Optimizing Field Development with Petrel-14: A Case Study of the Penobscot Field in Nova Scotia, Canada

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Abstract:

An optimized field development strategy at the initial stages of any oil and gas project plays a crucial role in achieving a maximized hydrocarbon recovery at minimal cost. It encompasses a broad range of disciplines, including subsurface studies, well and production technology specialists, surface facilities engineering, and economics of the project. This research aims to sketch an optimum field development strategy for the exploratory Penobscot field at offshore Nova Scotia of Canada through a comprehensive geological and geophysical study of the subsurface. Penobscot is considered in this research as it part of the public dataset provided by the Nova Scotia Offshore Petroleum Board (CNSOPB), which includes 2D/3D seismic data, well logs, interpretations, velocity models that are all freely available for academic and research use. The Repeat Formation Testing (RFT) which estimates the formation pressure, permeability, and obtains fluid samples, along with the Neutron-Porosity (NP) log which determine the porosity of a formation by measuring the hydrogen content within the formation are analysed to determine porosity, permeability, and water saturation of the reservoir. The hydrocarbon in place (HIP) is estimated based on these parameters, and the reserve volume is cross-checked with the results derived from RFT. The reservoir model building and development strategies are carried out using Petrel-14 software. Finally, based on the details of the subsurface studies three field development strategies are simulated by using an optimum number of producers and also, if required converting some producers into the injection wells for enhanced oil recovery (EOR). The three simulated development strategies of the field are 'two producers (existing L-30 and B-41 wells)', 'two producers and one injector', and 'three producers and one injector'. It is found that out of all the field development strategy with 'three producers and one injector' gives an oil production of 3.335 $\times 10^6$ m^3, gas production of 4.592 $\times 10^9$ m^3, water production of 3.744 $\times 10^5$ m^3 with a recovery rate of 20.84%, in a cumulative period of 5 years. The petroleum profit for this field development strategy is about \$ 82784897.2 which is higher than any of the other strategies.

Keywords: Development strategies, Petrel-14, Reservoir model building, Repeat formation testing, Well log data.

1. Introduction

Offshore hydrocarbon exploration is pivotal to global energy supply, especially in frontier regions like the Atlantic margin of Canada. The Penobscot field, situated offshore Nova Scotia, presents a technically intriguing and economically promising opportunity due to its structural complexity and untapped hydrocarbon potential. Despite earlier seismic surveys and exploratory drilling, the field remains underdeveloped, with limited production planning and uncertainties regarding optimal exploitation strategies. Previous studies have primarily focused on seismic interpretation and machine learning applications for seismic data analysis in the Penobscot field. For instance, the Penobscot interpretation dataset was introduced to advance machine learning in seismic interpretation by providing labelled seismic images for algorithm development [1]. A deep neural network architecture for semantic segmentation of seismic images using the Penobscot 3D dataset was later developed [2]. Additionally, a deep domain adaptation approach for seismic facies analysis was proposed, utilizing the Penobscot dataset as the target domain [3]. While these studies have enhanced seismic data interpretation, there remains a gap in integrated reservoir modeling that combines geophysical, geological, and economic factors to determine cost-effective and technically viable development strategies. This study addresses this gap by applying an integrated modeling and economic evaluation approach using Petrel-14 software to assess various well placement and reservoir management strategies for the Penobscot field. By comparing multiple development configurations ranging from primary depletion to water flood scenarios we aim to identify the most efficient and profitable strategy for field development.

The main objective of this study is to determine the optimal development plan for the Penobscot field that maximizes petroleum profit while minimizing capital and operational expenses. This objective is pursued through a combination of reservoir simulation, economic modeling, and scenario analysis, thereby contributing a practical framework for offshore field development in similar underexplored regions The approach adopted in this study aims to develop the Penobscot field by minimizing the development expenses with a maximized recovery, differs from traditional field development methods primarily through its emphasis on cost-efficiency, integration of advanced modeling tools, and data-driven decision-making. Conventional development strategies often rely on extensive drilling campaigns, generalized geological assumptions, and segmented workflows across disciplines, which can result in high operational costs and increased subsurface uncertainty [4]. In contrast, this study leverages a streamlined workflow using Petrel-14 to integrate seismic, well log, and reservoir data, allowing for precise structural and stratigraphic interpretations before committing to drilling operations. By building a high-resolution 3D model of the Penobscot field, the study identifies optimal well locations and minimizes redundant data acquisition and drilling. This integrated and model-driven approach not only enhances the accuracy of subsurface predictions but also substantially reduces exploration and development expenditures, thereby aligning with modern industry practices for economically marginal or mature fields [5].

The Penobscot field is often considered as a kind of “benchmark” or “model field” in the region because it’s a rare case of a well-documented, geologically interesting offshore field with freely available high-quality data, making it perfect for further research activities. Penobscot is part of the public dataset provided by the Nova Scotia Offshore Petroleum Board (CNSOPB), which includes 2D/3D seismic data, well logs, interpretations, velocity models that are all freely available for academic and research use. Moreover, it has a representative structure of hydrocarbon traps with faulted structures and stratigraphic features that make it ideal for studying structural geology and reservoir characteristics. Above all, it is small and geologically manageable field compared to massive offshore fields. Hence, it allows for a full-cycle study from seismic interpretation to reservoir modeling without the overwhelming scale of larger fields. This study aims to develop the Penobscot field in a way to maximize its production in consideration of its economic avenues. This was done on the software Petrel 2014 integrating all its aspects in building the reservoir model and development strategy. Petrel-14 is selected for this study due to its advanced capabilities in subsurface modeling, seismic interpretation, and reservoir characterization. Compared to earlier versions, Petrel-14 offers enhanced 3D visualization, improved integration with geostatistical tools, and more efficient handling of large datasets [6]. One of its key advantages is its ability to streamline multi-disciplinary workflows by integrating geological, geophysical, and reservoir engineering data into a unified platform [7]. This integrated approach reduces uncertainties in reservoir modeling and increases the reliability of volumetric estimations and simulation results. Furthermore, Petrel-14 supports a wide range of plug-ins and custom workflows, offering more flexibility compared to other software, which may lack comprehensive geostatistical modeling or integration capabilities [8]. Previous studies have demonstrated the robustness of Petrel in structural modeling and stratigraphic interpretation, particularly in complex geological settings [9]. These features make Petrel-14 a suitable and reliable tool for the scope and objectives of this study.

The model building considers the logs provided for the two wells (L-30 and B-41) in the field to allocate properties to the whole reservoir by property modeling [10]. The project starts from analysing the logs into the well section window and looking for the sand layer for which the geological model had been provided as an open source data. RFT evaluations on this wells ascertains that the gas oil contact lies no above than 2472 meters while oil water contact lies no lower than 2510 meters which gives us a pay zone of around 38 meters. The geological model provided for the field is at a depth of around 2540 meters which is around the sand layer 2 and below which lies an aquifer. After log analysis, the properties are assigned into the model grid, along with the rock physics and fluid characteristics. The log interpretation is done in the geology and geo-science aspect of Petrel 14, whereas the fluid properties and the rock physics are made in the reservoir and production aspect. Once the model is prepared, a new grid is created after making a polygon around the area of interest and the new grid is just restricted into that area of the polygon. Thereafter, the reservoir properties are up-scaled in the structure from the old grid, such that they lie in the proper range for whole of the reservoir. The next step is to calculate the hydrocarbon volumes present based on the properties like porosity, permeability and water saturation derived from well logs. These calculated volumes are checked and confirmed with the hydrocarbon volumes estimated based on the RFT done in each of the wells. The acceptable range for variation from the estimated and calculated is not be more than 10%. The final step is developing the field by producing through it and if required drill more wells to use them as producing wells or even convert some wells to injection wells for improved oil recovery (IOR). These decisions are made based on the cost estimations for each well to be completed and cost required for it to bring into production or injection on a daily basis. The last step is to consider the economic avenues of each of the field development plans, which would consider the total input cost for developing the field including all the new drilled wells and their daily production or injection cost. By taking some bench mark for the crude price it is attempted to evaluate the best suited development strategy for the field with a maximum recovery factor.

This study demonstrates that a development strategy incorporating three producing wells and one injection well is the most technically and economically favourable approach for the Penobscot field, located offshore Nova Scotia, Canada. Among all evaluated scenarios, this configuration achieved the highest projected petroleum profit of approximately $82.78 million, highlighting its financial viability. The inclusion of an injection well not only enhances hydrocarbon recovery by maintaining reservoir pressure but also ensures more uniform sweep efficiency, thereby optimizing resource utilization. These results affirm that this strategy offers a robust balance between capital efficiency and production performance. Consequently, it stands out as the optimal field development plan from both quantitative and economic perspectives, providing a valuable decision-making framework for similar offshore exploratory fields. The integration of reservoir simulation with economic modeling, as demonstrated in this study, should be adopted as a standard workflow for decision-making in similar offshore fields.

2. Methodology

2.1 Geological Setting of Penobscot Field

The Penobscot field lies in the sable sub-basin, in which 23 other offshore discoveries have been already established. Many seismic surveys have been carried over the Penobscot field including 3D seismic for improved data acquisition quality. The Penobscot field is divided into two parts, one towards south of the main fault which had recovered oil and gas from several zones by performing RFT. This reservoir which is considered to be the southern part of the Penobscot field is interpreted to be trapped in a 4-way dip closure which is supposedly created on the downthrown side of a down to the basin growth fault [11]. Whereas the north-eastern structure has a closure against a different fault other than the main fault of Penobscot field. The main fault which is at the centre of the field is an evidence of the structure within the Jurassic period and this early movement may supposedly have generated hydrocarbon fluids into the system. The map in figure 1, shows the location of the Penobscot field along with the two wells (L-30 and B-41) which have been drilled for exploration purpose. The well L-30 had commercial oil discoveries in the middle Mississauga sandstones while the well B-41 did not show any considerable hydrocarbon shows and hence was concluded to be a dry well.

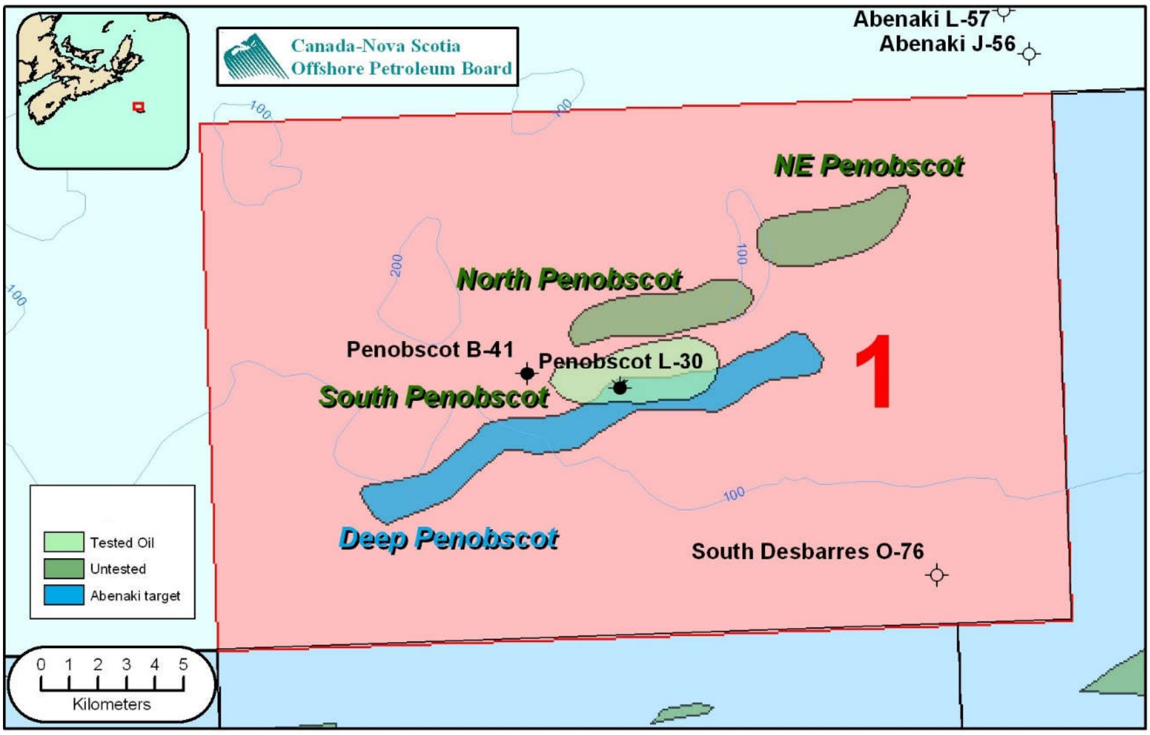

Figure 1: Penobscot Field Location [13]

It was in the exploratory phase in which two wells (L-30 and B-41) had been drilled and coring, logging and reservoir formation testing (RFT) had been done in certain sand layers [13]. Data for different sand layers was recorded from both the wells and hydrocarbon estimate was made [13]. In summary, exploration activities in the Penobscot Field have included 3D seismic surveys and the drilling of exploratory wells, such as Penobscot L-30 and B-41. While these wells encountered hydrocarbon shows, commercial development has yet to be realized. Nonetheless, the field remains an area of interest due to its geological characteristics and potential for future hydrocarbon production.

2.2 *Formation Evaluation*

Primary well logs are performed on both the wells (B-41 and L-30) in the Penobscot field which lie in the south Penobscot field (i.e.; south of the fault present in the field). Coring operations were also performed in the wells. Two cores retrieved from well L-30 are however, found to be below the reservoir interval. As a result, these cores do not provide direct information about the reservoir rock properties or hydrocarbon potential within the target interval. Four cores were retrieved from well B-41 which were within the reservoir interval. These cores are therefore representative of the reservoir rock and provide valuable data on porosity, permeability, lithology, and other reservoir characteristics. The results of the core analysis for well B-41 are presented in Table 1, offering critical insight into the reservoir's quality and production potential. The 3 cores from 2499.2 to 2670 m intervals show good potential of hydrocarbons presence but the fourth core from 2699 – 2717.9 interval has low potential of the same. This can be due to its coring interval lies below the producing zone on well B-41.

Table 1: Coring Analysis of well B-41 [13]

Core Samples	Interval	Estimated Recovery
1	2499.4 – 2517.6 m	17.4 m
2	2642.6 – 2660.9 m	14.3 m
3	2660.9 – 2670.0 m	8.2 m
4	2699.0 – 2717.9 m	3.05 m

Routine core analysis was performed on the retrieved cores from different intervals of well L-30. Tables 2 present the reservoir zone properties for the Penobscot Field as interpreted from well logs and core data. These tables summarize critical geological and petro-physical parameters that define the quality and extent of potential hydrocarbon-bearing sands within the field. Understanding these parameters is essential for evaluating reservoir productivity, volumetric estimation, and well placement decisions. Table 2 presents fluid sample analysis across multiple sand intervals encountered in the Penobscot Field. Among these, Sand 1 and Sand 4 demonstrate the most favourable reservoir characteristics. Sand 1 yielded 3,400 cc of condensate and 1 cubic feet of gas, with no associated water, suggesting a high-potential, clean pay zone. Similarly, Sand 4 exhibited consistent hydrocarbon saturation with multiple samples yielding up to 3,800 cc of condensate and minor gas volumes, indicating robust productivity potential. In contrast, Sand 2 and Sand 3 show mixed results: while one sample from Sand 2 contains 900 cc of oil and 8,000 cc of water, other samples are located below the interpreted oil-water contact (OWC) and yielded only water, limiting their economic viability. Sand 3, situated marginally above the OWC, yielded negligible hydrocarbons and is therefore classified as a low-yield interval. Lastly, Sand 5 is clearly identified as a transition zone, with all samples containing only water and no hydrocarbons, indicating non-productive characteristics in its current state. These observations are crucial for refining the reservoir model and optimizing well placement strategies. The average porosity obtained from the core analysis are calculated to be 20% to 32% and the average permeability of are calculated to be between 120 mD to 1000 mD.

Table 2: Fluid recovery report from core analysis of L-30 Well [13]

Sand	Depth (m)	Oil/Condensate (cc)	Gas (cu ft)	Water (cc)	Remarks
1	2480.2	3400 (condensate)	1	nil	
2	2504.8	900 (oil)	nil	8000	
2	2509.4	nil	nil	10250	Below OWC
2	2509.4	nil	nil	3750	Belo OWC
3	2545.4	100 (oil)	0.5	10000	< 1m above OWC
4	2639.3	3800 (condensate)	10	5200	
4	2639.3	3000 (condensate)	5	nil	
5	2700.5	nil	nil	10250	Transition Zone
5	2700.5	nil	nil	3750	Transition Zone
5	2700.5	nil	nil	9700	Transition Zone

Table 3 outlines the petro-physical properties of key sand intervals in the Penobscot Field evaluated after the core analysis and the RFT's performed in the L-30 well, with a focus on net pay, porosity, and water saturation (S_w). Among the evaluated sands, Sand 2 emerges as the most promising interval, displaying a net pay thickness of 4.6 m, porosity of 21%, and a moderate S_w of 46%, indicative of effective hydrocarbon storage and potential for commercial production. Sands 1, 3, and 4 also exhibit net pay thicknesses ranging from 1.2 to 4.3 m, with porosities between 18–19%, and S_w values under 50%, suggesting additional viable targets for exploitation. In contrast, Sand 3A is interpreted as a wet zone, while Sands 5 through 7 show negligible net pay (<0.5 m) and lack petro-physical data, suggesting poor reservoir quality or water-dominated intervals. These findings, when integrated with core fluid recovery data (Table 2), reinforce the selection of Sands 1, 2, and 4 as key contributors to the field's productive potential.

Table 3: Reservoir Properties of different sand layers in L-30 Well [13]

Sand	Top (m MD)	Base (m MD)	Net Pay (m TVD)	Net Pay Porosity (%)	S_w (%)
1	2477.6	2484.9	1.2	19	49
2	2503.0	2530.9	4.6	21	46
3	2542.0	2546.6	2.1	18	41
3A	2558.5	2594.6	Wet	N/A	N/A
4	2638.0	2669.0	4.3	19	45
5	2699.2	2758.5	<0.5	N/A	N/A
6	2795.5	2805.4	<0.5	N/A	N/A
7	2835.3	2912.8	<0.5	N/A	N/A

The well L-30 has been drilled on the flank of the south Penobscot and thus, very thin oil column is found within it. According to the study sand layer number 5 to 7 have oil-water contacts within a few meters of the top of each sand layer. The RFT's are performed just 2 m above the interpreted oil-water contact in the sand layer 5. This layer has its upper portion within the transition zone of oil and water presence with a S_w value of 70%. These sand layers have a very thin pay over water at the top of each sand layer, which says that sand layer 5 is the transition for the oil-water contact.

2.3 Seismic Data Interpretation

The seismic data utilized in this research is a pre-stack non-NMO, multichannel, and folded marine data set acquired by Western Geophysical Company on behalf of the Nova Scotia Resources on 8 June 1985. 2-D seismic lines are obtained from the data published by CNSOPB-2000: Geoscience Research Centre (GRC). Pre-stack and post-stack processing are conducted to enhance signal-to-noise ratio of the Penobscot marine 2-D data set. Reprocessing is conducted in this study to improve resolution, sharpen the faulted structures, and increase the layer continuity for structural interpretation. Figure 2, shows the spatial layout of two wells B-41 and L-30 in relation to seismic lines Line 44, Line 45, and Line 3X within the Penobscot Field Offshore Nova Scotia, Canada. The B-41 well, marked with a black circle, and the L-30 well, marked with a green circle, are positioned near the intersection of Line 3X and Line 44, with L-30 located slightly closer to this seismic intersection.

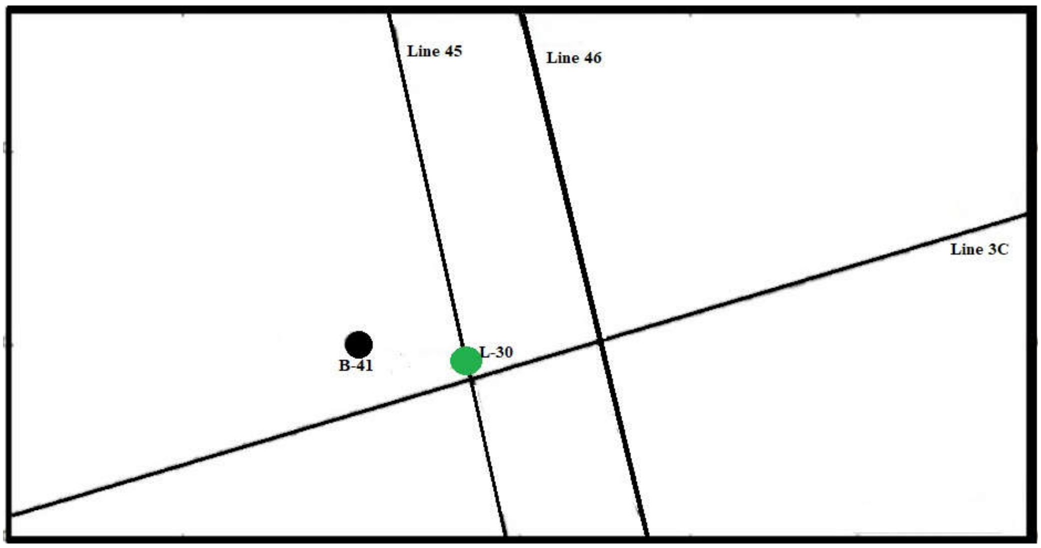

Figure 2: The base map of the research area. Lines 45 and 46 intersect with Line 3C.

The distance between Well L-30 and Well B-41 is 3.2 km. Well L-30 is located on Line 45 and used to generate a synthetic seismogram for horizon interpretation. Both lines 45 and 46 contain highly faulted structures due to a fact that they are perpendicular to the major down-to-basin listric fault system as shown in Figure 2. Line 3C was located parallel to the faulted region. As a result, Line 3C exhibits horizontal formations with no termination, such as faults or angled structures. Lines 45 and 46 have major uplifted faulted structures merged with a low relief anticline, which was drilled by Well L-30, which encountered hydrocarbons in the Mississauga Formation Sands [2000]. In this study, the petro-physical properties are assumed based on different studies that were carried on either the similar type of formation or are taken from the adjacent field of Cohasset and Panuke, which are just 60 km away from the Penobscot field. The assumptions are made as realistic as possible to make a better model so that a proper field could be developed. The assumptions used in correlation of other nearby fields for several parameters are; oil formation volume factor (B_o) is 1.25, gas formation volume factor (B_g) is 0.8, water saturation (S_w) is 0.45, Solution gas-oil ratio (R_s) is 1.5 and oil saturation (S_o) is 0.1.

2.4 Building Penobscot Reservoir Model

The reservoir model is built using the geology and reservoir software Petrel 2014 as shown in figure 3. The image presents a 3D structural contour map, generated from seismic or subsurface modeling data. The map uses colour gradients and contour lines to depict structural elevation (depth) variations across the reservoir interval. Figure 3, shows a color-coded 3D structural contour map illustrating the topography of a key reservoir interval. The map uses a spectrum from red (highest elevation) through green (intermediate elevation) to blue (lowest elevation) to represent structural depth variations across the mapped area. The red zones correspond to structural highs or crests, which are the most favourable targets for hydrocarbon accumulation due to their potential as structural traps. The green zones represent transitional flanks of the structure, which may still hold recoverable hydrocarbons depending on local reservoir characteristics. The blue zones indicate structural lows, which are typically water-bearing or below the oil-water contact. The figure also includes two intersecting lines representing seismic sections or well trajectories, aiding in the correlation of subsurface data. Contour lines clearly define the structural relief, with closely spaced contours indicating steeper gradients. The orientation arrow in the bottom right corner denotes geographic north, supporting spatial reference for field development planning. This visualization is essential for delineating optimal drilling targets, understanding trap geometry, and guiding reservoir development strategies.

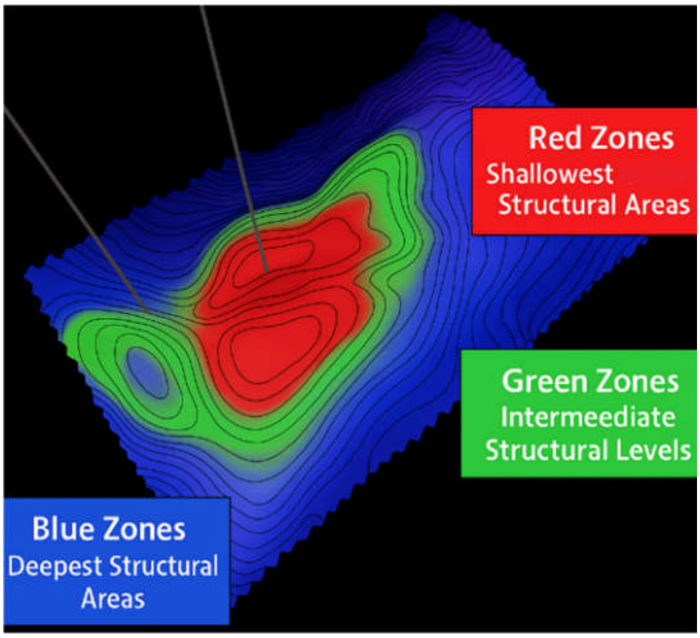

Figure 3: Geological Model of the Penobscot Field

All field properties were derived based on well log interpretation and core analysis, in accordance with established methodologies [15, 16]. In addition to building the geological model, detailed log data for both wells L-30 and B-41 were analysed and are presented in Figure 4. Among the log types examined, neutron porosity logs were particularly important for estimating porosity in shale intervals and for identifying potential hydrocarbon-bearing zones, particularly the presence of oil or gas [17]. The geological model was supported by data from two key wells L-30 and B-41 for which detailed log analyses were performed. As illustrated in Figure 4, various well logs were interpreted, including gamma ray, resistivity, and neutron porosity logs. Among these, neutron porosity was particularly critical for assessing shale porosity and detecting the presence of hydrocarbons, notably oil and gas

[17]. The target reservoir interval identified for development lies between 2472 meters and 2510 meters' depth. This interval corresponds to a sand-rich zone with favourable porosity and hydrocarbon saturation values, as corroborated by both core recovery and log signatures. Within the well section window (Figure 4), the top and base of this reservoir are clearly defined and marked by the MM Reservoir Horizon. This horizon has been traced across both wells L-30 and B-41 indicating lateral continuity and serving as a reliable structural marker for correlating reservoir zones.

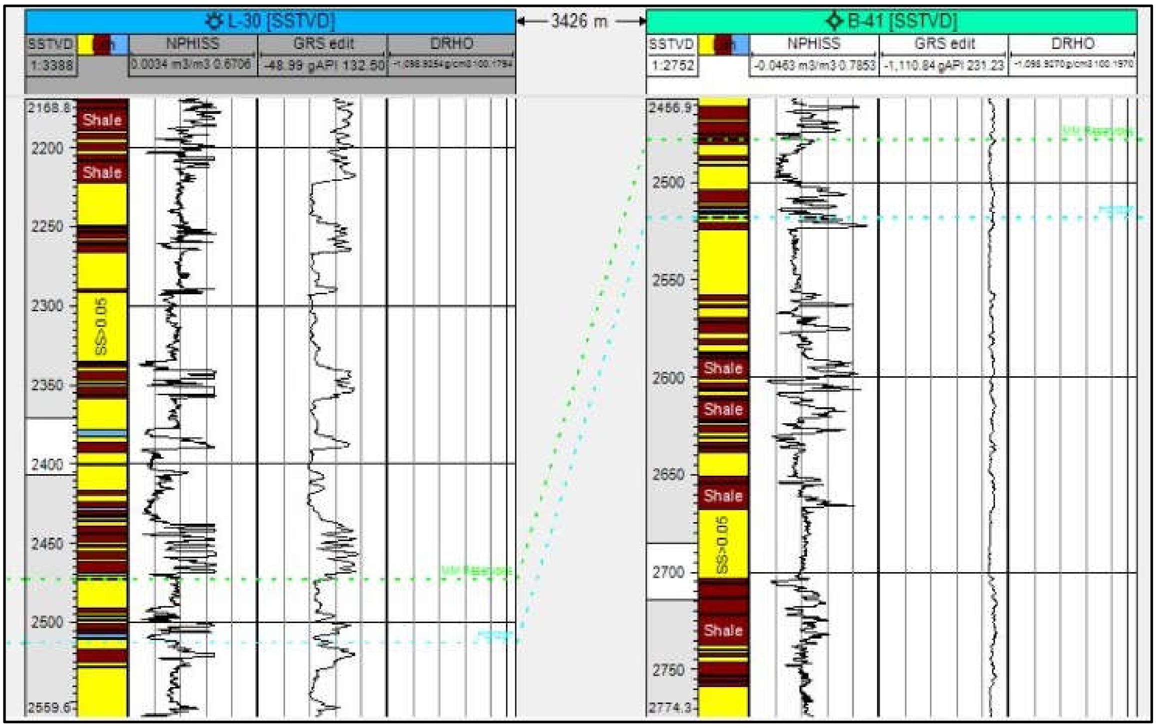

Figure 4: Well Section window with multiple logs for L-30 and B-41 wells (green line representing MM reservoir and blue line representing horizon)

2.5 Static Model Development

Static model includes developing a reservoir model based on the properties, like; porosity, permeability, compressibility and rock physics [18]. These properties are interpreted from the well logs and core analysis of the two wells drilled in the south Penobscot field. Porosity is allocated using the neutron-porosity log of both the wells through log upscaling option in the property modeling tab [19]. Once the well logs are upscaled it will create a property in the properties drop down for the active grid and these properties are allocated to the whole grid by petro-physically upscaling the log. In this study, Timur's empirical equation was selected for estimating permeability from well log data due to its proven reliability in clean sandstone formations and its compatibility with the available porosity and irreducible water saturation (S_{wir}) data. Timur's equation, which relates permeability to porosity and irreducible water saturation, is particularly advantageous in fields such as Penobscot, where core permeability data may be sparse or incomplete, and where clean clastic lithologies dominate the reservoir interval [20]. Timur's equation is expressed in Equation 1:

$$k = \frac{a.\phi^b}{S_{wir}^c}$$

Equation 1

Where: k is permeability (mD), ϕ is porosity (fraction), S_{wir} is irreducible water saturation, a, b, c are empirical constants (typically: $a = 0.136$, $b = 4$, $c = 2$).

Compared to alternative models like the Coates-Dumanoir method, which relies heavily on NMR-derived parameters and the Wyllie-Rose correlation which depends on capillary pressure data and pore geometry assumptions, Timur's equation provides a pragmatic solution that balances accuracy and simplicity when only conventional log data are available. This makes it especially suitable for the early phases of reservoir evaluation or in exploratory wells where advanced measurements are limited. Moreover, previous studies have successfully applied Timur’s equation in analogous sandstone reservoirs under similar geological conditions supporting its application in the Penobscot Field [16, 21].

When all the parameters are inserted into the volume calculation tab, like porosity, water saturation, gas saturation, oil saturation, gas formation volume factor, oil formation volume factor, gas oil ratio, volatile gas oil ratio, gas oil contact (GOC), oil water contact (OWC), oil properties, gas properties, and water properties it calculates the static volume of oil in oil phase, volume of oil in gas, volume of gas in gas phase, and volume of gas in oil phase. It prepares an excel sheet to give the total pore volume and the static volume of oil and gas. Well B-41 was found out to be a dry well with no significant hydrocarbon shows, while north and north-eastern region of the Penobscot field has good potential of discovery. This suggests potential lateral heterogeneity in reservoir quality or structure, possibly due to localized compartmentalization, seal failure, or unfavourable depositional environments in that sector of the field [22]. The absence of hydrocarbons at B-41's location supports a more conservative estimation of the reservoir extent, guiding the refinement of property distributions in that region of the model. This potential is possibly the carbonate formation of Jurassic age encountered in well L-30 [23]. The south Penobscot is a region below the first fault in the field. It has two wells L-30 and B-41 in which core analysis was also performed and hence the south Penobscot has proven oil and gas reserves, while no exploratory wells were drilled in the north and north-eastern part of the field and hence has probable reserves. The initial validation of the developed static model involved a direct comparison between the simulated petro-physical properties (porosity, water saturation, and net-to-gross ratios) and the original well log data from wells L-30 and B-41. Cross-sections through the model were generated along well paths to assess how accurately the model reproduced the observed log responses. Good agreement between the modeled and logged values within reservoir intervals confirmed the robustness of the model. The structural framework was cross-validated using seismic interpretation and horizon correlation between the two wells. The MM reservoir horizon, delineated through seismic and well data, showed consistent depth trends and structural conformity across the field, supporting the geological model.

2.6 Dynamic Model Development

2.6.1 Well Log Upscaling and Property Making

In this study, well log data from the Penobscot field were upscaled to match the vertical resolution of the geological model. The upscaling was performed by focusing specifically on the reservoir zones intersected by the wells, thereby ensuring that only the log data relevant to the productive layers were considered for modeling [24]. The upscaling process involves averaging or transforming log values (such as porosity, water saturation, and volume of shale) across the grid cell thickness using appropriate statistical or mathematical techniques. In this case, methods such as arithmetic averaging, geometric averaging, and spherical distribution functions were applied depending on the heterogeneity and nature of the reservoir property. This allowed for accurate translation of log data from high-resolution depth intervals to the model scale. Following upscaling, the reservoir properties such as porosity, water saturation, and net-to-gross were generated using the property calculator function within the modeling environment. This step transforms the upscaled log data into spatially distributed properties that are usable within the static reservoir model [24]. This was done using facies-based and zonal averaging techniques, ensuring that the property distributions honoured both well log measurements and the geological framework. The use of distribution functions to interpolate properties either from individual wells or a combination of multiple wells allowed for realistic spatial variability within each reservoir zone [25].

The property calculator tab enables users to create new property volumes by applying mathematical expressions or conditional logic to the available logs. In this study, the process involved selecting an upscaled log from the properties tab, inserting it into the calculator using the "include" arrow function, and then formulating expressions relevant to each property. For instance, effective porosity was derived using a conditional function that accounts for shale volume thresholds, while saturation properties were computed using Timur-based equations, depending on data availability [16]. Once a new property was computed, it was stored in the model’s property database and could be visualized in the 3D model window. This visualization allowed for real-time quality control of property distribution across the model grid, ensuring that trends observed in the well data were adequately preserved throughout the reservoir.

2.6.2 Porosity Predictions

Porosity is defined as the void space available for fluid storage. Its prediction for the Penobscot field was primarily conducted using Repeat Formation Tester (RFT) data and core analysis from the two exploratory wells drilled in the southern part of the field. The RFT results provided essential pressure and fluid mobility data that, when integrated with petrophysical logs, enabled a more accurate estimation of effective porosity across the reservoir interval. The routine core analysis (RCA) yielded porosity values ranging from 20% to 32%, indicating a moderately to highly porous sandstone reservoir, characteristic of a high-quality clastic depositional system. These results were further supported by neutron-porosity logs and density-porosity logs acquired from the wells, which were used to generate a porosity range map for the field. The combination of log responses allowed for the identification of clean sand zones and differentiation from shaley intervals, thereby refining the reservoir quality model [27]. The porosity distribution was then upscaled and applied throughout the geological model using zonal and facies-based averaging techniques. This allowed the porosity trends observed at the well scale to be extrapolated laterally across the model grid, while maintaining geological consistency. The resulting porosity property could be visualized and validated in 3D, helping to identify sweet spots for drilling and injection, and informing volumetric estimates.The porosity plot which is up-scaled using the well log of neutron porosity has been shown in figure 5. It has different realizations run during up-scaling of the log petro-physically. It also shows the color legend for the distribution of the porosity, which ranges from 0 to 1 with increasing color legend from brown being 0 and dark red being 1.

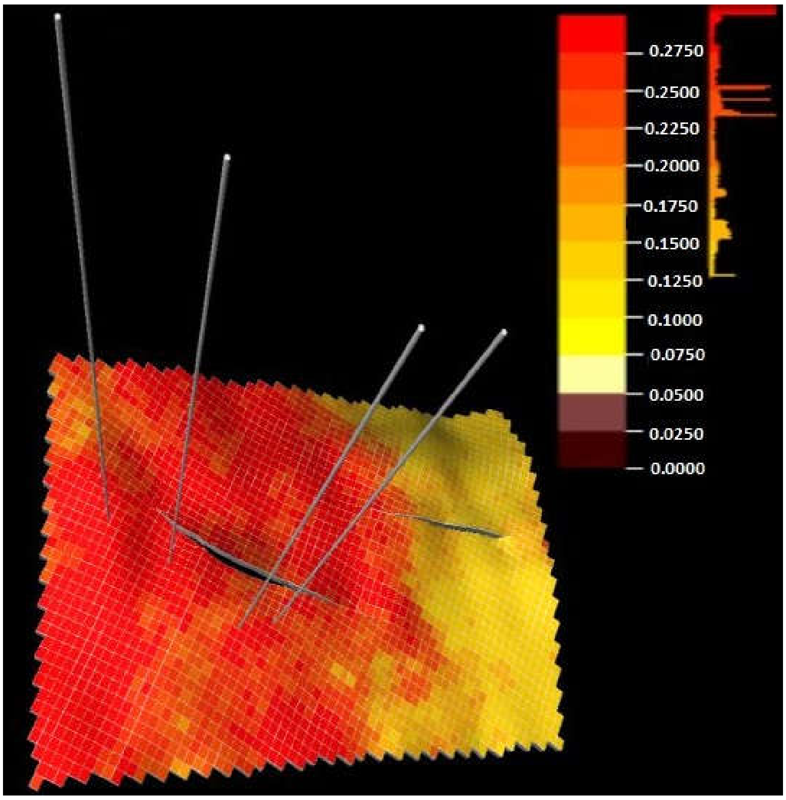

Figure 5: Porosity distribution

2.6.3 Permeability Predictions

The permeability property of the Penobscot reservoir model was developed using a combination of geometric modeling techniques and empirical correlations, specifically leveraging Timur's equation for permeability prediction. Initially, the base permeability distribution was generated through the property upscaling module of the geomodeling workflow, where core-derived measurements and log-based porosity estimates were integrated into the static grid [26]. In this model, permeability (i.e.; ease of fluid flow) was defined along two principal directions: permeability-i (horizontal) and permeability-k (vertical). The values were calculated separately, and an anisotropic ratio was applied based on reservoir fabric and depositional environment. Permeability-k was defined as 10% of permeability-i, a standard practice in layered clastic systems to reflect reduced vertical flow capacity due to sedimentary layering and compaction effects. Once the properties were calculated using the reservoir modeling software's calculator module, they were visualized in the 3D window for validation and quality control. The resulting spatial distributions of permeability-i and permeability-k are shown in Figure 6 and Figure 7, respectively.

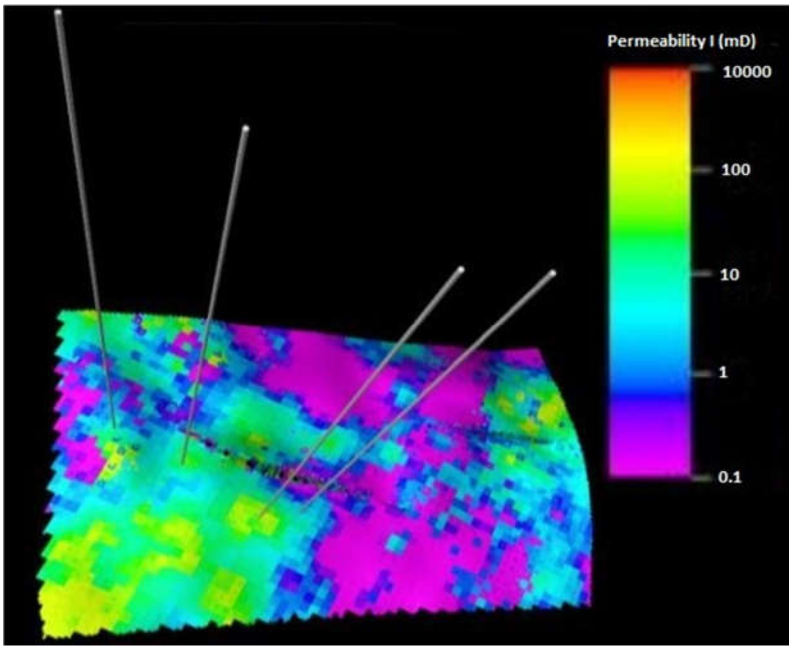

Figure 6: Permeability i

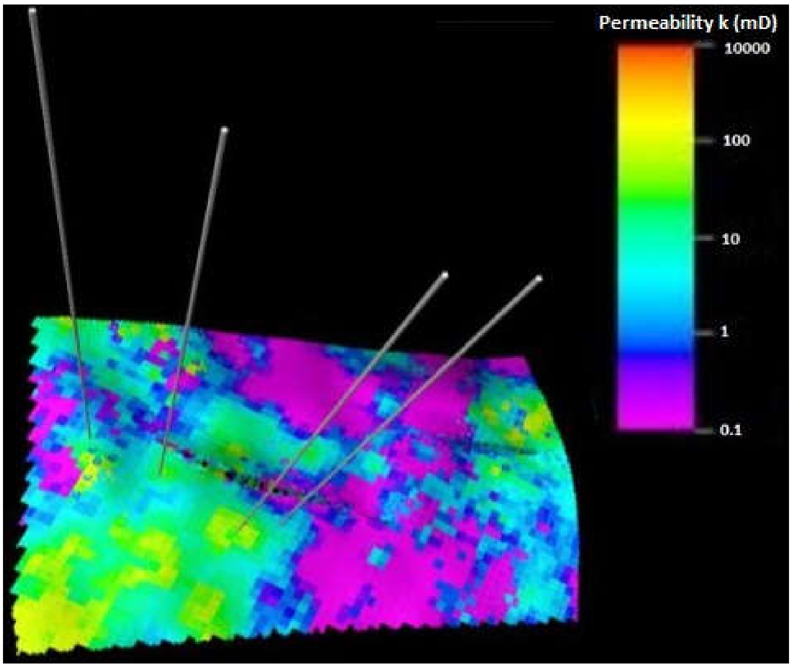

Figure 7: Permeability k

2.7 Simulation Procedure for Development Strategies

A field development strategy in reservoir engineering is a detailed, long-term plan that outlines how to efficiently and economically extract hydrocarbons from a reservoir. It encompasses decisions on the number and type of wells to drill (producers and injectors), their placement, drilling sequence, production rates, and whether enhanced recovery techniques such as water or gas injection will be applied. The strategy is determined through an integrated process that combines geological and reservoir modeling, historical production data, simulation studies, and economic evaluation. Engineers begin by constructing static and dynamic models of the reservoir, using data from seismic surveys, well logs, and core samples. Various production and injection scenarios are then simulated using tools like ECLIPSE to forecast fluid movement, pressure behavior, and recovery over time. These scenarios are analyzed and optimized through history matching, sensitivity studies, and, in some cases, machine learning algorithms to identify the most effective approach. Outputs from the development strategy include well schedules, production forecasts, pressure and saturation distributions, recovery factors, and cost estimates.

The development strategies represents the central element of this study, wherein the overall development plan of the field is defined. It involves defining the strategy for depleting or producing the reservoir. Key decisions made at this stage include determining the number of wells to be used for production and injection, as well as specifying the type of injection strategy to be employed. The production and injection schedules for each well such as; start and end dates are established based on the project's requirements. The Rules tab of the simulator is used to define operational constraints and limitations for individual wells or the entire field. It allows the setting of production or injection controls, including restrictions on the production of specific fluids. For injection wells, this may involve setting daily surface, reservoir, or well rates. In addition to rates and volumes, rules can be applied to control tubing head pressure and bottom-hole pressure, which are essential for managing drawdown either at the well or field level. Ultimately, this stage forms the foundation of the simulation process, establishing the framework for field development. It defines how the reservoir will be depleted or pressure-maintained, typically through water or gas injection at targeted locations, while coordinating production through various wells over designated periods.

After the development strategy is planned, the next step would be to define a simulation case on the previously made models of the reservoir. In defining the simulation case all the input properties are required to be included for the reservoir to deplete by using the different development strategies. Here, the very first decision required to be made is to identify which simulator to be used for simulating the model. In Petrel 2014, four distinct types of simulator models are available, each tailored to different reservoir simulation needs and complexities. The ECLIPSE 100 (E100) model is a traditional black-oil simulator, widely used for simulating oil, water, and gas phases in conventional reservoirs with relatively straightforward fluid behaviors. In contrast, ECLIPSE 300 (E300) is a compositional simulator, designed for more complex fluid systems. It models reservoir fluids using individual components, making it ideal for enhanced oil recovery (EOR) techniques, gas injection, and volatile oil reservoirs. FrontSim introduces a streamline-based approach to reservoir simulation. It emphasizes visualizing fluid flow paths efficiently and is often used for rapid history matching and evaluating waterflood performance, especially in heterogeneous reservoirs. Lastly, INTERSECT represents a next-generation, high-resolution simulator. It supports unstructured grids, advanced physical modeling (including thermal and geomechanics), and high-performance parallel computing. In this research, widely used ECLIPSE 100 (E100) model is prefered over the others for its simplicity and straight forward fluid behaviors representations. Once all the reservoir models, along with the rock and fluid properties have been input in the ECLIPSE 100 (E100), the simulation case is run generating results with different static, dynamic and pressure plots.

3. Results and Discussions

Once the simulation case has been run successfully, it would create results which can be used to plot graphs of different production parameters of different wells all together or one at a time. Also, it can be used to plot a graph of the entire field performance or of a group against a secondary identifier. The different secondary identifiers available for the results graph are cumulative production, production rates, injection rates, pressure and in place volume for each fluid phase. The recovery factor is also estimated, which is a key performance metric in reservoir engineering that indicates the percentage of hydrocarbons initially present in a reservoir that can be technically and economically recovered over the life of the field.

3.1 Development Strategy with Two Producing Wells (L-30 and B-41)

The first development strategy is using two existing exploratory wells by converting them to producing wells after completion and running them for a period of five years. As already mentioned in the coring analysis and the data provided it says that there were no significant shows of hydrocarbon from the well B-41. The well B-41 shows no producing worth its investment, which resulted in less cumulative production and very expensive project with no pay back within 5 years. The production profile of well L-30, B-41 and the whole field is shown in Figure. 8. The cumulative production of fluids and recovery factor obtained using this development strategy are as follows:

Cumulative Oil Produced: 1.752×10^6 m^3
Cumulative gas Produced: 3.954×10^9 m^3
Cumulative Water Produced: 4.669×10^4 m^3

Recovery Factor: 5.23%, in a cumulative production of 5 years.

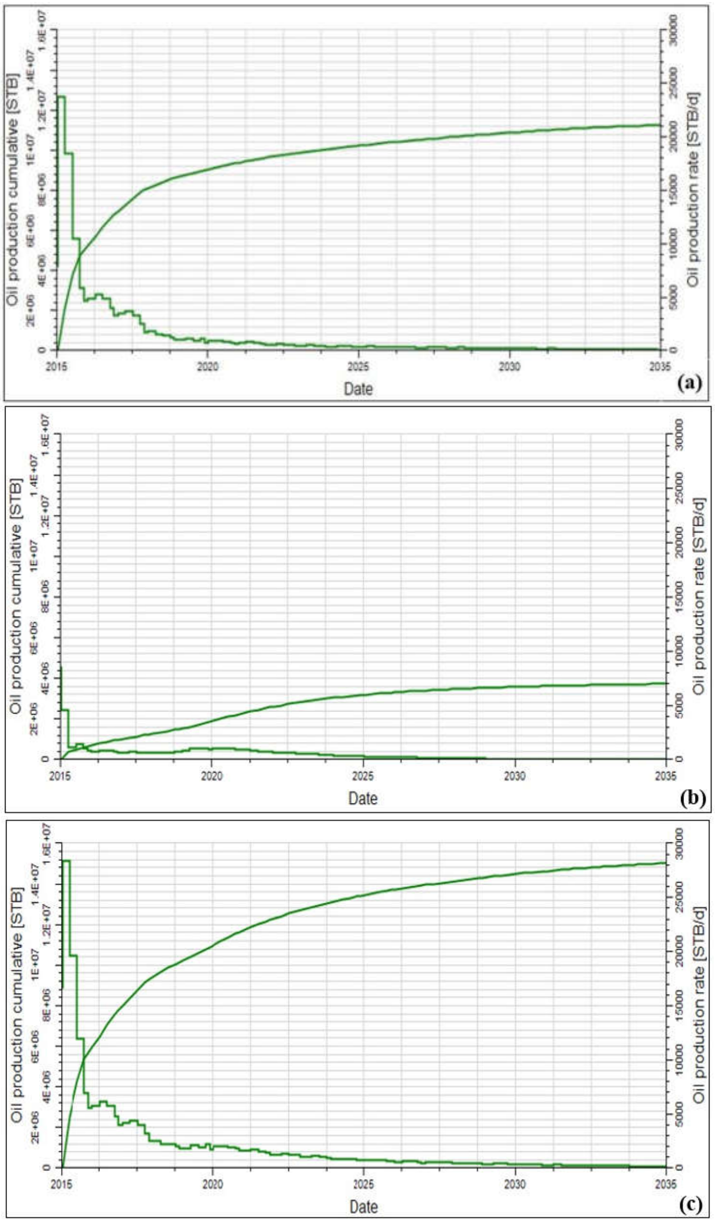

Figure 8: Oil production profiles of the development strategy with two producing wells. The cumulative oil production and oil production rate for (a) L-30, (b) B-41, and (c) Field observation.

3.2 Development Strategy with Two Producing wells and One Water Injection well

As seen in the previous strategy (3.1), well B-41 was not producing worth its investment of capital expindeture (CAPEX) and operational expindeture (OPEX), so it is decided to convert B-41 to an injection well as it had good reservoir connectivity which can be ascertained from the permeability plot. The other two producing wells were L-30 and a new well planned within the south Penobscot. The geo-coordinates for the new well (New well-1) are; x = 735199; y = 4894504. The water injection rate planned was 2000 m^3/day and the oil production rate was kept to a limit of 5000 m^3/day with a bottom hole pressure limitation kept to be 100 bar. It was observed that here the production resutls were slightly better than the first development strategy used. The production profile of the producing wells and the whole field is shown in Figure. 9. The cumulative production of fluids and recovery factor obtained using this development strategy are as follows:

Cumulative Oil produced: 1.324×10^3 m^3
Cumulative Gas Produced: 3.02×10^9 m^3
Cumulative Water Produced: 1.258×10^5 m^3
The recovery factor for oil was around 8.77%, in a cumulative production of 5 years.

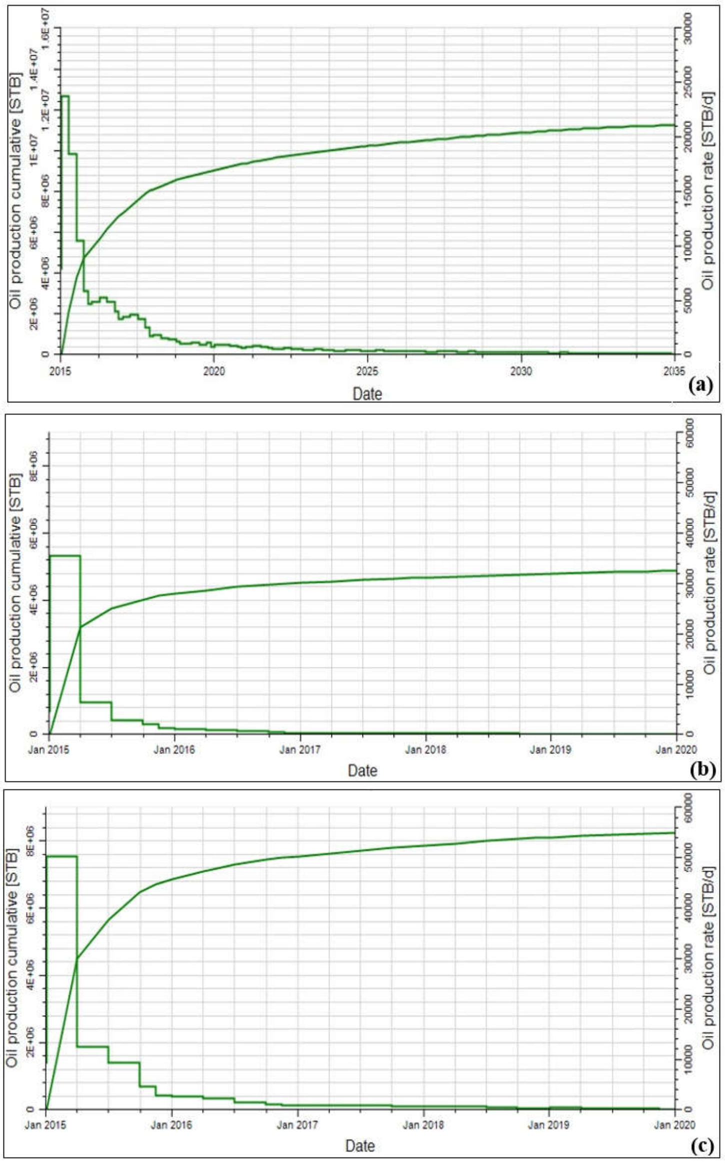

Figure 9: Oil production profiles of the development strategy with two producers and one injector. The cumulative oil production and oil production rate for (a) L-30, (b) New Well-1, and (c) Field observation.

3.3 Development Strategy with Three Producing Wells and One Water Injection Well

As seen in the former strategy, the cumulative production was better than the first strategy, but it didn't produce sufficient cumulative hydrocarbon to make the project economical over a period of time. So, it is decided to place another well in order to improve the cumulative production of the field. A new wells is planned considering sufficient oil saturation at each well based on the oil saturation plot. Also it is considered with respect to having a good connectivity with the water injection well in order to keep the bottom hole pressure well maintained by water injection at a higher rate. Additionally, the water production from the wells should also be limited as it makes the project costly as the water produced along with the oil needs processing which adds to another operational cost of the project. The new well drilled (New Well-2) had the following geo-coordinates; x =735152; y = 4896245. The cumulative production of fluids and recovery factor obtained using this development strategy are as follows:

Cumulative Oil Produced: 3.335×10^6 m^3
Cumulative gas Produced: 4.592×10^9 m^3
Cumulative water produced: 3.744×10^5 m^3
Recovery rate = 20.84%, in a cumulative production of 5 years.

The results for the production of wells are shown in the graph differently and also for the field on the cumulative basis as a consideration of all the wells together in Figure. 10 and Figure. 11.

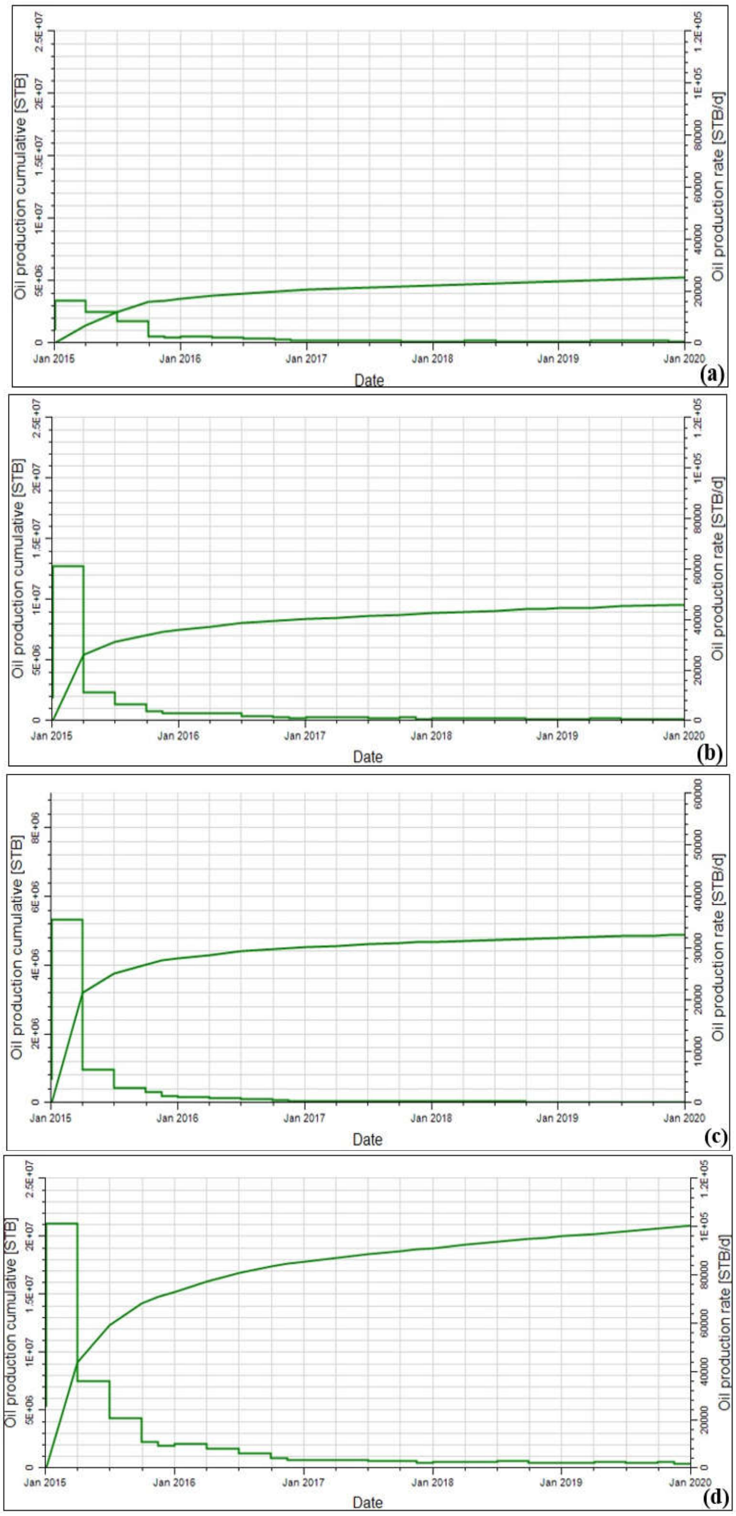

Figure 10: Oil production profiles of the development strategy with two producers and one injector. The cumulative oil production and oil production rate for (a) L-30, (b) New Well-1, (c) New Well-2, and (d) Field observation.

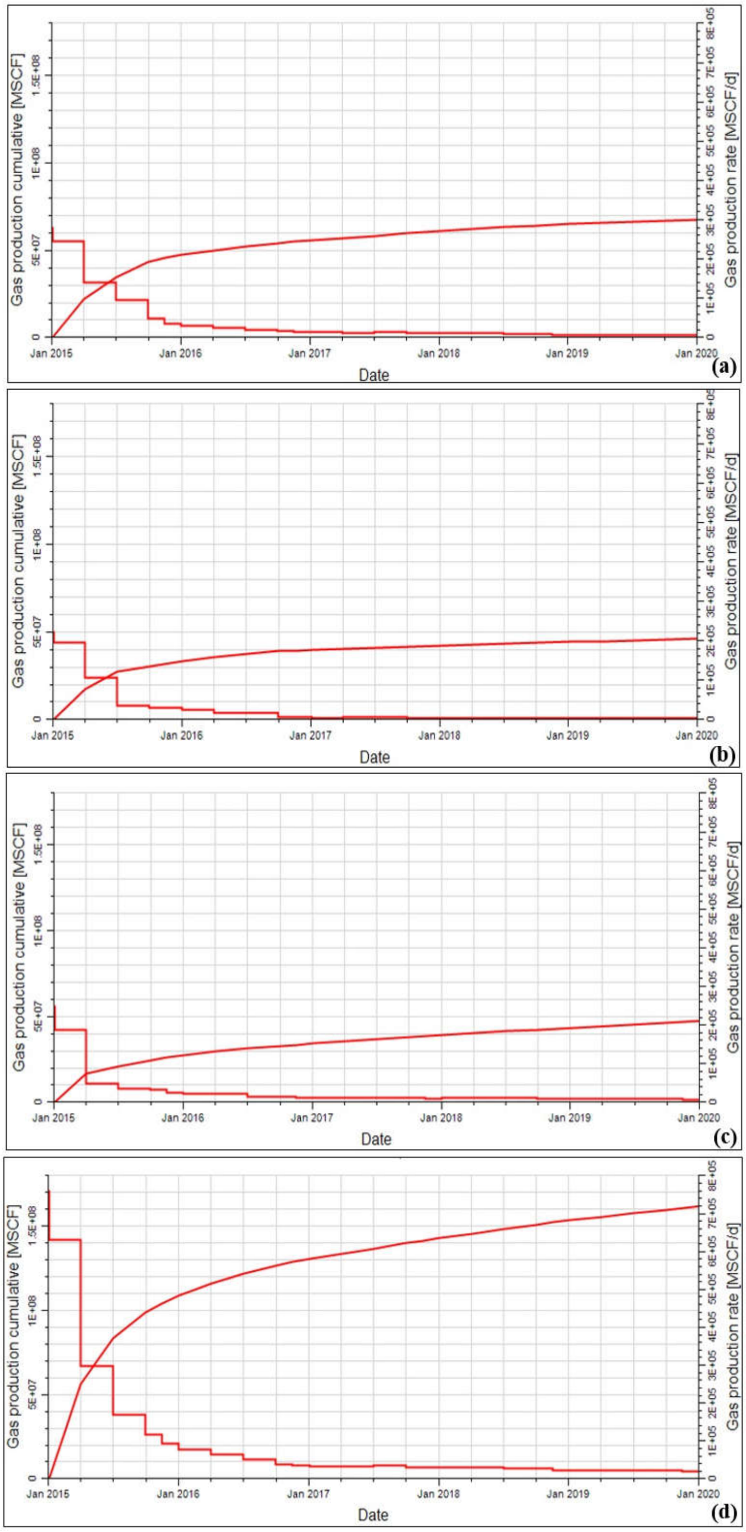

Figure 11: Gas production profiles of the development strategy with two producers and one injector. The cumulative gas production and gas production rate for (a) L-30, (b) New Well-1, (c) New Well-2, and (d) Field observation.

The results obtained from the proposed development strategy indicate strong performance in terms of cumulative oil and gas production. The use of three production wells and one injection well in the South Penobscot Field has proven to be effective, yielding favorable hydrocarbon recovery with a relatively low maximum water cut of 45%. The total fluid production is sufficiently high to be considered economically viable, as supported by the economic model assessments presented in subsequent sections of this study. Furthermore, both the cumulative liquid production and the daily liquid production rate remain within the operational limits of the Floating Production

Storage and Offloading (FPSO) unit. This ensures that no significant issues are anticipated with respect to storage capacity, export logistics, or pipeline transport to the shore.

4. Economics of the Project

Economic feasibility is a critical component in the overall success of any oil and gas project. High CAPEX and OPEX can significantly increase project costs and extend the payback period, thereby reducing the economic efficiency and attractiveness of the development. Therefore, incorporating a realistic and market-aligned economic assessment is essential in evaluating the viability and strategic approach of a project. In this study, a comprehensive economic model has been developed using current market data for oil and gas prices. The model incorporates probabilistic scenarios, including P10 (optimistic), P50 (base case), and P90 (conservative) price forecasts, to account for market volatility and uncertainty. It also integrates assumptions about future price trends, both positive and negative and considers potential variations in project performance due to technical uncertainties [28]. Figure. 12 shows the probabilistic oil price forecast scenario, showing P10 (optimistic), P50 (base case), and P90 (conservative) predictions from 2025 to 2034. The shaded region represents the uncertainty band, accounting for potential market fluctuations

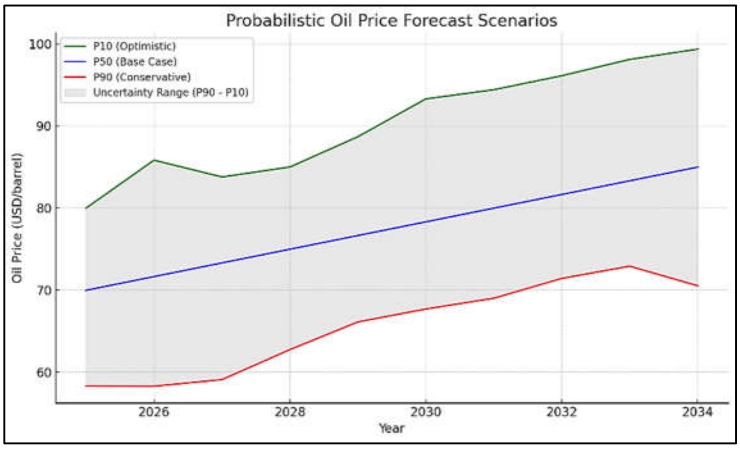

Figure 12: Probabilistic oil price forecast scenarios.

This approach ensures a more robust evaluation of project profitability under a range of possible future conditions.Table 4 shows all the calculations with consideration of the capital and operational expenditures throughout the life of the project. The calculations for the economic model of the project at different prices for the oil and gas prices with the base price of $50/ bbl for the oil and $2.7/ MScf. This economic model will be considering the royalty from the nova scotia government, federal taxes and the provincial taxes. Also, it shows with different realizations for the economic model with high and low crude prices. In the below economic analysis it's evident that the payback year is fourth year and the net pay after the taxes and royalty deductions in a cumulative of seven years itself is 61.78 million $. This can help in decision making for a company easier after analysing the economic considerations of the project including the CAPEX and OPEX. These operational expenditures consider water injection, producing wells and the exporting wells for the pipelines. While the capital expenditures consist of FPSO, well drilling cost, daily rig rate, completion cost, per year cost for pipeline and the well intervention cost. A step by step calculation is shown in the excel sheet. The years for the operations are also shown which shows that production starts in the third year as it takes time for drilling and appraisal time for the sanctioning of the project.

Table 4: Economic analysis of the project (in $ US)

Oil 10^6 bbl	Gas 10^3m^3	CAPEX	OPEX	Gross Revenue	Royalty	Net Revenue	Cost to be Recovered	Balance Recovered	Provincial Tax	Federal Tax	Profit
		8.5×10^6					8.50×10^6				
		4.4×10^7					5.25×10^7				
1.52×10^7	3.09×10^6	5.27×10^8	1.35×10^7	7.71×10^8	2.24×10^8	5.48×10^8	5.93×10^8	-4.53×10^7	-5.25×10^6	-6.16×10^6	-3.31×10^7
2.59×10^6	6.1×10^5	2×10^6	1.01×10^7	1.31×10^8	3.80×10^7	9.31×10^7	6.05×10^8	3.57×10^7	4.14×10^6	4.85×10^6	2.67×10^7
1.19×10^6	3.25×10^6	2×10^6	1.05×10^7	6.07×10^8	1.76×10^7	4.31×10^7	6.17×10^8	6.63×10^7	7.69×10^6	9.01×10^6	4.96×10^7
1.01 x 106	3.01×10^5	2×10^6	1.05×10^7	5.14×10^8	1.49×10^7	3.65×10^7	6.3×10^8	9.03×10^7	1.05×10^7	1.23×10^7	6.76×10^7
9.12×10^5	2.3×10^4	2×10^6	1.05×10^7	4.62×10^8	1.34×10^7	3.28×10^7	6.43×10^8	1.11×10^8	1.28×10^7	1.51×10^8	8.28×10^6

5. Conclusion and Recommendations

The primary objective of this study was to construct a realistic reservoir model using available geological, petrophysical, and fluid data derived from the exploratory wells. The model was calibrated to ensure that all rock and fluid properties are aligned with observed data, thus enabling a representative simulation of the reservoir's behavior. Following the successful model development, three experimental well plans were evaluated to identify an optimal field development strategy that maximizes hydrocarbon recovery while minimizing capital and operational expenditures. Economic evaluations were conducted in accordance with the fiscal and regulatory framework established by the Government of Nova Scotia. Among the strategies tested, the configuration comprising three production wells and one injection well emerged as the most effective one. Quantitative analysis indicates that this strategy yields the highest petroleum profit, amounting to approximately $82,784,897.20, surpassing the returns of other evaluated plans. Therefore, this development strategy not only demonstrates superior recovery performance but also exhibits strong economic viability. Given the anticipated global decline in accessible oil and gas resources amidst growing energy demand, the adoption of efficient and cost-effective field development strategies is imperative. The methodology and findings presented in this study offer a practical approach that can be adapted for the planning and execution of field development in other reservoirs worldwide considering their similarity in rock and fluid properties.

However, the reservoir model was developed using data derived solely from exploratory wells, which may not fully represent the heterogeneity and complexity of the entire reservoir. This reliance on limited data introduces uncertainty, particularly in unsampled regions. Additionally, the model assumes static geological and fluid properties over time, which may not capture the dynamic nature of reservoir conditions during production. The economic analysis, while robust, is based on the specific fiscal and regulatory framework of Nova Scotia, potentially limiting the broader applicability of the financial conclusions. Furthermore, only three development strategies were considered, which may not encompass the full spectrum of potentially optimal well configurations. The calibration of the model, although aligned with observed data, is inherently subject to uncertainties in the input parameters, such as porosity and permeability distributions. Yet, this study exemplifies the rational and strategic application of modern reservoir modeling and simulation software in the broader context of sustainable hydrocarbon resource management.

Future work on this study should consider dynamic updates to the reservoir model as new production data become available. This would allow for history matching and real-time model refinement, enabling more accurate forecasting and adaptive field management. Incorporating geo-mechanical and geochemical interactions could also provide a more holistic understanding of reservoir behavior, particularly in scenarios involving long-term injection or pressure depletion. On the simulation front, expanding the range of development strategies beyond the three tested in this study, such as staggered well patterns, horizontal or multilateral wells, or alternative injection schemes (e.g., water-alternating-gas, polymer flooding) may reveal even more economically or operationally favorable configurations. Additionally, optimization algorithms and machine learning techniques could be integrated to automate the evaluation of numerous development scenarios and identify near-optimal solutions efficiently.

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Competing Interests:

The authors declares no competing interests with any individual/organization anywhere.

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