International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /**https://doi.org/10.5281/zenodo.15127824** **ISSN 2488-8648**

Structural Uncertainty Analysis to Quantify Hydrocarbon Reserves, for "Nas" Reservoir, Onshore Niger Delta

[1]Odoga, A. and [2]Okujagu, D.C.

[1]Centre for Petroleum Geosciences, University of Port Harcourt
[2]Department of Geology, University of, Port Harcourt Choba, Port Harcourt State, Nigeria

Article Information

Article # 100251
Received: 17th Jan. 2025
Revision:18th Feb. 2025
2nd Revision: 15th Feb. 2025
Acceptance 26th March. 2025
Available online:
6rd April, 2025.

Key Words
Structural uncertainty,
Niger Delta,
Reservoir characterization,
Petrophysical analysis,
Hydrocarbon estimation.

Abstract

An increasingly common best practice in the prediction and communication of geology, detection and quantification of hydrocarbon accumulations is the use of 3D geologic models. This study quantified the structural uncertainty in hydrocarbon estimates in the "Nas reservoir", onshore Niger Delta. The study utilized 3D seismic, and well logs, to evaluate reservoir structural uncertainty in the low well density "Nas reservoir" with a view to identify and quantify the effects and implications of structural uncertainty the volume of hydrocarbon. This will then guide future well placements and refine business decisions on the investment for further wells in the reservoir. The well correlation of the field identified the reservoir tops and bases, that the reservoir is deposited in a transgressive episode of deposition and the average reservoir thickness along the correlation path is 91ftss (feet sub-sea).The reservoir structure is saddled with two highs confined in the form of four-way and fault-assisted closures. The Petrophysical analysis identified four distinct petrophysical zones and two major flow units' zone 1 and 2. Gas initially in place (GIIP) was estimated using NTG, Porosity, and Sw models. And the calculated GIIP is 67Bscf.Structural uncertainty analysis shows an uncertainty volume distribution with the low, mid and high GIIP as 67Bscf, 63Bscf, and 58Bscf respectively. GRV results from the structural uncertainty results in a high volume: 367,000 acres ft, Base volume: 349,00 acre.ft, and low volume:329,00acre.ft. The mid case volume represents a 6% increase from the low while the high case represents a 5% increase from the mid.It is recommended that structural uncertainty be run in fields with low well density to quantify GRV uncertainty. This will always serve to enrich data for further decision-making. "Nas reservoir" management can employ these results to make informed decisions on its development

***Corresponding Author:** Okujagu, D.C..; diepiriye.okujagu@uniport.edu.ng

Introduction

There is extensive usage of three-dimensional geological models in geology, geological forecasting, reporting, and the search for and evaluation of hydrocarbon reserves. Wellmann and Caumon (2018) state that experts in various disciplines, including the oil industry, have come to the realised that no one model can encompass all the knowledge regarding inherent risks. This realisation has dawned on all of these professionals. For this reason, it is common practice to evaluate the shortcomings of geological models using a variety of realisation techniques (Pakyuz-Charrier *et al*., 2018a, 2018b). Since the first oil crisis, the petroleum industry has significantly increased the amount of time spent assessing risk and uncertainty. The quantity of hydrocarbons that may be recovered is affected by these unknowns, which can originate from several sources and alter the pool's physical composition. The reliability of reservoir models is impacted by the degree of structural uncertainty. This holds for models that are both static and in motion. Uncertainty stems mostly from structural ambiguity in the oil output field. The distribution of reserve qualities, the amount in the ground, and the operation of dynamic simulations are all difficult to acquire a good picture of, making measurement and evaluation difficult. Several cases have undergone exhaustive investigations into all conceivable geological scenarios that are compatible with the interpreted evidence. Schmeeberger *et al*., (2017) state that this demonstrates how uncertainty has consistently impacted decisions for future field development. This occurs due to insufficient time and unclear instructions.

The structural geology of an oil field is a large-scale property exhibiting non-linear flow behaviour. Accordingly, assessment of the initialize uncertainty of future production from a reservoir should frequently involve the generation of multiple structural models to reflect the elements of this uncertainty, and all the models generated should be consistent with the available data. Even though they are relatively simple models, hand drawing so many structural models may take a lot of time

and prove very expensive. This is especially so where the seismic data is poor or where a large number of sub-seismic faults with significant flow impacts are anticipated. Consequently, it is necessary that we must have tools for simulating structural features using automation. These tools should provide outputs that should be inputted into the flow simulation model for additional examination of the effects of structural uncertainty on oil rates and total production.
Structural risks/uncertainties influence exploration, development and production and also have impacts on drilling decisions (Pakyuz-charrier *et al*., 2019). This paper notes that flaws exist within geologic models and specifically looks at why flaws are significant in such models. The primary inputs by which the spatial locations of faults are assessed are migrated seismic images. Velocity errors in the overburden can migrate a fault of interest and distort its observed seismic image location. Knowledge of fault uncertainty is particularly important because it has consequences for the current and desired well path, alters the volumes or development program, and, in general, well cost. For effective reservoir management, there is a need to have a reliable approach to the use of available reservoir knowledge and uncertainty. General characteristics of the reservoir, changes in petrophysical parameters, and positions of the oil-water contact and gas-oil contacts are the major factors of uncertainty. Random measurement errors, data sampling rate, systematic errors due to geological and seismic heterogeneities, migration errors, non-uniqueness, errors from human interpreters, and positional errors from well correlation are a few sources of spatial uncertainty in seismic data interpretation. Structural uncertainty has a large, and sometimes dominating, influence on the variance of a reservoir's production because inhomogeneities have a large effect on flow.
Various Differences are present within the subsurface as a consequence of different geological formations. How the properties are arranged spatially in the subsurface is particularly critical in the process of exploration and development of hydrocarbon as observed by Culshaw (2005), this is in light of the structure of the reservoir and field which formally describes a large-scale structure of the sub-surface. As the reserves of hydrocarbon have dwindled and competition has emerged within the oil industry the requirement to decrease costs by drilling fewer wells deciding whether to drill horizontal or vertical wells, the actual implementation of the activity, the optimization of production and anticipating the dynamics of low relief structural closures, has emphasized the need to understand the effects of issues such as faults and fractures on fluid flow. The measure of model quality to the end user exploited by Turner and Gable (2007) and Stamm *et al*. (2019) means that qualitative assessment of uncertainties inherent in a given 3D geologic model, especially where the number of wells is limited, can be helpful. This understanding also helps the geologist during model creation by assessing the quality of the input data and identifying the effects of bias acquired before input as well as interpretations (Bond, 2015; Jessell *et al.*, 2018). Consequently, it has become most important to assess behaviours and distribution of fluids regarding to faults and fractures in hydrocarbon provinces. In sandstone reservoirs modern enhancements in quantifying the impact of faults in controlling the flow capability of reservoirs have enhanced improved reservoir simulation models. Indeed, nearly all hydrocarbon geologists have asked themselves the question "What is the behaviour of this particular fault?". At some point. In other words, what is the geometry of these fault zones, what do the fault rocks that may have formed look like, and where are they found at depth? Another question is 'What could be the fault zone's influence on fluid flow with time?'. To address some of the above questions and, therefore, improve the understanding of the structural uncertainty affecting the determination of Nas reservoir's hydrocarbon reserves, this study plans to proceed.

Location of the Study Area
The Nas reservoir is located within latitude 4^0 55"& 5^0 10" N and longitude 6^0 50"& 7^0 10"E at the central depobelt of the Niger Delta, about 110 km west of Port Harcourt. (Figure 1)

Geology of the Niger Delta
Sediment loading can lead to the structural collapse of the continental margin; the Niger Delta basin on Africa's western African coast is a well-known example of this (Armitage 2012, Rensbergen and Morley 2000; Edwards 2000). Situated in the Gulf of Guinea, the Niger Delta extends approximately 7,500 square kilometres. A silt mound, as described by Bustin in 1988, can reach a height of up to 12,000 meters. Those in the know and those who share this view believe that the current delta formed by the drainage systems of the Niger and Benue rivers occupies a substantially lesser space than the basin fill. The Niger Delta is comprised of depressions that extend from the oceanic subduction zone to the continental boundary. According to Fazli-Khani and Back (2012), regressive sequences spanning the Eocene to the Present Day are comprised within this division. The gradual formation of the Delta is demonstrated by the shoreline's movement towards the basin from the Eocene to the present day. Ajesafe and Ako (2013) characterised the reservoir granite in the Y Field in the Niger Delta basins using petrophysical and quantitative seismic characteristics. We put this in place so everyone could see the big picture. They finally settled on the idea that reservoir rocks' characteristics can be reliably predicted using seismic attributes. The evaluation and description of a reservoir can be accomplished through the combined use of structural interpretation and attribute analysis. The Agbada Formation's interbedded shale is the dominant seal rock type in the Niger Delta, as stated by Doust and Omatsola (1990). The shale, according to Dust and Omatsola (1990), differs from reservoir sands because of faulting, which causes vertical seals and clay layers to form along faults and creates interbedded sealing units. Heavy erosion during the early to middle Miocene epoch developed canyons

International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /**https://doi.org/10.5281/zenodo.15127824** **ISSN 2488-8648**

packed with clay on the delta's banks. These clays are used as top seals to protect some of the most vital offshore oilfields in the world. Colleagues of Aanuoluwa proposed investigating the defects that lead to hydrocarbon accumulation in a trap as a means to guarantee that field volumetric studies yield valuable intelligence. The utilisation of trap analysis helped alleviate uncertainty around the discovery and extraction of hydrocarbons in one particular area. These defects may serve as a crack that fluids can squeeze through. He remained with his companions. To mitigate the risks associated with hydrocarbon quantification, additional structural research was conducted at a site in the onshore Niger Delta in 2017. Hydrocarbon exploration and production depend on understanding the intricate fissures that exist beneath the surface. The fault significantly impacts the processes of hydrocarbon capture and separation during transportation, which causes this to occur. The flow of hydrocarbons is intimately related to faults. Geometrical defects in hydrocarbon deposits both impede and enable fluid movement. The arithmetic becomes considerably more intricate because of this.

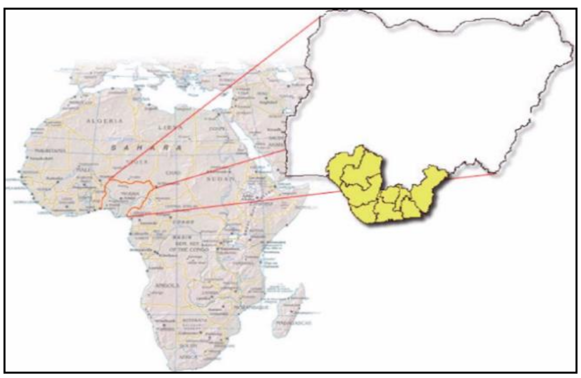


Figure 1: Map of Africa and Nigeria showing the Niger Delta Region of Nigeria

Creating Value from Uncertainty
Approaches to Uncertainty

The area's capacity to generate revenue is highly dependent on removing the uncertainties associated with ponds. To build and manage a field, it is necessary to get fundamental data from a reservoir. In this content, you could find data and measurements. The objective is to minimize expenditure while ensuring that the area in question is well-managed and has adequate room for expansion. What the hazy circumstance was that prompted a change in development plans for the area is clarified. Bratvold and Begg state that this is the primary justification for assessing uncertainty, as it highlights the significance of making a different decision to enhance the project's value. Investing in field development and operations early on is likely to be the most risky element. Figure 10 illustrates the significance of decision-making during the funding phases of field development projects in reducing the uncertainty that is inherent to these endeavours. During the exploratory phase, there is a great deal of uncertainty because seismic data is not always readily available. A variety of supplementary data sources will be utilised to bring uncertainty down to a reasonable level for field development assessments. These include appraisal drilling, well logging, well testing, studies of reservoir modelling, pricing analysis, and more (Simpson *et al.*, 2000). Thus, a significant portion of the decision has already been taken, although numerous uncertainties remain regarding the reservoir's future behaviour and production. There is a great deal of uncertainty surrounding this throughout the field development period.

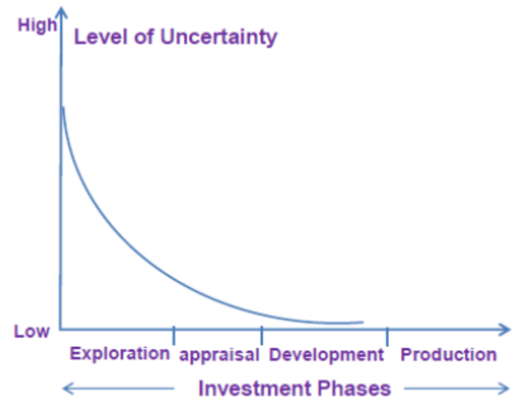


Figure 2: Level of uncertainty related to decision-making development during the investment phases (Behrenbruch, 2014).

In projects where decisions are required, there are several possibilities regarding the handling of uncertainty. The following are common approaches:

1. Ignore uncertainty.
2. Reduce uncertainty by gathering information.
3. Develop a flexible response to uncertainty.

Energy companies have a history of denying the possibility of problems occurring. According to Ringrose and Bentley (2015), reservoir modelling is frequently employed to conceal rather than reveal uncertainties. If we follow this strategy, our efforts will not provide the maximum value that can be achieved (Bratvold and Begg, 2010).

The second approach is to gather as much information as possible to minimize uncertainty. People may be able to use this information to make more informed judgements. Here is a rundown of the top methods for reducing uncertainty through data collection: Logging surveys, Appraisal drilling, Core samples, Seismic study, and Well test analyses

Reservoir simulation studies (e.g. history matching); Analyze trends in similar fields; Implement new technology to "old" fields

Despite their primary objective of reducing the economic risks associated with expansion, the aforementioned studies and testing do cost money. Reducing uncertainty can't be the ultimate aim, thus quantifying it shouldn't be considered

International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /https://doi.org/10.5281/zenodo.15127824 ISSN 2488-8648

a goal in and of itself. In 2007, Bickel and Bratvold proposed that appraising a development should be the primary objective of usage. To make informed decisions regarding the expansion and functioning of the sector, uncertainties must be controlled and studied. One such approach is the Value-of-Information (VoI) method. The value of acquiring knowledge is evaluated using this method of checking. They develop into a trustworthy and transparent metric for decision-making over time (Demirmen, 2001).

It concerns the ability to develop a form of dynamic response to the inherent uncertainty; as we mentioned earlier and all the "downsides" of it could be lessened with this freeze. In the same manner, it can also afford a positive of uncertainty by getting an upside. The flexibility of a field can be in the form of following:

Prepare room for extra injection wells in a case where the field needs extra pressure support.

Make room for extra production wells in case the reserves are higher than expected or a well becomes damaged.

Arrange facilities suited for higher production rates.

Use equipment with possibilities for modifications to meet changes in the production, which gives room for flexibility. Consequently, operational flexibility is intended to mitigate risk or to exploit a chance. Still, to decide whether the flexibility costs are rational, a two-step examination can be done known as the Value-of-Flexibility, VoF.

Structural Uncertainty in Niger Delta

The uncertainty is heightened by the knowledge that we can never know with certainty what the future holds. Hydrocarbon reserves, recovery timeframes, and current practices are topics of great interest to many. The impact on economic outcomes of these highly sensitive characteristics is substantial. When deciding on the stages of reservoir growth, these figures are crucial for oil producers and investors. From exploratory drilling to commercial extraction, there is always the chance of something bad happening in the oil and gas industry. This entails collecting seismic data, analysing it, deducing its meaning, and drilling. The creative process is fraught with danger at every turn. However, it is insufficient to merely evaluate potential dangers. Doing uncertainty analysis is essential for learning about all the anticipated benefits of extracting any hydrocarbon energy source. Mistakes in planning and measurement are common when individuals lack a thorough understanding of various geological and geophysical aspects. The Maze method includes the following steps: interpreting and analysing seismic data and log data; developing geological conceptual models; creating a three-dimensional reservoir model; and accurately estimating fluid connections and kinds. All of these processes occur during a subsurface investigation when a geological model is being constructed. It has already been mentioned that there are hazards associated with data use, data selection, and data interpretation, in addition to the risks associated with each process individually. It is critical to consider all the unknowns in the value chain in order to accurately estimate volume. Errors in structural design can take several forms, including fault seals and ambiguity in structural models. There is ambiguity when you acknowledge your shortcomings. Defining duties while allowing for uncertainty Reliability and clarity issues Bo and Bg classify the uncertainty as either structural, involving fluid interaction, petrophysical, or PVT.

The velocities model, the time interpretation decision, the isochore thickness, and the fault interpretation all cast doubt on the structure's depth. Once modified, these are re-added to the structural depth map with the labels well-seismic miss-tie, horizon miss-pick, and fault misrepresentation. Measuring permeability, water saturation, porosity, and NTG can lead to petrophysical mistakes. To determine the porosity, the typical porosities observed across the reservoir's thickness are employed. When it comes to porosity uncertainty, there are two primary kinds of data. The measurement, processing, and interpretation of the logging devices is the primary source of the problem. Well monitoring is the subject of the second issue. There is no structure or connection between the orientations that determine the trends in internal porosity; what matters is the direction they are facing. This is why easily line measurements are so crucial. Because it raises questions about the amount of water present and how easy it can move through, the problem is analogous to the uncertainty around porosity. Finding the input parameter for petrophysical parameters using empirical models is fraught with uncertainty. Due to the lack of uncertainty surrounding the expansion factors Bo and Bg, the primary cause of error was likely the laboratory experiments. Because fluid samples aren't always available, there's a lot of guesswork when working with fluids in the field. Looking at data from individual wells and comparing the field-wide changes in the "contaminant" attributes allows us to determine this variability. Several methods exist for estimating the degree of uncertainty and risk associated with each step of the petroleum production process. Such approaches are known as uncertainty analysis methods. Random methods and deterministic approaches are the two most common ways to evaluate uncertainty. To determine the degree of uncertainty regarding the present, the deterministic technique makes use of previously observed observations of the future. Conversely, the stochastic technique incorporates a multitude of arbitrary measures, referred to as "realisations," that are constrained to specific upper and lower bounds.

Reservoir Heterogeneity

The term "heterogeneity" refers to the degree to which the characteristics of a reservoir vary throughout both space and time. Potentially, the shifting location inside the reservoir is responsible for these changes in geological properties. A variety of reservoir sizes are at your disposal. The amount of heterogeneity, however, varies greatly among reservoirs. Homogenous pools are easily

International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /**https://doi.org/10.5281/zenodo.15127824** **ISSN 2488-8648**

recognisable. You can describe the entire reservoir area, regardless of its location, using a measurable property of the reservoir. Although the reservoir is becoming more diversified, it is also becoming more complex. The location determines the features of the reservoir. A comprehensive understanding of a heterogeneous reservoir requires a geographical forecast of the changes in rock facies, porosity, permeability, saturation, and fractures (Kelkar 2002). A numerical representation of the rock and fluid properties must be assigned to each of the one million grid block cells utilised to construct the simulation models. Using identical values for each attribute across all grid blocks is one technique to obtain the values for the rock and fluid features in the simulation model. Assuming the pool is homogeneous is the foundation of this approach. Incorrect and unrealistically optimistic findings will be produced by a simulation model that disregards the reservoir's geology. Conversely, property values for grid cells can be generated through a random number generator. Not only that, but this model disregards the basins' geological characteristics and the fact that data from close by places often shows similarities and data from farther away shows disparities. In the absence of direct measurements from the reservoir, geostatistics facilitates the estimation of reservoir properties. The concept of regionalised variables was proposed by Georges Matheron at Fontainebleau. The discipline that applies this theory to data pattern discovery is geostatistics. The fundamental distinction between geostatistics and conventional statistics is that the former deals with spatiallylinked random data and the latter with independent, uncorrelated data. Finding and handling the many ways in which disparities manifest might help reduce the confusion that these figures generate. Whether it's the variations in pores or the primary storage units in a field, heterogeneity is present at every level. The efficiency of a resource and the amount of oil that can be extracted are both affected by several kinds of heterogeneities. The significance of heterogeneity scales is demonstrated here. To achieve optimal output, it is critical to accurately detect and comprehend the reservoir's heterogeneities at various capacities. We employ four distinct complexity levels to identify the stages of heterogeneity.

Microscopic Heterogeneities*:* Deciding how many minute variations there are at the micro level is crucial. You really must have this. Observing rocks and their characteristics using a microscope allows one to quantify features such as the form and dimensions of porous plates, the surface of the rock, the packing structure, the roughness of pore walls, the quantity of clay covering pore throats, and the location and size of grain apertures and throats. The key factors that slow down events are the processes of putting down particles and compacting, solidifying, and dissolving them. Oil can accumulate in pores that aren't uniform in size and shape since fluids tend to flow in certain directions. When the displacement process fails, it leaves behind a large amount of residue or trapped hydrocarbon. The amount of oil that can be recovered determines the exact proportion in which this will occur.

Macroscopic Heterogeneity: finds the most fundamental level of the body. Extensive experimental core investigation examines the water-holding capacity, saturation, porosity, permeability, and capillary pressure of the rock. The rock and fluid variables that power large-scale reservoir simulation models are determined via logs and well tests. To guarantee the accuracy of the data, this is carried out. Thus, the shape and power of the displaced fluids' flood front, as well as the amounts of oil being skipped, are affected by the presence of heterogeneities on a macroscale.

Megascopic Heterogeneity*:* The inquiry is based on the standard practice of using reservoir simulation to test flow units. The following are a few instances of megascopic heterogeneities: Layers that undulate and overlap; large lithological changes within the reservoir; fluid boundaries within the reservoir; vertical and lateral production capabilities of the reservoir; and the ability of the components to communicate and flow freely. Controlling the reservoir becomes very crucial at this spacing of wells. Well logging and correlations, transient pressure analysis, tracer studies, and high-resolution seismic imaging are some of the ways that these variations might be discovered. The stratification of the initial reservoir unit and natural permeability trends are two possible explanations for the observed variations in well-to-well recovery; this method allows us to determine the nature of these discrepancies. Reservoir engineering models frequently incorporate the idea of layering due to its recognition as a significant form of heterogeneity. The majority of reservoirs consist of strata containing various minerals with potential for extraction. You can connect or split these layers as you like. These levels could be interconnected or independent. Plus, these layers could be thick yet still allow a lot of things through. If you want to know what each level of EOR is like and keep track of all the different duties, you might require this type of description. This suggests that heterogeneities on a macro-scale may have their origins in micro-scale variations. On the larger reservoir, nevertheless, their impact will be identical to that of macro-scale heterogeneities.

Areal heterogeneities*:* Thus, the vertical heterogeneities alter the vertical sweep's efficacy and the aerial heterogeneities alter the aerial sweep's efficacy. Reservoir heterogeneities can cause large- and small-scale feature changes along and throughout the reservoir's length and width. This allows the transferred fluids to bypass the reservoir and reach the producing well. They may part with a lot of oil, which is known as AGO (see associated crude). All of the field is included in the vast array of differences. This phase of exploration involves the identification and mapping of reserves. Following the description of the inter-well space, the field size is now added. The formation of

April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /**https://doi.org/10.5281/zenodo.15127824** **ISSN 2488-8648**

reservoirs or their evolution throughout time as a result of tectonic processes can explain the variety of reservoir designs seen in different fields. No portion of the oil source may be accessed since variations in reserves cannot be observed or quantified on a gigascale. Improving the efficiency of oil and gas production in reservoirs and making better field development plans are both made possible by including heterogeneity in reservoir modelling models. This makes it easier to access trapped or remaining hydrocarbon resources. Given the abundance of cited sources, this is undeniable. The amount of information we have about the reservoirs determines how unique they are. However, one crucial consideration is the ease of data retrieval from reservoirs.

Sources of Uncertainty

Finding out the truth about the reservoir is not the role of reservoir engineers. The goal instead should be to create a reasonable model that can foretell the reservoir's future performance based on all the data that is currently available. Finding the recovery method that most accurately forecasts hydrocarbon inventories and production rates is the study's primary objective. Reservoir studies include the analysis of a wide variety of data types, including geological, seismic, petrophysical, well, and production records. While the static data do reveal the characteristics of the fluids at well locations and the shapes of the reservoirs, they do not reveal the fluids'behaviour during production. The dynamic storage data, on the other hand, reveals the material's movement throughout production. Here is a list of categories and the parts that go along with them that explain the many forms of doubt about these facts.

Uncertainty Due To Petrophysical Data

The primary locations for collecting reservoir data are at well sites within reservoirs. An exemption was made for outcrop data and 2-D and 3-D seismic data. In mature, well-established fields, the reservoir percentage at these well sites is less than 1%. The data from the reservoirs is difficult to grasp, particularly in areas that aren't on the wells, because most reservoirs are extremely different from each other. The degree of uncertainty could vary for each variable due to several reasons. One possible explanation for this shift is that determining the value of a number, particularly one that is difficult to quantify, is not always straightforward. There are serveral points in the reservoir where physical properties can only be determined by sampling; this could lead to inaccurate results due to fluids in the borehole or the fact that rock and fluids can undergo change when subjected to laboratory heat and pressure (Walstrom, 1967).

Uncertainty in Geophysical Data

Collecting, processing, and analyzing seismic data is not without its risks in geophysics. The following uncertainties were identified by Sandsdalen et al. in 1996:

i. Uncertainties and errors in picking horizons
ii. The difference between several interpretations
iii. Uncertainties and errors in depth conversion
iv. Uncertainties in seismic-to-well-tie
v. Uncertainties in pre-processing and migration
vi. Uncertainties in the amplitude map of the top reservoir

Uncertainty Due to Geological Data

Many things remain a mystery in geology, such as the field's theoretical foundations, the characteristics of reservoirs, their sizes, and the characteristics of the rock that makes up reservoirs (Corre, 2000). Regardless, there are a lot of moving pieces in any geological model due to the scarcity of well data and the difficulty in quantifying the impact of geophysical features on reservoir size variations. The following are examples of geologically-related unknowns:

i. Uncertainties in gross rock volume
ii. Uncertainties in the extension and orientation of sedimentary bodies
iii. Uncertainties in the distribution, shape, and limits of reservoir rock types
iv. Uncertainties in the porosity values and their distribution
v. Uncertainties in the horizontal permeability values and their distribution
vi. Uncertainties in the layers Net-to-Gross Ratio
vii. Uncertainties in the reservoir fluids contacts

Uncertainty Due to Dynamic Reservoir Data

The output zone is vulnerable to any changes to the reservoir flow. Factors such as well integrity, thermodynamic characteristics, fault transmissibilities, extra horizontal barriers, levels of horizontal and vertical barriers, and the ratio of vertical to horizontal permeability are components of these considerations.

Uncertainty of Reservoir Fluids Data

To process oil and gas and develop field transport and marketing strategies, accurate descriptions of reservoir fluids and characteristics are crucial (Meisingset, 1999). Who or what these storing fluids are remains unclear:

i. Uncertainty in reservoir fluid samples which arises due to a lack of representative samples from the reservoir.
ii. Uncertainty in reservoir samples from different reservoir zones. Possible variations in fluid properties in different parts of the field may introduce uncertainty in the reservoir fluid’s description
iii. Uncertainty in the compositional analyses
iv. Uncertainty in volumetric measurements in the PVT laboratory. This is considered to be of less importance compared with having representative fluid samples
v. Uncertainties in the reservoir fluids’ interfacial tension. This may be of importance due to its effect on the capillary pressure, and/or compositional effects like re-vaporization of oil into injection gas (Meisingset, 1999).

International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /**https://doi.org/10.5281/zenodo.15127824** **ISSN 2488-8648**

Uncertainties in Reservoir Parameters: Key Uncertainties in Reservoir Parameters

Although Ma (2011) claimed a reservoir was clear a long time ago, there is little evidence to support this claim. The only remaining question is how the reserve should be defined. Due to uncertainty, the description of the reservoir lacks sufficient detail.The geological matrix underwent several mechanical and chemical changes throughout the burial phase. Only at this point can the composition of the actual reservoir be determined. This followed the previous use of geomorphological techniques to construct a reservoir. The degree of complexity of a reservoir deposit is affected by numerous factors. Primordial factors include its formation environment and internal alterations brought about by subsurface intraformational and inter-frost interactions. Due to issues with scale, measurement errors, and a lack of information, it is not possible to determine the type of reservoir it is. Many components of a reservoir do not correspond to one another due to the reservoir's complexity. Accurate measurements of this variance are notoriously difficult to come by, and local measurements can occasionally provide misleading results. In this section, we will provide a brief overview of the typical method for gathering crucial parameter data, along with the associated inaccuracy. The reservoir is constructed by employing the structural trap and fluid linkages. These two features indicate the location of the pond's edge. Seismic data and measurements reveal that the structure is made up of faults and surfaces. Seismic investigations of today can determine porosity rates and reveal the various rock types present in a given location. These surveys were conducted just a short time ago. However, about the dangers of earthquakes, Ringrose and Bentley (2015) state: Although seismic activity poses numerous dangers, it is not always easy to tell the truth from seismic measurements and reflections since certain fissures within and around a structure are not easily visible. This is because incorrect assumptions could be triggered if these errors were to encourage others to believe in the seismic event, Faults tend to be missing in areas of poor seismic quality, Seismic noise makes it difficult to identify fault intersections, Faults may be interpreted on seismic noise, Horizon interpretations may be extended down fault planes.

Internal layering and variation are likely to be visible in the structure due to the presence of continuous facies and lithologies. It is possible that this kind of bacterial reduction would provide clues about the reservoir deposit's environment, which would be useful for identifying patterns in the rock layers. Continuing the process until the measurement is taken will allow for the collection of numerous valuable sources of information regarding the reservoir factors. One can learn about the rock and the object under observation in two ways: directly and indirectly. Lab tests performed on reservoir core samples constitute primary measurements. Geophysical logs, seismic mapping, and well tests are some examples of methods that fall under the category of indirect measures. From extremely tiny regions linked to nuclei to extremely huge regions impacted by earthquakes, the measurements are taken on a wide range of scales. Very few sources provide data on the characteristics near the reservoir measuring site. Logs, core samples, and well tests are all part of this. It follows that specific locations inside the reservoir, such as the locations of the oil wells, should be able to be tested for specific properties, including porosity, permeability, net-to-gross, and PVT. To identify patterns in well and seismic data, interpolative perspectives will be required. This could be useful in another context. To provide a comprehensive description of the reservoir, other characteristics must be presented. The term "upscaling" refers to the process of estimating a parameter's value at a larger scale using smaller-scale observations or data. It is possible that upscaling is the primary cause of uncertainty when describing the reservoir, as amounts are given to spaces that have not been tested within the reservoir.

Since the cores themselves are a part of the reservoir, they provide a useful proxy for the reservoir's hydrodynamic and geological characteristics when conducting core analysis. Typically, fluid characteristics are examined during laboratory experiments. The characteristics of the fluid are being precisely described by some new methodologies and applications. The estimations will still be off due to issues with the lab tests. When considering uncertainties in fluid characteristics, the Lee-Gonzales gas viscosity correlation—which is commonly utilized by PVT labs—can be inaccurate by as much as 20% for rich gas condensates (Whitson and Brulé 2000). Skogen (2014) argues that the primary issue with core analysis, particularly with rock properties, is the fact that these parameters can only be assessed locally, and any attempt to scale them up introduces a significant amount of error. This is a common occurrence when the circumstances are examined. You can't find out anything about the local rock formations from core samples. Core analysis, however, allows for the calibration of petrophysical data. The mineral composition, fluid contacts (N/G), permeability, water saturation, and porosity are often revealed via geophysical log data. Just how much filth. Well-logging systems primarily use resistivity, neutron, gamma ray, acoustic density, and image logs as their log measurements. To identify response indications, several measures are employed. New and improved measuring tools are being developed in tandem with technological progress. Remember that well -logging systems cannot directly evaluate critical reservoir features when trying to figure out uncertainty. Data processing, data interpretation, and calibration procedures are necessary to determine the parameters. Because of this, it is easy to execute the same analysis on all wells and there is less room for error due to collection interferences such as borehole effects, tool interference, resolution variances, depth changes, and so on. The petrophysical data generated by these processes is imprecise and difficult to interpret, according to Moore et al. (2011). Since the parameters will vary around the reservoir, the data collected from various locations will also vary. When applied to the entire reservoir, the

April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /https://doi.org/10.5281/zenodo.15127824 ISSN 2488-8648

measurements can identify variations within individual wells, but they may miss larger variations in the monitored properties. This is because the data obtained from the logs only pertain to a limited portion of the reservoir. The net-to-gross ratio of reservoirs is greatly affected by the geological components and layers of clay or shaley that are found there. Therefore, it is crucial to identify these layers. There is sometimes a great deal of ambiguity about this feature when the field is first developing (Ma 2011). One way to determine the thickness and permeability of a reservoir is to conduct a well test. The amount of the reservoir might be significantly affected by a well test in comparison to other well data. Where you are in the pond determines which of the several subterranean features you will encounter. Data dissimilarities for a specific region or facies might be illustrated using histograms. This is because lithologies and facies can be revealed through petrophysical records and reservoir core samples, which can reveal parameter changes. This is the result of excessive usage of histograms. Since the reservoir undergoes natural changes, the histograms reveal how specific attributes evolve with time. It appears that the process is unlikely. However, to determine the correct probability distribution of the parameters at a given location, it is necessary to employ various data measurements together with varied interpretations and knowledge while conducting repeated measurements and charting changes. To make an accurate distribution of chances, this is crucial. Consider how nebulous the idea of scaling up the parameters is. This is because the patterns in the water may not be adequately shown by all wells.

Combining Reservoir Parameters and Probability Distributions

Probabilistic approaches are useful for determining the degree of uncertainty, according to Ma (2011), and there will always be hazy descriptions of reservoirs in the future. In the next section, we shall go into this topic more. When the exact form of an event is unclear, a probability distribution can shed light on the process by which various outcomes are determined. Informing people about the event is another objective. The degree of uncertainty in the expected amount can be demonstrated using probability distributions. The most probable or prevalent outcomes have a higher probability density than the others. It is the probability distribution for the parameter's uncertainty that determines the shape of the probability distributions for the parameter and its functions. Optimal random sampling will decide the forms. Present it as a probability distribution and adjust the parameters as needed for the given data. If further details regarding the reservoir's characteristics are incorporated into the uncertainty assessment, the range of potential outcomes will decrease. The probability distribution will be switched beforer posterior. A function representing pore volume or any other uncertain parameter will have a probability distribution whose precise shape is determined by the functional connection of the relevant uncertainties. The combined distribution of the unknown parameters tends to resemble the normal distribution. According to Bratvold and Begg (2010), the resulting curve is also log-normal when the unknown values are compounded.

According to McVay and Dossary (2014), the concept of the initial probability distribution is investigated. To discover, for the sake of illustration, the genuine probability distribution that results from applying an infinite number of resources to the existing data. The "true" probability distribution could vary from one individual or business to another depending on the specifics of the situation. Risk, according to Bratvold and Begg, is individual and stems from disparities in knowledge, perspective, and evaluation. This topic has been covered extensively by writers. Therefore, even though the original records were generated under identical circumstances, it's conceivable that various companies may have received different amounts of compensation. The accurate measurement of all "true" distributions is anticipated. For the various assessment scenarios to hold water, the probability of an event occurring must be proportional to its frequency. If the other probabilities are conditional, then an event with a P50 chance should occur 50% of the time, as stated by McVay and Dossary (2014). Knowing the potential outcomes of incorrect factor evaluation and improper usage of the probability distribution is quite beneficial. An additional approach is to do a sensitivity analysis to determine whether input variables significantly impact the spread output. Determine the magnitude of the effect that tiny changes in the values of the input factors have on the findings by doing a sensitivity study.

Methodology

The methodology for this project involves data acquisition and loading, stratigraphic framework build-up, structural and stratigraphic modelling, static model, volume computation, structural uncertainty analysis, and effects on volume defined. Below is the workflow summary adopted for this thesis(Figure 3).

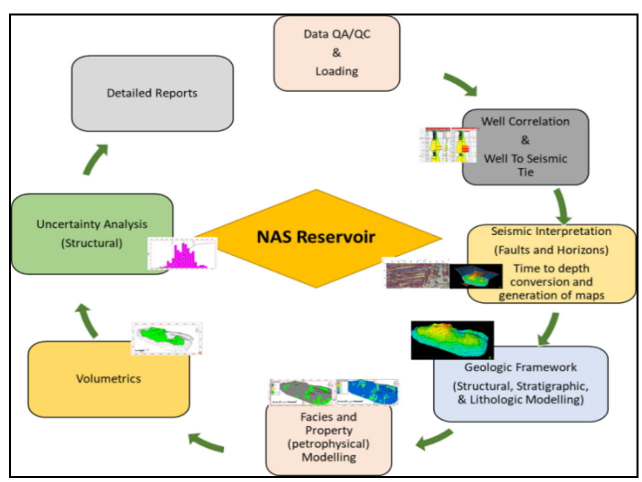


Figure 3:Project workflow

International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /**https://doi.org/ 10.5281/zenodo.15127824** **ISSN 2488-8648**

Result and Discusion

Reservoir well correlation

The well correlation of the field was done along the strike direction because there are only two wells and they lie beside each other along the strike. This resulted in the reservoir tops and bases along correlation paths (Table 1, Figure 1). The average reservoir thickness along the correlation path is from 91ftss (feet sub-sea). The reservoir as seen on the wells is deposited in a transgressive episode of deposition as seen in the fining upwards log signatures of the GR log on both available wells. The implication is that reservoir sand quality deterioratesvertically upwards.

Well to seismic tie

The seismic to well tie shows that a good tie was (correlation coefficient of 89%) at the Nas reservoir of interest (Figure 2). The Nas reservoir corresponds to the peak of the traces for both N-1 and N-2 well to seismic ties. The peaks of the loops were colour- coded red while the troughs blue

Result of the Petrophysical Evaluation

Well,the N-1 top is at 11196ft and the base is at 11286ft while the N-2 top is at 11407ft and the base is at 11500ft. The overall sand thickness for N-1 and N-2 are 90ft and 92tf respectively.Four zones were then interpreted; Heteriolithic zone (1), Sand zone (2), shaly zone (3), and shale zone (4) based on the GR log and interpreted well logs and zonation. Based on critical observation from the well logs, two major reservoir flow unit are that of zone 1 and 2, with zone 2 containingthe cleanest sand while that of zone 1 is heterolithic (i.e intercalation of sand and shale). The petrophysical logs are available for the analysis except for the facies and NTG logs.

The facies log was generated from the GR log using the following If statement-
Facies=If(GR<50,0 ,If(GR>83,2 ,1)……………………….(1)
The NTG was created as a property from the facies. The followingstatement was used-
NTG=If(Facies=2,0,……………………………………..
….(2)
Where 2 refers to facies shale, and 0 and 1 refers to sand (coarse sand and heteroliths respectively).

Table 1: The Nas reservoir tops, bases, and thickness

Wells	N-1	N-2
Top(ftss)	11196	11408
Base(ftss)	11286	11500
Thickness(ftss)	90	92

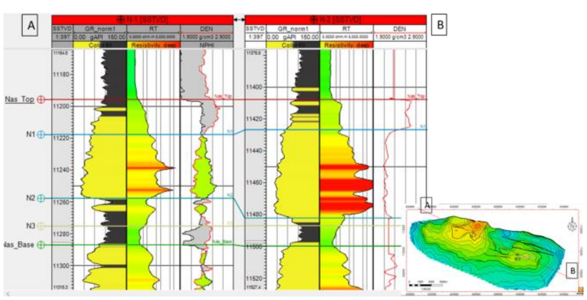
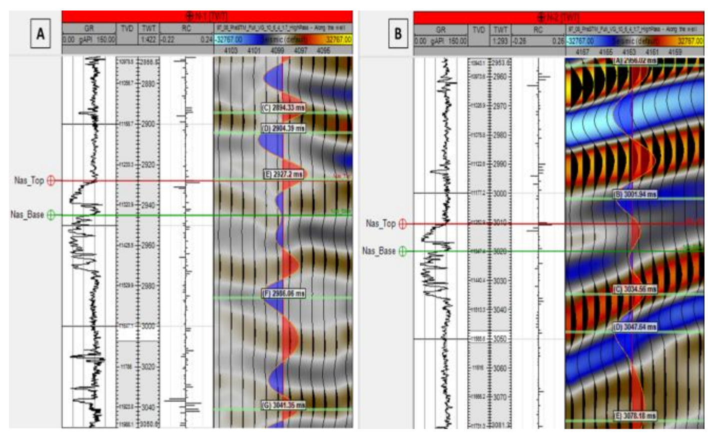


Figure 4: Field wide dip section correlation of the study area showing available wells and correlated reservoirs.



.

Figure 5: Seismic-to-well-tie for wells N-1 and N-2 showing a good tie for the Nass reservoir

Results of Structural Interpretation

Faults and Horizons

A fault network of synthetic and antithetic faults (Figure 3) was interpreted. A total of 12 faults were interpreted along the inline and crossline to the Nass reservoir. Figure 4.4 shows a 3D visualization of interpreted fault sticks. Southern and northern boundary faults were identified. Having tied seismic to well data, Nas reservoirs' time horizon was identified using the synthetic seismic trace and interpreted. The resultant horizon grid is shown in Figure 4.5 for the Nass reservoir top. The Nas reservoir top gridwas interpolated using the Petrel software to create the Nas reservoir time surfaces (Figure6). The Nas reservoir time surface was created with contour intervals of 10ms. The structure is saddled with two crests at the eastern and western flanks of the reservoir of the time structure. The eastern crest occurs at about -2768ms, and thewestern crest at about -2727ms. The reservoir structure is bounded to the north and south by major synthetic and antithetic growth faults respectively. The crest of the Nas structure has low relief with steeper flanks (Figure 6). Crestal faulting is intense with the minor and major intra-reservoir faults creating a fault pattern which trends generally along the structural strike. Flank faulting occurs at a lower frequency than the crest. The interpreted resultant fault sticks were turned into fault polygons for fault modelling.

International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /https://doi.org/10.5281/zenodo.15127824 ISSN 2488-8648

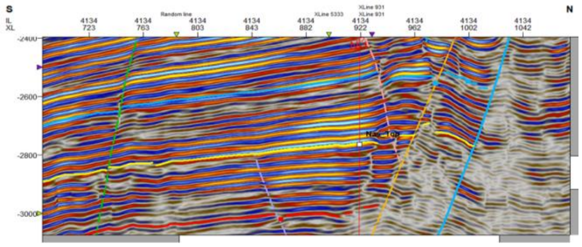


Figure 6: Inline 4134 showing some of the interpreted faults in the field

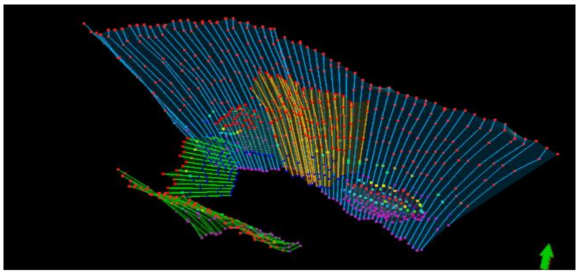


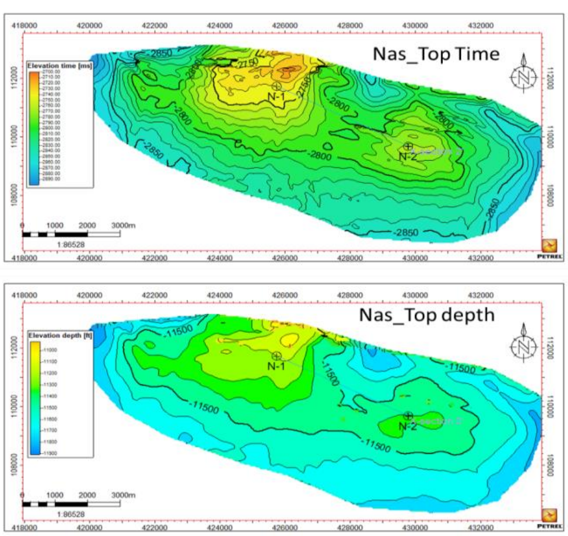
Figure 7: Interpreted faults for the Nas reservoir

Time to Depth Conversion

The fault polygons and reservoir time surfaces were depth-converted using the velocity model. Table 2 shows the residuals after the depth conversion before the flex of the reservoir top. The residuals are 37 ft and 26ft for wells N-1 and N-2 respectively. The average of these residuals is 31.5ft and the standard deviation from this residual is 7.78. The robustness of the velocity model used was further verified by comparing the time and depth surfaces created. This comparison (Figure 7) shows that there is

Table 2: Depth Conversion of N-1 and N-2 with their Average residual and standard deviation.

Wells	Residuals
N1	37
N2	26
Average	31.5
SD	7.78



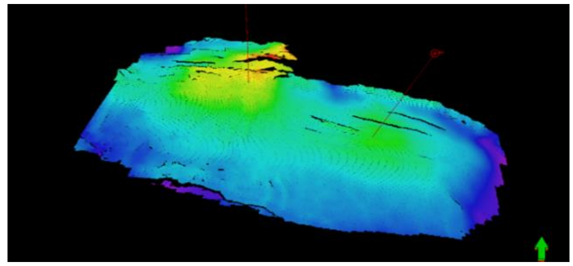


Figure 8: Nas Top reservoir grid

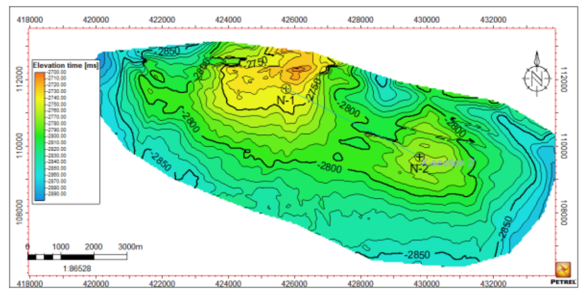


Figure 9: Nas Top time surface

no significant structural difference between the time and depth structural tops. This shows that the process of depth conversions and tying the converted depth surface to well markers did not significantly change the overall structure, and thus there is a high degree of confidence in the velocity model used. The hydrocarbon distribution map is shown in Figure 4.9. Hydrocarbon accumulation is preserved by faults and structural dip closures (Figure 9).

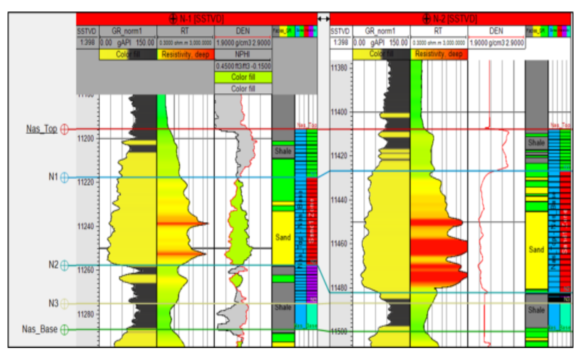


Figure 10: A well section through the Nas reservoir showing interpreted zones

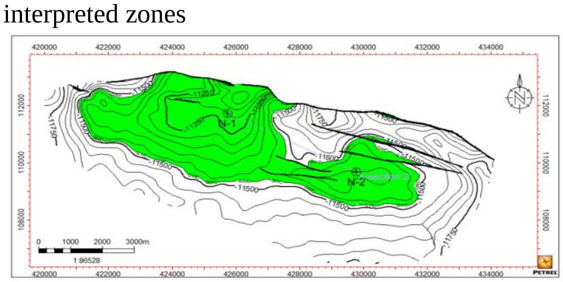


Figure 11: The hydrocarbon distribution map of the Nas reservoir showing the HC exten

International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /https://doi.org/10.5281/zenodo.15127824 ISSN 2488-8648

Figure 12: A comparison between the time and depth structure maps showing negligible structural differences between the two maps

Petrophysical Analysis Results

The interpreted well tops and zonations from petrophysical analysis are shown in Figure 10. Also shown are the facies logs as derived. The petrophysical logs available were quality-checked and made ready for use in petrophysical modelling.

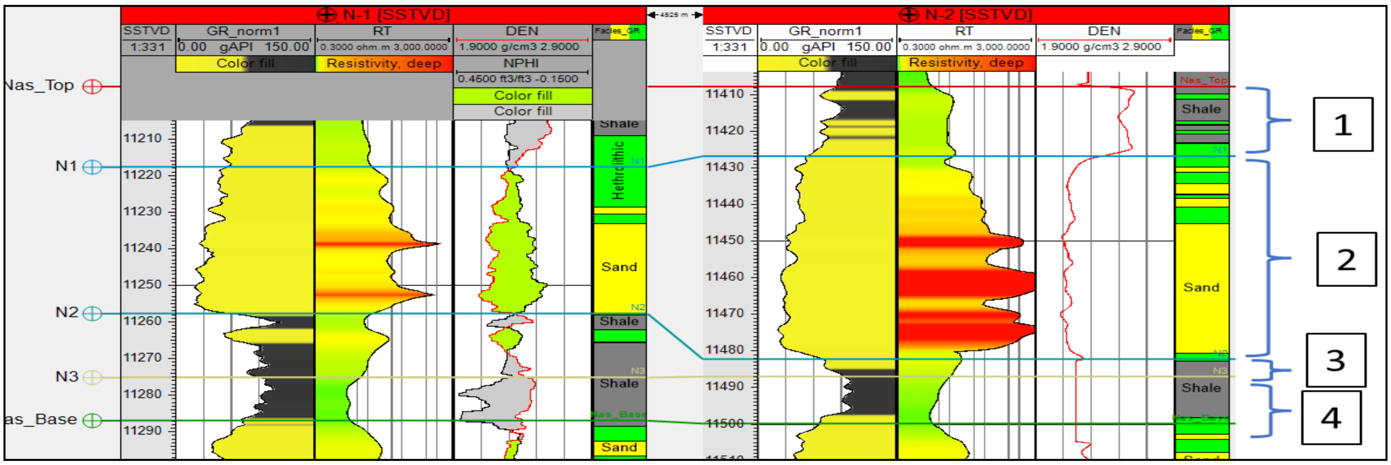


Figure 13: Nas reservoir correlations showing tops, zonation, and the interpreted facies log

Structural Modelling Results

The result of the structural modelling is the reservoir structural top. This is the basic geometrical structure that makes up the external boundaries of the reservoir. Figure 11 shows the modelled fault planes and their relationships with one another in the fault structural model. The modelled reservoir top and base clearly show a low relief top with dipping flanks. Contour terminations at the east westregion indicates a saddle like structure dividing the gas accumulations into two major accumulations (Figure 12).

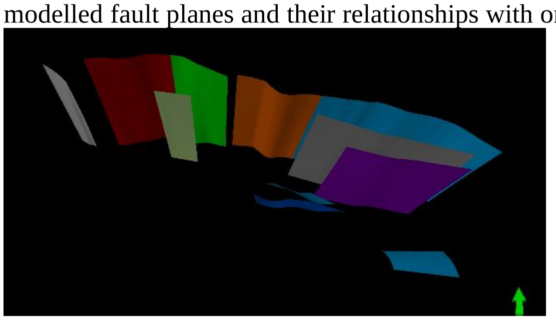


Figure 14 : Nas reservoir fault framework model showing 3D fault relationships

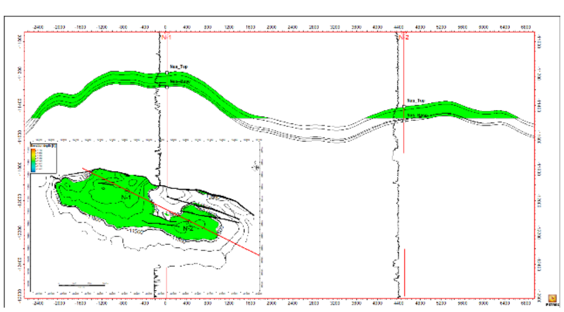


Figure15: Nas reservoir structural framework model showing the reservoir structure and hydrocarbon contacts in map and cross-section

Result of Facies Modelling

Sequential indicator simulation is used in propagating the reservoir facies. The variogram used was obtained from data analysis and modelled facies trend in the general north-south direction. For wells N-1 and N-2, from bottom to the top, four different zones were modelled as follows from the bottom; shale zone (4) comprised completely of shale, a shaly zone (3) with a high proportion of shale followed by sand zone (2) with very clean sand and characterised by sharp base and fining upward sequence based on GR log motif. Then the last zone (1) at the topmost section of the reservoir comprises mostly heteroliths. Well N-2 has less shale at the base in comparison to N-1 (Figure 13).

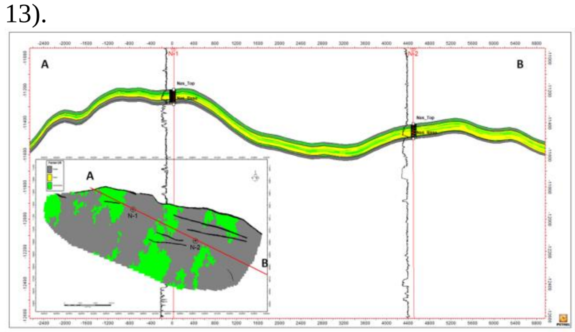


Figure 16: Facies model and cross section of the Nas reservoir

Result of Property Modelling

Net to Gross (NTG)

The net pay is one of the most important parameters in the reservoir characteristics because the penetrated geologic section defines a high grade of hydrocarbon saturation and the best reservoir quality to obtain producing intervals in the reservoir. Net pay demonstrates facilities reservoir simulation since non-

International Journal of Basic Science and Technology
April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /**https://doi.org/10.5281/zenodo.15127824** **ISSN 2488-8648**

reservoir rocks are excluded. NTG was reconstructed based employment of facies (Figure 14). Equation (2) as described in the chapter above was used in generating NTG model.

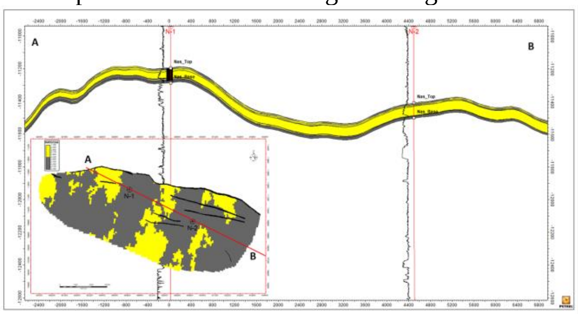


Figure17: NTG model and cross-section of the Nas reservoir

Porosity
Porosity was modelled using variograms from data analysis to determine vertical and horizontal ranges. Upscaled porosity log was propagated stochastically across the Nas reservoir using sequential Gaussian simulation algorithms, the porosity was also populated by each lithofacies type. The distribution of porosity in zone 2 show best quality facies than that of other zones. A summary of the porosity distribution is shown in Table 3.

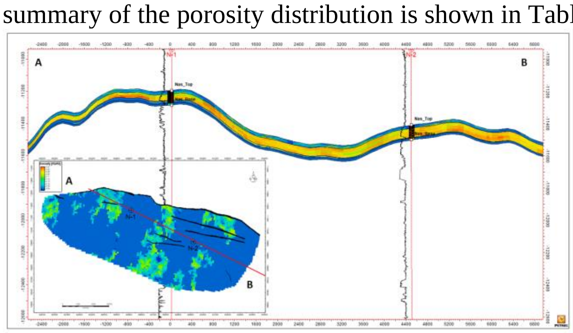


Figure19: Porosity model and cross-section of the Nas reservoir

Water Saturation
Results of water saturation distribution for the two wells N-1 and N-2 are shown in Figure 4.16. well N-1 have high water saturation while well N-2 have low water saturation.

Structural Uncertainty Analysis
Figures 4.18 show the results of the structural analysis. The figure shows the base structure in red, and some of the different structural possibilities from the uncertainty run (in black) using the standard deviation from the time-to- depth conversion (Table 2). The distribution histograms for the uncertainty runs show the approximate low, mid, and high values for GIIP, which in turn affects the HC volume. The actual effect on HC volume is shown

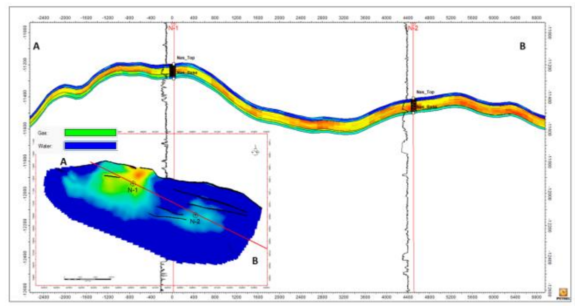


Figure18: Sw model and cross-section of the Nas reservoir

Table 3: Zonation and layer divisions of the facies and Petrophysical values of the Nas reservoir model

Zone Names	Zone Divisions (Layers)	Porosity Range	
1	1	0.04-0.16	0.54-1.00
2	30	0.18-0.28	0.0048-0.62
3	1	0.05-0.24	0.20-0.95
4	20	0.04-0.0.06	0.43-1.00

Estimation of in-place hydrocarbons
The reservoir structure is saddled with two highs confined in the form of four-way closures. Gas-water contact was used to estimate the bulk volume. Gas initially in place (GIIP) was calculated using NTG, Porosity, and Sw models. The calculated GIIP is 67Bscf.

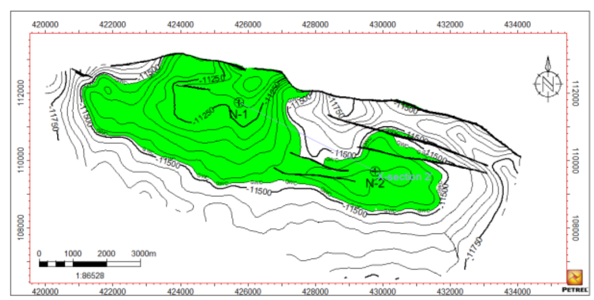


Figure 20: Gas distribution map of the NAS reservoir

in histograms in Figure 19. From the histogram, uncertainty volume distributions show the low, mid and high GIIP as 67 Bscf, 63Bscf, and 58Bscf respectively. While the GRV based on structural uncertainty are high volume: 367,000 acres.ft, Base volume: 349,000 acre.ft, and low volume:329,000acreft (Figure 20). The mid case volume represents a 6% increase from the low while the high case represents a 5% increase from the mid.

April, Volume 11, Number 1, Pages 24 - 37 http://www.ijbst.fuotuoke.edu.ng /https://doi.org/10.5281/zenodo.15127824 ISSN 2488-8648

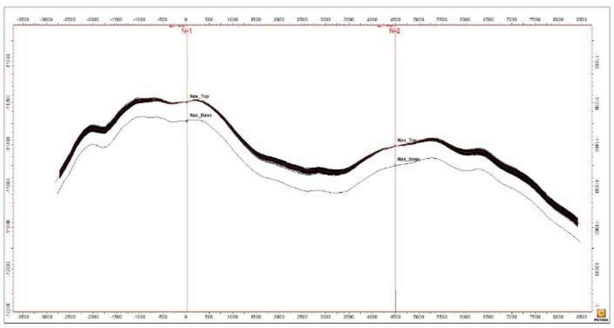


Figure 21: Structural realizations for NAS reservoir top

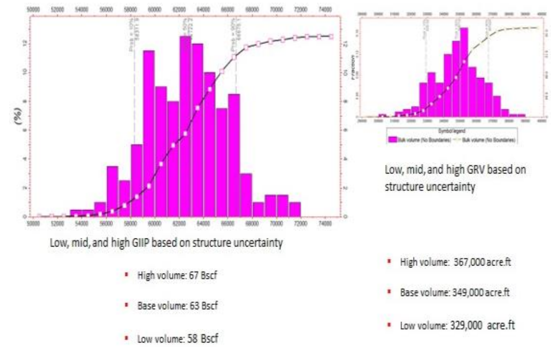


Figure 22: Low, mid, and high GIIP AND GRV based on structure uncertainty

Conclusion

In conclusion, this project has confirmed that even with very limited data, a concise and reliable field development can be undertaken and the results used for informed decision-making if the uncertainties can be defined and quantified. A static model was built for the NAS reservoir which highlights the reservoir properties and variations. The uncertainty in volume in place as a result of the structure shows a 6% increase from the low case volume, and the high case represents a 5% increase from the mid-case volume.

References

Aanuoluwa, A.A., Sunmonu, L.A., Olusola, K., and Ojoawo, I. A. (2017). Trap analysis of "Covenant" field in Niger Delta, Nigeria.

Ajisafe, Y.C., and Ako, B.D. (2013). 3D seismic attributes for reservoir characterization of 'Y' Field Niger Delta, Nigeria. *IOSR Journal of Applied Geology and Geophysics, 1*, 23–31.

Armitage, D.A. (2012). Postavulsion channel evolution: Niger Delta continental slope. *American Association of Petroleum Geologists Bulletin, 96*(5), 823–843. https://doi.org/10.1306/10171111081

Bickel, J.E., and Bratvold, R.B. (2007). *Decision making in the oil and gas industry: From blissful ignorance to uncertainty-induced confusion* [Paper presentation]. SPE Annual Technical Conference and Exhibition, Anaheim, California, United States. https://doi.org/10.2118/109610-MS

Bond, C.E. (2015). Structural model creation: The impact of data type and creative space on geological reasoning and interpretation. *Geological Society, London, Special Publications, 421*, 83–97. https://doi.org/10.1144/SP421.4

Bustin, R.M. (1988). Sedimentary and characteristics of disperse organic matter in Tertiary Niger Delta: Origin of source rocks in a deltaic environment. *American Association of Petroleum Geologists Bulletin, 72*(3), 277–298.

Corre, B.T. (2000). *Integrated uncertainty assessment for project evaluation and risk analysis* [Paper presentation]. SPE European Petroleum Conference, Paris, France. SPE-65205.

Culshaw, M.G. (2005). From concept towards reality: Developing the attributed 3D geological model of the shallow subsurface. *Quarterly Journal of Engineering Geology and Hydrogeology, 38*(3), 231–284. https://doi.org/10.1144/1470-9236/04-072

Demirmen, F. (2001). *Subsurface appraisal: The road from reservoir uncertainty to better economics* [Paper presentation]. SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, Texas. SPE-68603.

Doust, H., and Omatsola, E. (1990). Niger Delta. In J.D. Edwards & P.A. Santogrossi (Eds.), *Divergent/passive margin basins* (AAPG Memoir 48, pp. 239–248). American Association of Petroleum Geologists.

Edwards, M.B. (2000). Origin and significance of retrograde failed shelf margin; Tertiary northern Gulf Coast basin. *Transactions of the Gulf Coast Association of Geological Societies, 50*, 239–248.

Ekwere, P. (2010). *Advanced petrophysics*. African University of Science and Technology.

Fazli Khani, H., and Back, S. (2012). Temporal and lateral variation in the development of growth faults and growth strata in the western Niger Delta, Nigeria. *American Association of Petroleum Geologists Bulletin, 96*(4), 595 – 614. https://doi.org/10.1306/08101110134

Jessell, M.W., Pakyuz-Charrier, E. and Lindsay, M. (2018). Assessing and mitigating uncertainty in three-dimensional geologic models in contrasting geologic scenarios. In *Metals, minerals, and society* (pp. 1–20). Society of Economic Geologists. https://doi.org/10.5382/SP.21.04

Kelkar, M., and Perez, G. (2002). *Applied geostatistics for reservoir characterization*. Society of Petroleum Engineers.

Ma, Y.Z. (2011). *Uncertainty analysis in reservoir characterization and management: How much should we know about what we don't know?* Society of Petroleum Engineers.

McVay, D.A., and Dossary, M. (2014). The value of assessing uncertainty. *SPE Economics & Management, 6*(2), 100–110. https://doi.org/10.2118/160189-PA

Meisingset, K.K. (1999). Uncertainties in reservoir fluid description for reservoir modeling. *SPE Reservoir Evaluation & Engineering, 2*(5), 428–434.

Moore, W.R., Ma, Y.Z., Urdea, J., & Bratton, T. (2011). Uncertainty analysis in well-log and petrophysical interpretations. *SPE Reservoir Evaluation & Engineering, 14*(3), 330–338.

Pakyuz-Charrier, E., Giraud, J., Lindsay, M., & Jessell, M. (2018a). Drillhole uncertainty propagation for three-dimensional geological modeling using Monte Carlo. *Tectonophysics, 747–748*, 16–39. https://doi.org/10.1016/j.tecto.2018.09.005

Pakyuz-Charrier, E., Jessell, M., and Lindsay, M. (2019). Topological analysis in Monte Carlo simulation for uncertainty estimation. *Solid Earth Discussions*. https://doi.org/10.5194/se-2019-78

Pakyuz-Charrier, E., Lindsay, M., and Jessell, M. (2018b). Monte Carlo simulation for uncertainty estimation on structural data in implicit 3-D geological modeling, a guide for disturbance distribution selection and parameterization. *Solid Earth, 9*, 385–402. https://doi.org/10.5194/se-9-385-2018

Rensbergen, P.V., and Morley, C.K. (2000). Three-dimensional study of a shale expulsion syncline at the base of the Champion delta, offshore Brunei and its implication for the early structural evolution of large

Turner, A.K., and Gable, C.W. (2007). A review of geological modeling. *GSA Reviews in Engineering Geology, 18*, 11–26.

Walstrom, J.E. (1967). Evaluating uncertainty in engineering calculations. *Journal of Petroleum Technology, 19*(12), 1595–1603.

delta systems. *Marine and Petroleum Geology, 17*(7), 861–872. https://doi.org/10.1016/S0264-8172(00)00031-8

Reijers, T.J.A., Petters, S. W., and Nwajide, C. S. (1997). The Niger Delta Basin. In *Sedimentary basins of the world* (Vol. 3, pp. 151–172). Elsevier. https://doi.org/10.1016/S1874-5997(97)80010-X

Ringrose, P., and Bentley, M. (2015). *Reservoir model design: A practitioner's guide*. Springer.

Sandsdalen, C., Barbieri, M., Tyler, K., & Aasen, J. O. (1996). *Applied uncertainty analysis using stochastic modelling* [Paper presentation]. SPE European 3D Reservoir Modelling Conference, Stavanger, Norway. SPE-35533.

Schneeberger, R., de La Varga, M., Egli, D., & Berger, A. (2017). Methods and uncertainty estimations of 3D structural modelling in crystalline rocks: A case study. *Solid Earth, 8*, 987– 1002 https://doi.org/10.5194/se-8-987-2017

Simpson, G.S., Lamb, F.E., Finch, J.H., & Dinnie, N.C. (2000). *The application of probabilistic and qualitative methods to asset management* [Paper presentation]. SPE Asia Pacific Conference on Integrated Modelling for Asset Management, Yokohama, Japan. SPE-59455. https://doi.org/10.2118/59455-MS

Stamm, F.A., Wellmann, J.F., and Caers, J. (2019). Actors, actions and uncertainties: Optimizing decision making based on 3-D structural geological models. *Solid Earth, 10*, 2015–2043. https://doi.org/10.5194/se-10-2015-2019

Wellmann, F., and Caumon, G. (2018). 3-D structural geological models: Concepts, methods, and uncertainties. *Advances in Geophysics, 59*, 1–121. https://doi.org/10.1016/bs.agph.2018.09.001

Whitson, C.H., and Brule, M.R. (2000). *Phase behavior* (Monograph Series, Vol. 20). Society of Petroleum Engineers.