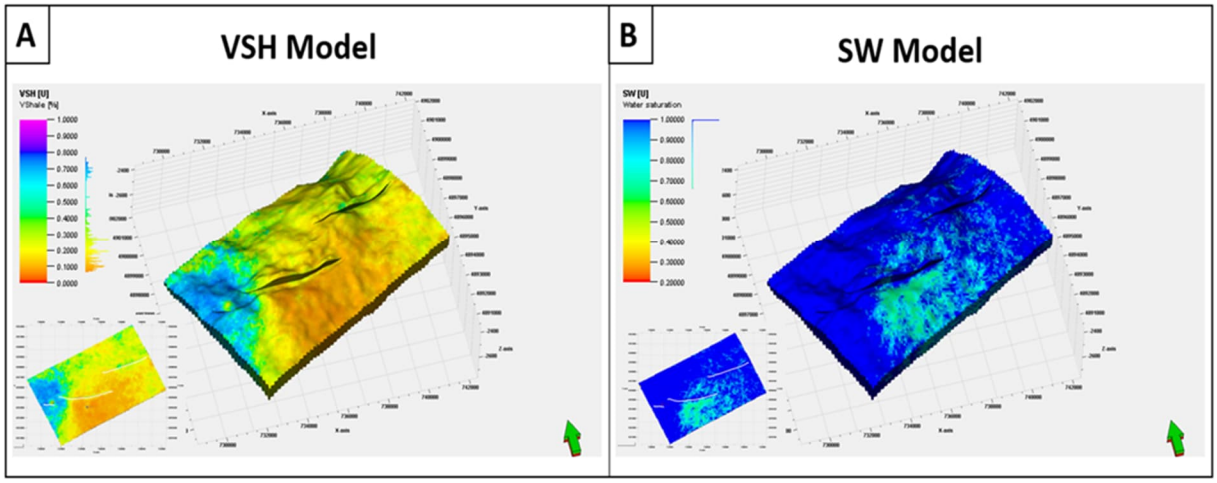

Figure 10. (A) Volume Shale (V_{shale}) model, (B) Water saturation (S_W) model.

The net to gross (NTG) model in **Figure 11A** shows the distribution of effective reservoir zones, generating a simulation pattern where sandstone with high fluid storage potential, characterized by net to gross (NTG) values ranging from 0.7 to 1.0, is located predominantly in the southern zone. This aligns with the results from the water saturation property model simulation, which indicates development potential related to the economic viability of the reservoir in the southern part. The net to gross (NTG) model is the ratio between the thickness of effective reservoir rock (net) and the total formation thickness (gross),

which includes the entire zone. The net thickness refers to the reservoir layers that can effectively store and transmit fluids. Based on well tests conducted by the Canada–Nova Scotia Offshore Petroleum Board (CNSOPB, 2007), the southern zone, specifically around Well L-30, shows potential hydrocarbon accumulation. With these net-to-gross (NTG) results and the dominance of tight sandstone, which tends to have relatively low porosity, the development is still considered economically viable for further exploration, though attention must be given to the available sample data from the field to ensure proper validation.

The net to gross (NTG) model is crucial for obtaining optimal and realistic reserve calculations. The simulation results can be validated both qualitatively and quantitatively by showing coordinated distributions and comparing histograms from the well logs, upscaled logs, and simulation results. **Figure 11B** displays the histogram results from the simulated and upscaled data, which show quantitatively convincing results, with no significant spikes between the three histograms. **Figure 12**. This indicates that the simulation results are valid and can be used for specific hydrocarbon reserve estimation calculations.

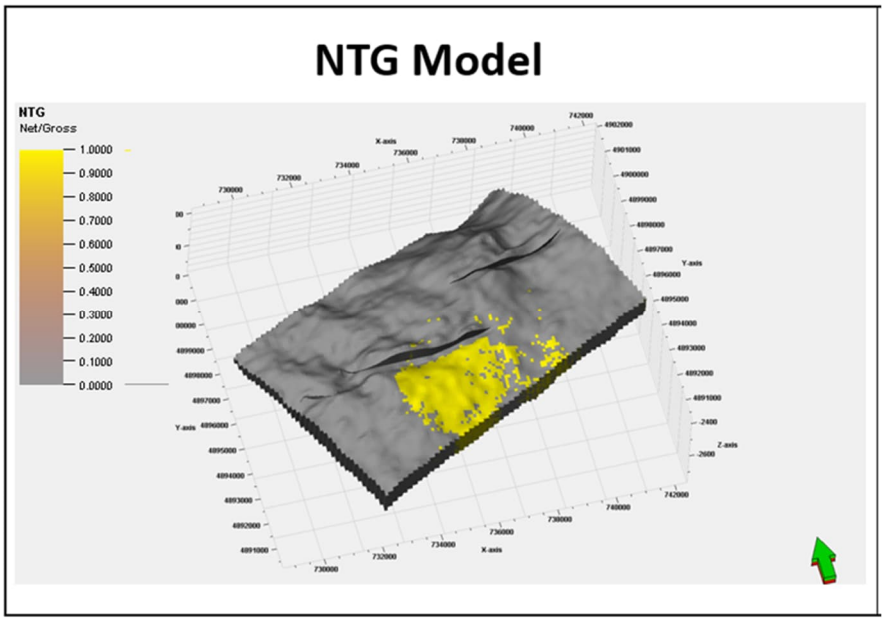

Figure 11. Net to gross (NTG) model result from simulation. Yellow area indicated reservoir target with high NTG value.

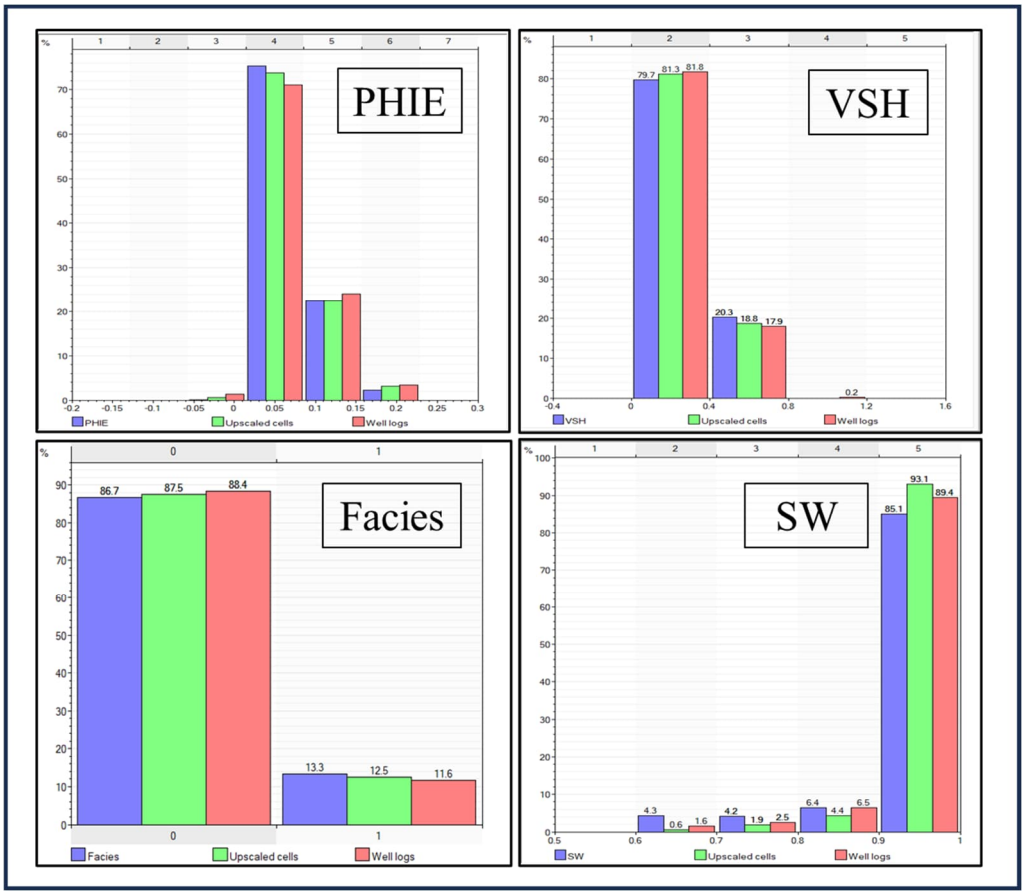

Figure 12. QC Simulation histogram of all petrophysical parameters.

4.3. Volumetric Calculation

To calculate the hydrocarbon reserve volume, a reservoir property model is required, which includes models for effective porosity (ϕ_e), Water *saturation* (S_W) and net to gross (NTG). Additionally, it is important to define the boundaries or contacts of hydrocarbon content used in the calculation; in this study, it only includes gas and water contact (gas-water contact). The calculation method used applies the STOIIP formula, as described in Equation (5).

$$STOIIP = \frac{GRV*NTG*\phi_e*(1-S_W)}{FVF} \quad (5)$$

The formula multiplies the gross rock volume (GRV) by the Net to gross (NTG), effective porosity (ϕ_e), and (1 - S_W), then divides the result by the formation volume factor (FVF). gross rock volume (GRV) represents the total rock volume, the net to gross NTG indicates the ratio of productive zones to the total formation, and effective porosity (ϕ_e) is the capacity of the pore space to store hydrocarbons. (1 - S_W) represents the proportion of pore space occupied by hydrocarbons, while formation volume factor (FVF) converts the hydrocarbon volume from reservoir conditions to surface conditions. Therefore, STOIIP provides an estimate of the hydrocarbon volume present in the reservoir based on these parameters.

Table 3 shows the volumetric calculations for the tight sandstone zone, indicating that this zone still contains hydrocarbon reserves. Although the tight sandstone reservoir has very low porosity and permeability, which limits fluid flow, hydrocarbon reserves can still be identified in this area. This suggests that, despite the physical characteristics of tight sandstone presenting challenges for exploitation, the reservoir still has the potential to store hydrocarbons, especially gas, which is more likely to flow through smaller pores compared to oil (Jiang et al., 2023).

Table 13. Volumetric Calculation for the Target Zone.

Hydrocarbon Reserves	Unit	Zone TOP_TIGHT-BOT_TIGHT
Bulk Volume	sm^3	6083
Net Volume	sm^3	702
Pore Volume	sm^3	96
STOIIP in gas	sm^3	4495
Recoverable gas	sm^3	1348

Overall, the estimated volumetric value of the target zone of 4495 sm^3 correlates with the average thickness of the well data **Table 2** of around ~63 m, indicating a fairly low reserve potential (Bate et al., 2023; Kurah et al., 2021). This is supported by the distribution of NTG in **Figure 11,** where the area predicted as a reservoir occupies a relatively narrow area.

However, it is important to emphasize that the volumetric results obtained represent the best estimate based on the variations in the data used. Therefore, the uncertainty of the calculations must be considered, particularly regarding variations in reservoir properties that could affect the reserve estimate results. Variability in key parameters such as porosity, net to gross (NTG), and hydrocarbon saturation significantly impacts hydrocarbon reserve estimation in tight reservoirs (Muldi, 2025; Yang et al., 2023). Differences in these parameters, both laterally and vertically, can lead to highly variable reserve estimates. For example, a zone with low net to gross (NTG) but high porosity may have smaller reserves compared to a zone with high net to gross (NTG) but low porosity. Variability in hydrocarbon saturation also affects production potential, as hydrocarbon distribution is not uniform. Data limitations, such as a limited number of wells and measurement inaccuracies, increase uncertainty in reserve estimation (He et al., 2025; Olutoki et al., 2024). Therefore, it is crucial to consider the variability of parameters and data limitations in reservoir modeling to obtain more accurate reserve estimates. Nevertheless, with the current volumetric approach, calculations for this zone can still be performed and provide a foundation for further analysis and reservoir model development.

5. CONCLUSION

Based on the modeling results, pre-stack seismic inversion with an acoustic impedance range of 4,066 to 13,800 (m/s)·(g/cc) is proven to effectively support reservoir property simulation. This range shows a consistent relationship with the distribution of effective porosity (ϕ_e) 0.01 to 0.18, volume Shale (V_{shale}) 0.01 to 1.00, and water saturation (S_W) 0.64 to 1.00. Such consistency allows the modeling process to be more controlled and results in a subsurface property representation that more closely reflects actual reservoir conditions. The alignment between petrophysical model trends and the acoustic impedance sections further indicates that the pre-stack inversion results provide a strong quantitative basis for static reservoir model development, while also contributing to the reduction of interpretation uncertainty.

The integration of seismic and well data within the three-dimensional static modeling framework demonstrates that the spatial relationships among reservoir properties have been well established. The resulting distribution of facies and petrophysical properties exhibits consistent and geologically plausible patterns, enabling a more realistic representation of subsurface conditions. Although the investigated reservoir is classified as a tight sandstone with inherent rock quality limitations, this approach remains effective in identifying relatively more prospective zones. These findings confirm that the integrative approach is more capable of capturing

reservoir heterogeneity than the use of well data alone.

Additionally, the volumetric calculations based on the constructed model indicate that the economically recoverable gas volume reaches 1348 sm^3. The target zone provides relevant volumetric estimates for non-conventional reservoir systems, suggesting that the results of this study can serve as a reliable basis for supporting reservoir development decision-making. Overall, this study demonstrates that, despite data limitations, the combination of pre-stack seismic inversion and static reservoir modeling represents a reliable and practical approach for evaluating tight sandstone reservoirs under complex geological conditions. However, for further study development, alternative approaches, such as dynamic modeling or fracture analysis, could be explored to validate the findings further.

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