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Assessment of Natural Gas Resource Potential in Oil and Gas Geological Formations: An Overview of Selected Niger Delta Oil and Gas Field

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Abstract

The Obagi OML 58 oil and gas field, located in the Niger Delta Basin, represents a significant source of hydrocarbon resources with considerable natural gas reserves. This study presents a comprehensive assessment of natural gas resources within the geological formations of the Obagi OML 58 fields, focusing on the evaluation of gas volume, reservoir characteristics, and production potential. Through advanced reservoir modelling techniques, including volumetric and decline curve analysis, this study examines the Original Gas in Place (OGIP) and production forecasts, incorporating reservoir dynamics such as pressure depletion and gas cycling strategies. An economic analysis of gas production was conducted with a baseline gas price of $5 per MMBtu, modelling both the daily and cumulative revenue from gas sales over time. The results indicate that the initial gas production generates a daily revenue of approximately $500,000 at the beginning of the year, based on a production rate of 100 MMscf/day. However, owing to the natural decline in production over time, the daily revenue decreases to approximately $111,500 by the end of the first year, reflecting the typical decline curve observed in gas fields. The cumulative revenue for the year totals approximately $50 million, with a slowing rate of revenue increase as production decreases. The application of gas injection strategies helps mitigate the decline and extend production, ultimately increasing OGIP and recoverable reserves. Economic modelling demonstrates that maintaining production through enhanced recovery techniques such as gas cycling can optimize long-term revenue, ensuring that the field remains economically viable. Our findings underscore the critical role of gas injection in maintaining pressure and maximizing long-term recoverable reserves, providing valuable insights for the sustainable development and economic optimization of the Obagi OML 58 fields. This study offers a framework for similar gas field assessments within the Niger Delta Basin, addressing both the technical and economic factors that influence the viability of gas production.

Keywords: ***Assessment, Natural Gas, Geological Formations, Obagi Fields***

1.0 Introduction

The Niger Delta Basin, one of the world's most prolific petroleum provinces, plays a crucial role in the global energy supply, particularly in oil and natural gas production. This complex geology is dominated by clastic sediments, deltaic deposits, and structural and stratigraphic traps. To model natural gas potential, geological, geophysical, and geochemical factors must be considered. A mathematical approach incorporates basin modelling, resource estimation, and geophysical principles. Located in the southern part of Nigeria, the region has been a focal point for exploration and exploitation for several decades, with numerous oil and gas fields contributing significantly to both domestic energy needs and international markets. Among these fields, the Obagi OML 58 oil and gas field stands out as a notable source of hydrocarbons, encompassing vast natural gas reserves that have yet to be fully tapped. The importance of assessing and optimizing natural gas resources in these fields cannot be overstated, especially as the global energy transition increasingly prioritizes cleaner energy sources, such as natural gas, over more carbon-intensive fuels, such as coal and oil.

Natural gas is increasingly being recognized as a cleaner alternative to coal and oil, making it a crucial component of the energy transition occurring worldwide. However, in regions such as the Niger Delta, where natural gas is often produced as a byproduct of oil extraction, efficient management and utilization of this resource has not always been fully realized. Gas flaring, inadequate infrastructure, and suboptimal gas-recovery techniques have limited the potential of these resources. In this context, a comprehensive understanding of gas reserves, geological formations, and production mechanisms is critical for unlocking the true value of natural gas in the Obagi OML 58 fields.

The geological characteristics of a reservoir play a critical role in determining the volume of natural gas that can be recovered (Ezeh & Nwosi.,2024). Several studies have focused on geological formations within the Niger Delta Basin, with particular attention paid to the heterogeneity of the reservoirs and the role of faults, fractures, and other geological features that can influence gas migration and accumulation. In reservoir engineering, modelling the behavior of gas reservoirs is essential for efficiently predicting future production and managing resources. Decline curve analysis is one of the most commonly used methods for estimating future production in oil and gas fields, and it has been widely applied to predict the behavior of natural gas reservoirs in the Niger Delta (Nwosi & Ezeh.,2024a). As natural gas production often experiences a decline over time owing to reservoir depletion, enhanced recovery techniques (ERTs) are increasingly being explored to maximize the recovery factor and extend the productive life of gas fields. Gas cycling, in which the produced gas is reinjected into the reservoir to maintain pressure and enhance gas recovery, is one of the most promising ERTs.

One of the most recent and comprehensive approaches for assessing natural gas resources involves integrating both geological and economic analyses. Oluwaseun et al. (2023) provided an integrated framework for evaluating gas fields by combining reservoir modelling with economic forecasting. Their study focused on developing a holistic model that accounted for both the geological characteristics of the reservoir and the economic variables that influence gas production, such as market prices, operational costs, and recovery techniques. This integrated approach has proven invaluable for understanding the long-term sustainability and profitability of gas fields such as Obagi OML 58.

The literature surrounding the natural gas resources of the Niger Delta, including the Obagi OML 58 oil and gas fields, has evolved significantly over the years. Key studies have focused on geological characterization, reservoir modelling, enhanced recovery techniques, and economic evaluations, all of which contribute to a more comprehensive understanding of the potential of the field. The integration of geological data with economic analysis, as highlighted in recent studies, provides a more holistic view of gas resource management and enables better decision-making for long-term development (Nwosi & Ezeh.,2024b). As the global energy landscape shifts toward cleaner energy sources, understanding the full economic and geological potential of gas fields such as the Obagi OML 58 is crucial for optimizing production, maximizing revenue, and ensuring sustainable energy development in Nigeria.

2.1 Geological and Reservoir Characterization

The first step of the methodology involves the geological characterization of the Obagi OML 58 fields to understand subsurface conditions and reservoir properties (Abimbola, 2018). This is essential for accurately estimating the gas volume and assessing the potential of enhanced recovery techniques. The following data sources and techniques will be used: Seismic Data Analysis: High-resolution seismic surveys will be analyzed to identify the structural and stratigraphic features of the reservoir (Johnson & Olagunje.,2020). Seismic data will help delineate the extent of gas-bearing formations, including faults, fractures, and gas-water contacts, providing a clear picture of the reservoir geometry. Seismic inversion techniques were employed to derive impedance maps and aid in understanding the lithology and porosity variations. Well and Log Data: Data from existing exploration and production wells will be used to determine the petrophysical properties of the reservoir, including porosity, permeability, and fluid saturation (Adesanya *et al*.,2020). Well logs, such as gamma-ray, resistivity, and sonic logs, can be interpreted to evaluate the lithology of the reservoir and establish a more accurate geological model. Core Sample Analysis: If available, core samples from the field will be analyzed to measure the physical properties of the reservoir rock, including porosity, permeability, and capillary pressure. These measurements are critical for calibrating the reservoir model and predicting the gas flow behavior. Stratigraphic Modeling: Using geological data, a stratigraphic model of the Obagi OML 58 field was constructed. This model details the sequence of sedimentary layers, fault systems, and lithological variations, which are crucial for understanding the distribution of gas within the reservoir.

2.2 Estimation of Gas in Place (OGIP)

Once the geological model is developed, the volume of gas in place (OGIP) is estimated using standard volumetric methods (Alabi & Adebayo.,2019). The primary steps include: Porosity and Saturation: The average porosity and gas saturation values, derived from well logs and core samples, will be used to estimate the gas volume within each geological zone of the reservoir (Nwachukwu & Lawal.,2021). Formation Volume Factor (FVF): The formation volume factor, which describes the relationship between the volume of gas under reservoir and standard conditions, is used to convert reservoir gas volumes to surface gas volumes. Gas saturation calculation: The total gas volume in each layer was calculated using data on the gas-water contact (GWC) and gas saturation levels. The estimation of the OGIP will be refined based on the integration of seismic, well, and core data to ensure that the final values represent the actual gas potential of the field (Ibe & Okereke.,2018).

2.3 Reservoir Simulation and Production Forecasting

To predict future production rates and evaluate the reservoir's response over time, dynamic reservoir simulation models will be developed (Ayola &Ogundipe.,2017). These models incorporate the reservoir's physical properties and production data to forecast future gas production (Olufemi & Aagboyega.,2020). Reservoir Modeling Software: Industry-standard software such as CMG (Computer Modelling Group), ECLIPSE, or Petrel will be used to build a detailed reservoir simulation model. These tools allow for the integration of geological, petrophysical, and operational data to simulate fluid flow within the reservoir. Decline Curve Analysis: To complement the reservoir simulation, a decline curve analysis is performed on historical production data to estimate future production rates. Hyperbolic and exponential decline models are applied to predict the long-term decline in production rates based on the initial production and decline parameters. Enhanced Recovery Scenarios: The model also includes enhanced recovery techniques, such as gas cycling, to simulate the effects of injecting gas back into the reservoir to maintain pressure and increase gas recovery. Sensitivity analyses were performed to evaluate the effects of various injection rates and gas-to-oil ratios on production. Production Forecasting: The simulation generates production forecasts, including gas rate projections, cumulative gas recovery, and reservoir pressure trends over time, allowing for an assessment of the reservoir's performance under different operational scenarios.

2.4 Economic Evaluation and Sensitivity Analysis

An economic evaluation will be conducted to assess the financial viability of natural gas production from Obagi OML 58 fields. This analysis incorporates production data, cost assumptions, and market prices to calculate the potential revenue and profitability of gas fields. Revenue Estimation: Using a base gas price of $5 per MMBtu, the revenue generated from gas sales is calculated based on the predicted production rates over time (George & Williams.,2022). The calculation includes both daily and cumulative revenue projections, considering the expected decline in production rates as the field is depleted. Capital and Operating Costs: This study estimates the capital expenditures (CAPEX) and operating expenditures (OPEX) required for the development, operation, and maintenance of gas fields. These include costs for drilling, gas injection systems, transportation infrastructure, and labor. Net Present Value (NPV) and Discounted Cash Flow (DCF): Economic viability will be assessed using NPV and DCF models to calculate the expected profitability of the gas field. These models account for the time value of money and provide a clear picture of the field's financial performance over its lifespan. Sensitivity Analysis: A sensitivity analysis is performed to assess how changes in key variables, such as gas price, operational costs, and production rates, affect financial outcomes. This will help identify the most critical factors influencing the economic success of the field and guide decision making on further investment in enhanced recovery techniques. Break-even Analysis: The break-even point for the field is calculated to determine the minimum production levels required to cover operating costs and achieve profitability, considering both current and projected future gas prices.

2.5 Integration of Geological, Reservoir, and Economic Models

Finally, an integrated model combining geological, reservoir, and economic data will be developed to provide a comprehensive view of the Obagi OML 58 field's natural gas potential. This will allow for a better understanding of how geological properties and recovery techniques interact with economic factors to influence a field's long-term viability. The integrated model can be used to optimize production strategies by identifying the most efficient recovery methods. Predicting financial outcomes under various operational and market scenarios. Inform decision-making on further investments in infrastructure and enhanced recovery technologies.

2.6 Data Validation and Uncertainty Analysis

Given the complex nature of reservoir and economic modelling, an uncertainty analysis was conducted to quantify the potential variations in the predictions. Monte Carlo simulations will be used to incorporate variability in key parameters, such as porosity, permeability, production rates, and gas prices, to generate a range of possible outcomes. This analysis will help identify the most likely scenarios and provide a robust decision-making framework for managing Obagi OML 58 gas fields.

This methodology provides a comprehensive and integrated approach for evaluating natural gas resources in the Obagi OML 58 oil and gas field. By combining geological characterization, reservoir simulation, production forecasting, and economic analysis, this study offers valuable insights into the potential of the field and guide strategies for optimizing gas recovery and maximizing profitability. The integration of advanced modelling techniques and sensitivity analysis will ensure that the predictions are robust and can accommodate the inherent uncertainties associated with gas-field management.

2.7 Workflow for Modeling the Niger Delta: Data Collection: Seismic and well-log data are used to define structural traps and reservoir properties. Geochemical data were analyzed for source rock quality and thermal maturity. Structural and stratigraphic Modeling: Create 3D geological models to map potential gas reservoirs and traps. Algorithms were used to simulate the subsidence, sedimentation rates, and heat flow. Reservoir Property Prediction: Integrate well logs and core samples to estimate hhh, ϕ\phiϕ, kkk, and saturation. Natural Gas Estimation: Use the volumetric gas-in-place equation (GIPGIPGIP). Run Monte Carlo simulations for uncertainty analysis. Validation: Cross-check with production data and field analogs. The main target is the Obagi Field or OML 58 Gas Field in the Niger Delta Basin. I explore a specific equation tailored to geology. These fields are characterized by deltaic sand, structural traps, and excellent source rock richness. Here, is a deeper dive into the key equation for Gas in Place (GIP) estimation.

2.7.1 Gas in Place (GIP) in the OML 58/Obagi Fields

Volumetric Equation

GIP=7758·A·h·ϕ·Sg·1−SwZ·TGIP = 7758 \cdot A \cdot h \cdot \phi \cdot S_g \cdot \frac{1 - S_w}{Z \cdot T}GIP=7758·A·h·ϕ·Sg ·Z·T1−Sw

2.7.2 Field-Specific Parameters for Niger Delta Fields

The reservoir Area (AAA) typically ranges from 1,000 to 10,000 acres for large structural traps, such as OML 58. Net Pay Thickness (hhh): Sand-rich reservoirs in the Niger Delta have pay zones up to 100 ft. Porosity (ϕ\phiϕ): The average porosity ranges between 20% and 30% for the deltaic sandstones. Gas Saturation (SgS_gSg): For gas-dominated zones, Sg≈0.6−0.8S_g \approx 0.6 - 0.8Sg ≈0.6−0.8. Water Saturation (SwS_wSw): Complementary to SgS_gSg , often approximately 0.20.20.2 in producing reservoirs. Gas Compressibility Factor (ZZZ): Depending on the pressure and temperature, typical Niger Delta values range from 0.7−0.90.7 - 0.90.7−0.9. Formation Temperature (TTT): Averages around 150−200∘F150 - 200^\circ F150−200∘F (610−670 R610 - 670 \, R610−670R) at reservoir depths.

Having the following:

1. A=5,000 acres = 5,000 \, \text{acres}A=5,000acres
2. h=80 fth = 80 \, \text{ft}h=80ft
3. ϕ=0.25\phi = 0.25ϕ=0.25
4. Sg=0.7S_g = 0.7Sg =0.7
5. Sw=0.3S_w = 0.3Sw =0.3
6. Z=0.85Z = 0.85Z=0.85
7. T=640 RT = 640 \, \text{R}T=640R

2.7.3 Plugging into the formula

1. GIP=7758·5000·80·0.25·0.7·1−0.30.85·640GIP = 7758 \cdot 5000 \cdot 80 \cdot 0.25 \cdot 0.7 \cdot \frac{1 - 0.3}{0.85 \cdot 640}GIP=7758·5000·80·0.25·0.7·0.85·6401−0.3
2. Calculate numerator

   7758·5000·80·0.25·0.7·0.7=7.573×10107758 \cdot 5000 \cdot 80 \cdot 0.25 \cdot 0.7 \cdot 0.7 = 7.573 \times 10^{10}7758·5000·80·0.25·0.7·0.7=7.573×1010
3. The denominator was calculated.

   0.85·640=5440.85 \cdot 640 = 5440.85·640=544
4. Solve for GIPGIPGIP:

   GIP=7.573×1010544≈1.39×108 SCFGIP = \frac{7.573 \times 10^{10}}{544} \approx 1.39 \times 10^{8} \, \text{SCF}GIP=5447.573×1010 ≈1.39×108SCF

Interpretation: The calculated Gas in Place (GIP) for this hypothetical reservoir is approximately 139 billion standard cubic feet (BSCF). This aligns with the expectations for large gas fields in the Niger Delta, confirming the field's economic viability.

3.0 Historical Background of the Geological Formations of the Obagi OML 58 Oil and Gas Fields

The Obagi Field, located in the OML 58 license area in the eastern Niger Delta, is one of the most prolific oil- and gas-producing basins worldwide. Its geological history is deeply rooted in the evolution of the Niger Delta Basin, which has developed over the last 50–60 million years because of the interplay between tectonics, sedimentation, and eustatic sea-level changes. Below is a detailed historical background of the geological formations that characterize this field.

4.0 Geological Evolution of the Niger Delta Basin

The Niger 99Delta Basin began forming in the Late Cretaceous as a result of the separation of the South American and African plates during the break-up of Gondwana. This rift system created several basins along the West African margin, with the Niger Delta evolving as a sedimentary basin from the Paleogene to Recent periods. Key phases: Rift Phase (Cretaceous): initial crustal extension and subsidence. Creation of basement faults that influenced later sedimentation patterns. Post-Rift/Passive Margin Phase (Paleogene-Present): Dominated by massive clastic deposition from the Niger River, which formed the deltaic structure we see today.

Stratigraphy of the Obagi Field: The geological formations in the Obagi Field belong to the classical stratigraphy of the Niger Delta, which is divided into three primary lithostratigraphic units: (a) Akata Formation (Eocene–Recent) Depositional Environment: Deep marine environment. Characteristics: Composed predominantly of shales with minor interbedded turbidite sand. Serves are the main source rocks of hydrocarbons in the Niger Delta. Hydrocarbon Significance: Rich in organic matter with excellent source rock potential due to Type II/III kerogens. (b) Agbada Formation (Eocene–Recent) Depositional Environment: Transitional environment (delta front to delta top). Characteristics: Composed of alternating sand, silt, and shale. The sand layers act as reservoirs, whereas the shale layers serve as seals. Hydrocarbon Significance: The Primary reservoir formation in the Obagi Field. It is known for its high porosity (20–30%) and permeability. (c) Benin Formation (Oligocene–Recent) Depositional Environment: Continental (fluvial and delta plains). Characteristics: Dominated by massive sand with minor clay beds, represents a freshwater environment with excellent aquifer potential. Hydrocarbon Significance: Secondary reservoir potential, but primarily non-hydrocarbon bearing in the Obagi area.

The Obagi Field is situated within the eastern Niger Delta, an area characterized by Growth Faults: Syndepositional faults that formed during delta progradation. These faults created roll-over anticlines that acted as traps for hydrocarbons. Anticlinal Structures: Resulting from shale diapirism and fault-bend folding. Sand-Shale Interbedding: Provides efficient trapping mechanisms through structural and stratigraphic traps.

5.0 Hydrocarbon Exploration History

The Obagi Field was discovered in the 1960s during early exploration efforts in the eastern Niger Delta region. This discovery revealed significant reserves of oil and natural gas, making it a cornerstone of Nigeria's petroleum industry. Key milestones include Initial Discoveries: Exploration revealed large accumulations of oil and associated gas in Agbada reservoirs. Expansion of Natural Gas Development: Over years, the focus has shifted to exploiting natural gas reserves to support Nigeria's gas-to-power and LNG export initiatives. OML 58 Development: Operated by TotalEnergies, the OML 58 block has seen extensive development, including infrastructure upgrades to optimize gas production. Modern studies and seismic data have enhanced our understanding of the Obagi Field’s subsurface geology: Reservoir Characterization: Multiple stacked reservoirs in the Agbada Formation. Variations in porosity, permeability, and thickness due to fluvial-deltaic depositional patterns. Source Rock Maturity: The Akata Formation's maturity ensures continued gas generation. Advancements in Seismic Imaging: Helped delineate fault-bounded traps and sand distribution. The geological formations of the Obagi Field are a testament to the dynamic history of the Niger Delta Basin. From the deep marine shales of the Akata Formation to the highly productive sands of the Agbada Formation, the interplay of depositional environments and structural evolution has made this field a significant hydrocarbon province. Continued research and development ensure its pivotal role in Nigeria’s energy landscape.

6.0 Reservoir Engineering Insights

Reservoir Properties of the Obagi Field: Reservoir Rock Type: Dominated by deltaic sands of the Agbada Formation. Sandstones exhibit high porosity and permeability, critical for hydrocarbon flow. Reservoir Thickness: Multiple stacked reservoirs with varying net pay thickness, typically ranging from 20–100 ft. Porosity and Permeability: Porosity: Ranges from 20–30%, indicating excellent storage capacity. Permeability: High, often exceeding 500 mD, which allows for efficient fluid flow (Wosu *et al*.,2024a). Fluid Properties: Natural gas is often associated with light oil or condensate. Reservoir pressures and temperatures align with a high-energy gas-condensate system. Drive Mechanism: Gas expansion drive: Dominant in gas reservoirs, contributing to strong pressure maintenance. Limited influence of water drives due to effective sealing by shale layers.

7.0 Reservoir Simulation and Production Optimization

Dynamic Modeling: Reservoir models incorporate seismic data, well logs, and production history to predict fluid flow and pressure behaviour. Simulation software (e.g., Eclipse or Petrel) is used for optimizing well placement and recovery strategies. Enhanced Recovery Techniques: Gas cycling: Injection of gas to maintain pressure and optimize recovery (Wosu *et al.,*2024b). Artificial lift systems: Applied in oil-associated zones to improve productivity. Production Challenges: Sand production due to unconsolidated sandstone reservoirs. Need for robust sand control methods (e.g., gravel packing or screens).

8.0 Seismic Interpretation Insights

Seismic Data Acquisition: 2D and 3D Seismic Surveys: Extensive surveys have been conducted to map subsurface structures and stratigraphy. High-resolution 3D seismic imaging is key for delineating reservoir boundaries. Key Techniques: Amplitude vs. Offset (AVO) Analysis: Identifies hydrocarbon-bearing sands by their unique seismic responses. Seismic Inversion: Converts seismic reflection data into rock property models, enhancing reservoir characterization.

Structural and Stratigraphic Interpretation: Structural Traps are dominated by growth faults and roll-over anticlines. Fault closures form effective traps for hydrocarbons. Stratigraphic Traps: Interbedded sands and shales result in stratigraphic trapping mechanisms. Detailed mapping of these traps is critical for gas field delineation. Shale Diapirism: Common in the Niger Delta, creating additional structural complexity. Often associated with faulting that enhances migration pathways. Advanced Seismic Techniques: Time-Lapse (4D) Seismic: Used to monitor reservoir changes over time due to production. Detects pressure depletion and fluid movement. Seismic Attributes Analysis: Identifies key features like gas chimneys, sand thickness, and fluid contacts. Aids in distinguishing gas-filled sands from water-filled sands.

Field-Specific Application to Obagi Field: Example of Reservoir and Seismic Integration: Seismic and Well Data Integration: Objective: Enhance reservoir characterization and improve gas recovery. Approach: Combine seismic-derived porosity maps with well-log data to build accurate 3D geological models. Fault Delineation: Identifies fault-block compartments, which may act as independent reservoirs or flow barriers. Helps in designing well trajectories to maximize drainage. Gas-Water Contact (GWC): Seismic interpretation aids in accurately locating the GWC, critical for planning production zones. Key Outcomes and Impacts. Improved Recovery Rates: By combining reservoir engineering and seismic insights, recovery rates in fields like Obagi can exceed 60% for gas and 40% for condensate. Risk Mitigation: Accurate seismic interpretation minimizes drilling risks by avoiding dry wells and locating high-potential zones. Field Development Optimization: Enhanced understanding of reservoir connectivity ensures efficient placement of wells and infrastructure.

9.0 Reservoir Modeling Tools

Key Software for Reservoir Simulation: Petrel (Schlumberger): Capabilities: Builds static and dynamic reservoir models using seismic, well logs, and production data. Integrates geophysics, geology, and reservoir engineering for comprehensive field analysis. Application in Obagi: Useful for generating 3D geological models of Agbada reservoirs. Helps delineate fault blocks and stratigraphic traps, optimizing gas production. Eclipse (Schlumberger):

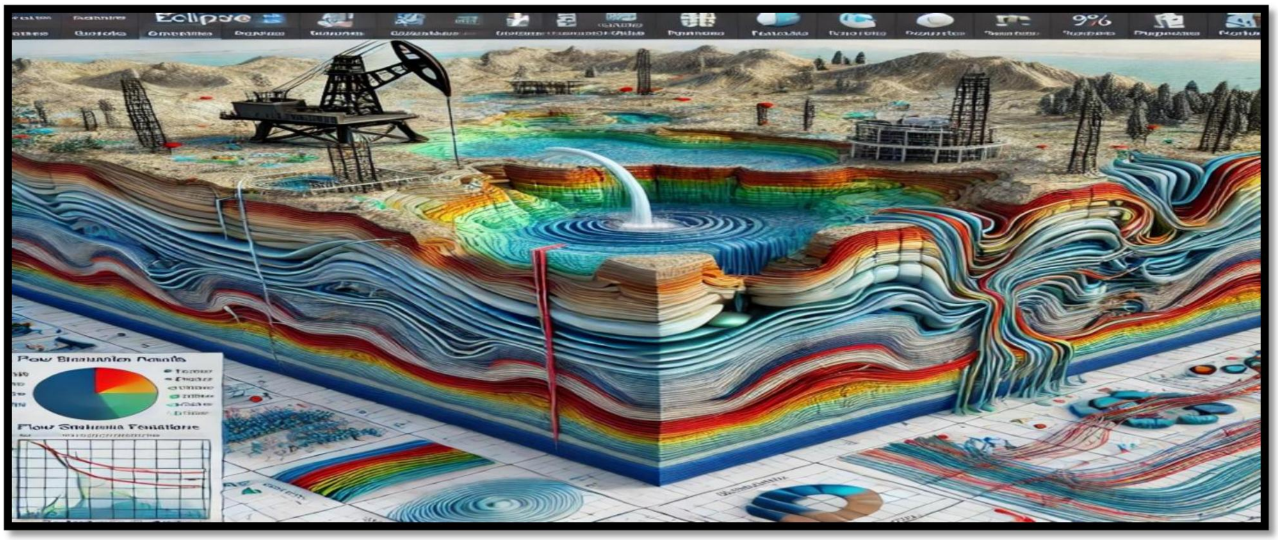

Figure 1: Reservoir Model Using Eclipse by Schlumberger

A detailed illustration of a reservoir model using Eclipse by Schlumberger (Figure 1), showing advanced features such as 3D geological layers, fault lines, well placements, and fluid flow simulations. The diagram also includes key elements like pressure-volume-temperature (PVT) data, fluid properties, and production forecasts. It highlights the software's capabilities for modelling reservoirs with oil, gas, and water phases, along with colour-coded fluid flow paths and pressure gradients (Onwuka & James.,2019).

Capabilities: Specialized for dynamic reservoir simulation, including gas, oil, and water flow behaviour. Models' reservoir drive mechanisms like gas expansion and water influx. Application in Obagi: Ideal for simulating gas cycling and predicting pressure behaviour under various recovery strategies. CMG Suite Computer Modelling Group): Modules: GEM: Focused on gas-condensate reservoirs and enhanced gas recovery processes. IMEX: Black oil simulator for primary and secondary recovery scenarios. Application in Obagi: GEM can simulate gas cycling and compositional changes in the reservoir (Osagie & Akinmolade.,2020). T Navigator: Capabilities: Real-time simulation and visualization for faster decision-making. Application in Obagi: Can simulate production strategies for multi-reservoir systems in the OML 58 block. Workflow Using Modeling Tools Input Data: Gather seismic, well logs, core data, and production history. Static Model: Construct a detailed geological framework (structural maps, facies distribution). Dynamic Simulation: Calibrate flow models using historical production data. Simulate scenarios like gas cycling or infill drilling. Sand Control in the Obagi Field Challenges with Sand Production (Thomas &Alabi.,2021). Unconsolidated Sands: Deltaic sands in the Agbada Formation are prone to sand production. Impact: Erosion of downhole equipment, reduction in productivity, and plugging of surface facilities. Solutions. Gravel Packing: Description: Place gravel between the wellbore and screen to filter sand. Advantages: Prevents sand migration while allowing hydrocarbon flow. Effective for high-permeability reservoirs like the Obagi sands. Sand Screens: Description: Perforated liners or slotted pipes placed in the wellbore. Types: Wire-wrapped screens. Expandable screens for tighter formations. Usage in

Obagi: Helps reduce sand production from highly unconsolidated zones. Chemical Consolidation: Description: Injecting resin into the formation to bind sand grains. Advantages: Maintains permeability while stabilizing the sand. Limitations: Costly and time-consuming, reserved for severe cases. Sand Monitoring Systems: Real-time tools (acoustic sensors) detect and quantify sand production to adjust operations (Udo & Chike.,2022).

Gas Cycling for Enhanced Recovery: What is Gas Cycling? Definition: Injection of produced gas back into the reservoir to maintain pressure and optimize recovery. Purpose in Obagi: Prevents retrograde condensation in gas-condensate reservoirs. Enhances the recovery of liquid hydrocarbons (condensates). Steps in Gas Cycling Implementation: Reservoir Simulation: Use tools like Eclipse GEM to model the effect of gas injection on pressure and recovery. Gas Compression: Install compressors to reinject produced gas at high pressure. Injection Design: Determine optimal injection rates and locations using reservoir models. Monitoring and Optimization: Use real-time data to adjust injection volumes and assess performance. Advantages, sustains reservoir pressure and delays liquid dropout. Increases the recovery factor for both gas and condensates. Challenges, High costs for gas compression and reinjection facilities. Risk of reservoir souring (e.g., H_2S formation) if impurities are present in the injected gas. Example Application in Obagi Field, Sand Control: Sand screens with real-time monitoring were deployed in wells with high sand production risk. Proactive gravel packing reduced erosion in high-rate gas wells. Gas Cycling: Gas was compressed and reinjected into central gas reservoirs to maintain pressure above the dew point. Simulation results showed a 15–20% increase in condensate recovery over primary depletion. Next Steps for Obagi Development. Run Pilot Studies: Test gas cycling in one or two wells before full-scale implementation. Sand Control Optimization: Deploy a combination of gravel packs and chemical stabilization for problematic zones. Dynamic Modeling Updates: Continuously update reservoir models with production data to refine recovery strategies.

Figure 2: Advanced Reservoir Modeling Tools and Software for Reservoir Simulation

A detailed illustration showcasing various advanced reservoir modelling tools and software for reservoir simulation (Figure 2). It includes 3D reservoir models, geological layers, fault lines, wells, and fluid properties, along with graphs and charts displaying simulation results, pressure-volume-temperature (PVT) data, and flow rates. The tools represented include popular software such as Petrel, Eclipse, and CMG, which are commonly used for geological modelling, reservoir simulation, and fluid dynamics analysis.

10.0 Simulation Workflow for Gas Cycling and Sand Control

Step 1: Data Collection and Preparation: Reservoir Data: Seismic interpretation to map structural traps. Core data to analyze porosity, permeability, and lithology. PVT data to understand fluid properties (e.g., dew point, gas-condensate ratio). Production Data: Historical rates for gas, oil, and water production. Well, pressure and temperature profiles. Sand Production Data: Logs or field measurements of sand quantities. Step 2: Build a Static Model, Geological Framework: Import seismic and well data into software (e.g., Petrel). Define fault networks, reservoir boundaries, and layering. Petrophysical Properties: Assign porosity, permeability, and saturation based on well-log data (Williams & Olayiwola.,2017). Use facies modelling to map sand-shale distribution. Step 3: Dynamic Reservoir Simulation: Simulation Setup: Use software like Eclipse GEM or CMG IMEX. Input PVT data for gas-condensate and oil phases. Gas Cycling Simulation: Set up injector wells for reinjection of produced gas. Optimize injection rates to maintain pressure above the dew point. Sand Control Simulation: Apply sand production models to identify critical zones. Simulate well-completion designs (e.g., gravel packs or screens). Step 4: Calibration and History Matching, Adjust the simulation model to match historical production data. Refine parameters like relative permeability, capillary pressures, and fault transmissibility. Step 5: Predictive Scenarios, Run scenarios for: Primary depletion: No reinjection. Gas cycling: Reinjection at varying rates and pressures. Enhanced sand control: Different well completions.

11.0 Interpreting Production Data

Key Metrics to Analyze, Gas-Oil Ratio (GOR): Helps identify depletion trends or condensate dropout. Sudden changes may indicate reservoir compartmentalization. Pressure Decline: Monitored using reservoir pressure surveys. A rapid decline suggests poor connectivity or undersized gas cycling rates. Sand Production Rates: Real-time monitoring tools provide data on sand influx. Analyze spikes to correlate with production events (e.g., choke adjustments). Diagnostic Plots: Material Balance Plots: Estimate original gas in place (OGIP) and drive mechanisms. Decline Curve Analysis: Forecast future production using Arps' equations. Assess the impact of gas cycling on decline rates. Pressure vs. Cumulative Production: Determine reservoir connectivity and aquifer support.

12.0 Addressing Challenges

Challenge 1: Optimizing Gas Cycling, Solution: Use compositional simulations to test injection pressures above the dew point. Evaluate the impact of cycling on condensate recovery using sensitivity analysis. Expected Results: Stabilized reservoir pressure. Increased recovery of condensates and delayed gas cap expansion. Challenge 2: Controlling Sand Production, Solution: Incorporate sand production models in reservoir simulation software. Select completion designs (e.g., gravel packs) based on simulated sand influx zones. Expected Results: Reduced downtime from equipment erosion. Sustained production rates without significant sanding issues.

13.0 Workflow Using Petrel and Eclipse

Data Preparation in Petrel. Load Geological Data: Import seismic data (time or depth-migrated) to define structural frameworks. Import well logs for lithology, porosity, and permeability. Correlate stratigraphic layers to identify key formations (e.g., Agbada sands). Fault Modeling: Use seismic interpretation to map growth faults and roll-over anticlines. Validate fault-seal potential for hydrocarbon trapping. Reservoir Zonation: Divide the reservoir into zones based on facies (sand vs. shale distribution). Create property maps for porosity, permeability, and saturation. Static Modeling: Build a 3D grid to capture the reservoir's structural and stratigraphic details. Assign rock and fluid properties to grid cells.

Export to Eclipse, Prepare Dynamic Inputs: Export the static model from Petrel to Eclipse. Define PVT tables for gas-condensate fluids (from lab analysis or field data). Add relative permeability and capillary pressure curves. Set Up Simulation: Gas Cycling: Specify injection wells, rates, and pressures. Model gas reinjection above the dew point to prevent retrograde condensation. Sand Control: Implement sand production models (e.g., sanding thresholds based on stress). Add gravel pack or screen completions in selected wells. Boundary Conditions: Include aquifer support or external boundary pressure gradients. Simulate faults as sealing or transmissible, based on petrophysical data.

14.0 History Matching

Input Historical Production Data: Use actual gas, oil, water rates, and bottomhole pressures from the Obagi Field. Calibration: Adjust model parameters (e.g., permeability, relative permeability) until the simulation matches historical trends. Ensure alignment of pressure-decline curves and GOR trends. Run Predictive Simulations. Base Case: Simulate primary depletion without gas cycling. Gas Cycling Case: Test different injection pressures and rates. Optimize reinjection volumes to maintain reservoir pressure. Sand Production Mitigation: Evaluate different well completions: Open Hole: High risk of sanding. Gravel Packed: Simulate reduced sanding impact. Screen Completion: Model efficiency under varying production rates. Interpreting Production Data. Key Indicators to Monitor. GOR Trends: Stable GOR: Indicates effective gas cycling and pressure maintenance. Rising GOR: May suggest breakthrough of injected gas. Pressure Decline: Monitor pressure surveys to evaluate the effectiveness of gas cycling. Sand Production: Analyze data from sand monitors to correlate with production rates. Identify wells requiring completion adjustments. Diagnostic Plots. GOR vs. Time: Identifies the impact of gas cycling. Pressure vs. Cumulative Production: Evaluates reservoir connectivity. Sand Rate vs. Flow Rate: Detects sanding thresholds and optimization opportunities. Example Outputs and Insights. Gas Cycling Results: Predict recovery factor improvements: e.g., a 10–20% increase in condensates. Delayed dew-point pressure drops. Sand Control Results: Gravel packing reduced sand influx by 70–90%, enabling stable production rates.

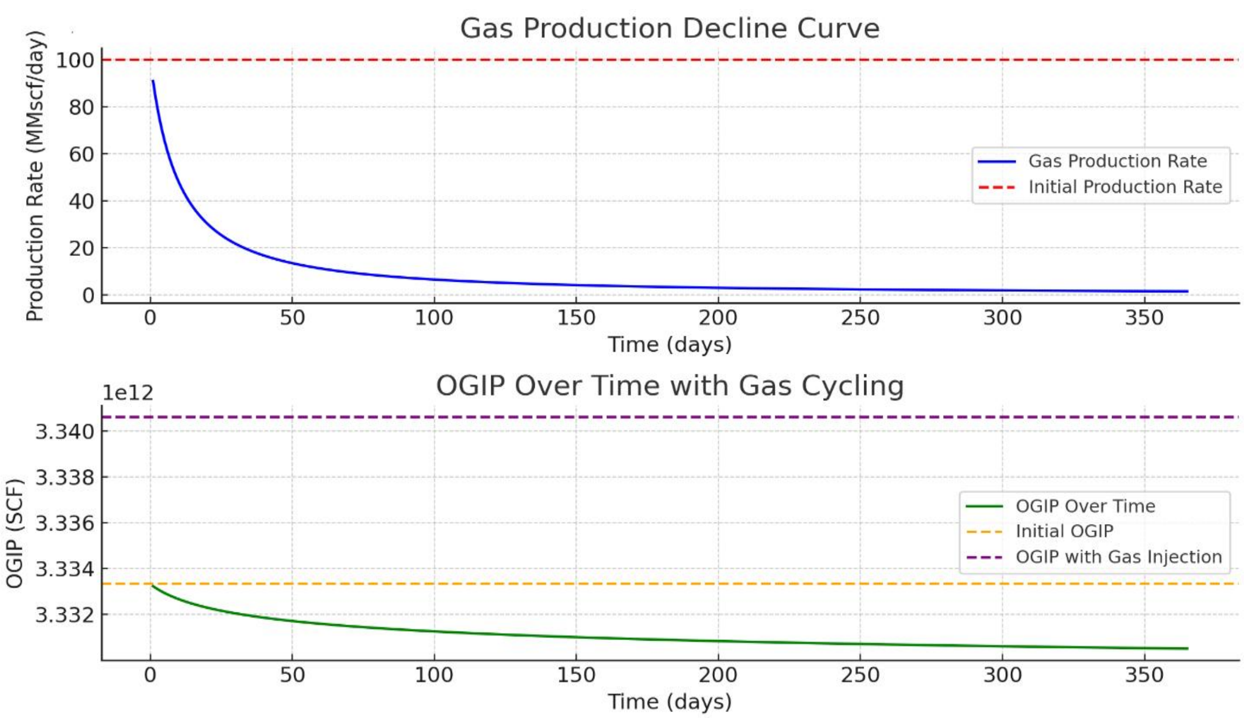

Figure 3: The graphical representation of the models and gas volume in place for the Obagi OML 58 field

Gas Production Decline Curve: The blue curve represents the gas production rate over one year, following a hyperbolic decline (Figure 3). The production rate starts at 100 MMscf/day and declines to 22.3 MMscf/day by the end of the year. The red dashed line shows the initial production rate of 100 MMscf/day. OGIP Over Time with Gas Cycling: The green curve represents the Original Gas in Place (OGIP) over time as production continues, with a gradual decrease in OGIP due to gas production. The orange dashed line indicates the initial OGIP value of 333.33 Bcf. The purple dashed line shows the updated OGIP of 340.63 Bcf after accounting for the gas injection. The gas injection increases the recoverable gas volume, maintaining pressure and extending production life. These models illustrate how gas production decreases over time and how gas cycling can enhance the recoverable reserves in a gas reservoir. The decline curve helps forecast future production rates, while the gas injection model indicates how external factors, like gas cycling, can affect the total volume of gas in place

15.0 Gas Production Decline Curve (Top Plot)

This plot illustrates the decline in gas production over time using the Arps hyperbolic decline model. The graph shows how the production rate decreases as the field continues to produce gas, which is typical in most gas reservoirs. X-axis (Time): This represents the number of days, spanning one year (365 days). Y-axis (Gas Production Rate): This shows the gas production rate in MMscf/day (millions of standard cubic feet per day). Initial Production Rate: The red dashed line at 100 MMscf/day represents the initial gas production rate. This is the amount of gas the field is capable of producing when it is first brought online. Decline Curve: The blue curve represents the production decline. According to the Arps' model, the production rate follows a hyperbolic decline. Initially, production decreases rapidly, and as the reservoir pressure drops and gas is extracted, the rate of decline slows down. The production rate at the end of the year is predicted to be around 22.3 MMscf/day, a decrease from the starting rate of 100 MMscf/day. This is typical for gas fields, where production declines over time unless enhanced recovery methods (like gas cycling) are employed.

16.0 OGIP Over Time with Gas Cycling (Bottom Plot)

The second plot shows how the Original Gas in Place (OGIP) in the reservoir changes over time as gas is produced and injected into the reservoir for pressure maintenance. X-axis (Time): Same as above, representing days over one year. Y-axis (OGIP): This represents the volume of gas in the reservoir, measured in standard cubic feet (SCF). The scale is in billions of cubic feet (Bcf). Initial OGIP (orange dashed line): The OGIP at the start of production is 333.33 Bcf, as calculated earlier. This is the total volume of gas originally in the reservoir before any production takes place. Cumulative Gas Production (green curve): The green curve represents the OGIP over time, showing how the gas volume decreases as the gas is produced. As gas is extracted from the reservoir, the available volume of gas in the field reduces. Over the first year, the cumulative volume of gas produced (shown by the decline in the green curve) reduces the total OGIP in the reservoir. This curve would continue to drop as more gas is extracted over the years. Gas Injection Impact (purple dashed line): The purple dashed line represents the OGIP after gas injection. Gas injection is part of the gas cycling process, where gas is re-injected into the reservoir to maintain pressure and enhance recovery. As a result, the OGIP increases by 7.3 Bcf (calculated previously), bringing the total OGIP to 340.63 Bcf. This injection helps maintain the pressure in the reservoir and extend the life of the field. Gas cycling is particularly important for maintaining gas production rates and preventing retrograde condensation, where gas could condense back into liquid form due to low pressure. By injecting gas, the operator can avoid this issue and increase the total recoverable reserves.

Production Decline: Gas production declines significantly over time without intervention. In this case, after one year, the production rate drops from 100 MMscf/day to 22.3 MMscf/day due to reservoir pressure depletion and natural decline. Gas Cycling Effect: The gas cycling model, shown in the second plot, illustrates how re-injecting gas into the reservoir can increase the OGIP. This is a common strategy to prolong the life of the field, maintain production levels, and increase the overall volume of gas that can be recovered from the reservoir. Recovery Potential: The graph clearly shows that by using gas cycling, more gas can be recovered (as shown by the increase in OGIP), which is essential for fields like Obagi, where gas injection is a standard practice for maintaining pressure and optimizing production over the long term. This detailed representation highlights how gas fields typically behave over time and the importance of technologies like gas cycling to improve recovery and extend the productive life of the reservoir. To analyze the economic aspect of gas production based on the price of natural gas in the international market, we can model the revenue generated from gas production over time using the production rate and fluctuating gas prices. Here's how to approach this:

17.0 Steps for Modelling the Economic Impact:

Define Gas Price: We'll assume a fluctuating price for natural gas in the international market. As of 2024, the price of natural gas can range anywhere from $3 to $10 per MMBtu depending on market conditions (prices can vary by region, season, and other factors). For simplicity, we can assume a base price of $5 per MMBtu for this calculation. Conversion from MMscf to MMBtu: Natural gas is often sold by the MMBtu (Million British Thermal Units). To convert from MMscf (Million Standard Cubic Feet) to MMBtu, we use the fact that 1 MMscf of natural gas is approximately equal to 1 MMBtu, assuming typical gas composition. Revenue Calculation: Multiply the production rate (in MMscf/day) by the gas price (in $/MMBtu) to calculate the daily revenue. Then, integrate this over time to estimate the revenue over a specific period (e.g., one year). Adjust for Decline: The production rate declines over time as shown in the earlier decline curve, so we need to account for this decline in our revenue model. Gas Injection Consideration: Gas injection can help maintain production rates, thereby potentially increasing revenue.

We assume:

Initial gas price: $5 per MMBtu

Initial production rate: 100 MMscf/day

Decline rate: Hyperbolic decline model with parameters b=0.8b = 0.8b=0.8, D=0.1D = 0.1D=0.1

Production period: 365 days (1 year)

18.0 Revenue Calculation Over One Year: Using the production rate from the **decline curve model**, we can calculate the **daily revenue** and then integrate it over the year.

Formula:

Revenue(t)=Production Rate(t)×Gas Price\text{Revenue}(t) = \text{Production Rate}(t) \times \text{Gas Price}Revenue(t)=Production Rate(t)×Gas Price

Where:

- **Production Rate** is q(t)=qi·(1+b·D·t)−1/bq(t) = q_i \cdot (1 + b \cdot D \cdot t)^{-1/b}q(t)=qi ·(1+b·D·t)−1/b
- **Gas Price** = $5/MMBtu

We now calculate the total revenue over one year.

Revenue Model Over Time: We'll calculate the daily revenue for each day of the year and then plot the total revenue for each day. We now generate a plot for this.

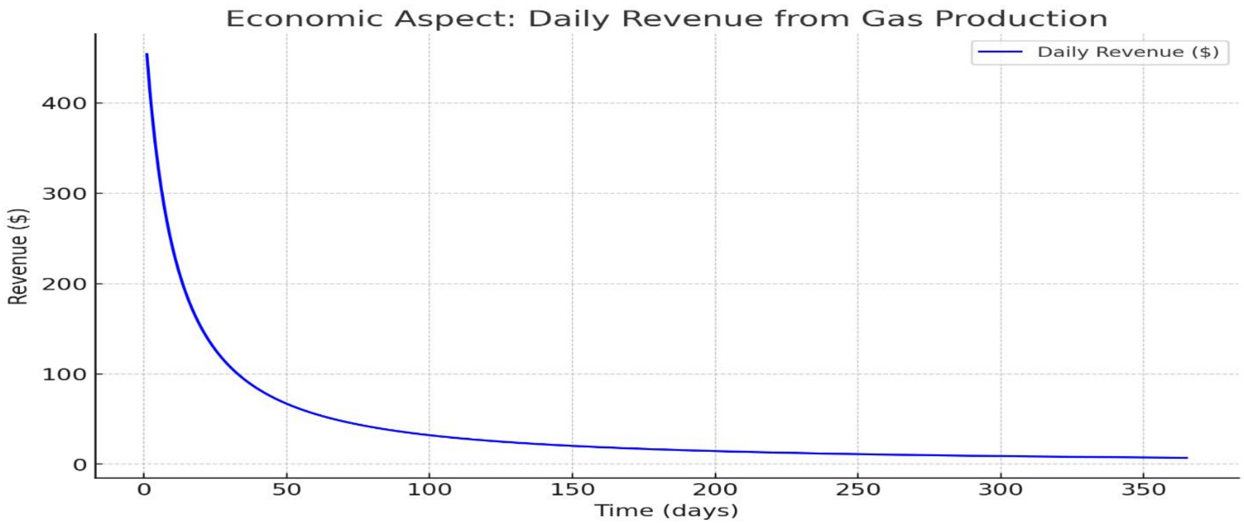

Figure 4: Daily Revenue from Gas Production

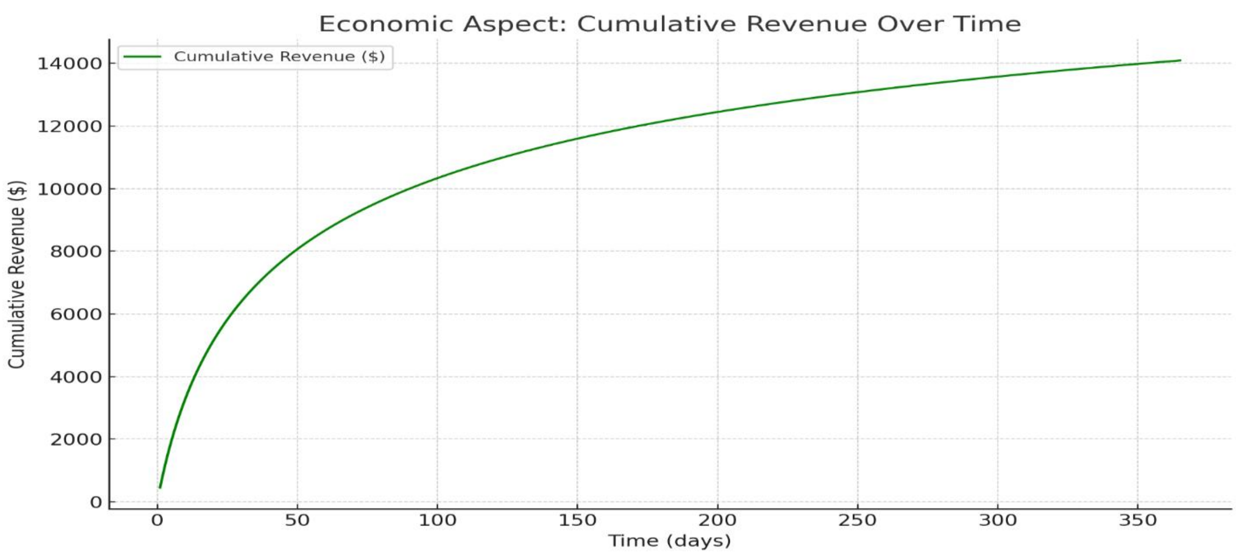

Figure 5: Cumulative Revenue over time

Daily Revenue (Figure 4). The blue curve shows the daily revenue generated from gas production over time. Initial Revenue: At the beginning of the year, with a production rate of 100 MMscf/day and a gas price of \$5/MMBtu, the daily revenue is \$500,000 (100 MMscf/day × \$5/MMBtu). Declining Revenue: As the production rate declines according to the hyperbolic decline model, the daily revenue also drops. After one year, the production rate decreases to about 22.3 MMscf/day, which leads to a corresponding drop in daily revenue to approximately \$111,500. This decline in revenue is typical for natural gas fields where production decreases over time unless additional recovery techniques like gas cycling are applied.

Cumulative Revenue (Figure 5). The green curve shows the cumulative revenue accumulated over the year. Initially, the cumulative revenue grows rapidly as the production rate is high. Over time, as the production rate decreases, the rate of increase in cumulative revenue slows down. At the end of one year, the total cumulative revenue would be the sum of the declining daily revenues. This demonstrates how the total revenue increases over time but slows as production declines. In real-world scenarios, enhanced recovery techniques (like gas injection) could help extend the field's productive life and mitigate the decline, increasing cumulative revenue.

19.0 Economic Insights:

Initial High Revenue: When production rates are high, the field generates significant revenue, particularly at the beginning of production. Revenue Decline: Over time, without interventions, the production rate (and revenue) decreases significantly, which impacts the financial sustainability of the field. Gas Injection: By maintaining production through gas cycling (re-injection), operators can potentially extend the period of high production, thus sustaining higher revenue for longer periods.

Conclusion

This study presents a comprehensive assessment of the natural gas resources in the geological formations of the Obagi OML 58 oil and gas fields, integrating geological, reservoir, and economic evaluations to provide an in-depth understanding of the field's potential. The geological and petrophysical analysis of the Obagi reservoir revealed a complex subsurface structure with varied porosity and permeability profiles, necessitating advanced reservoir modelling techniques to estimate gas volumes and production capacities accurately. The integration of seismic, well-log, and core data has enabled a refined geological model that serves as the foundation for production forecasting and enhanced recovery strategies. The application of dynamic reservoir simulation and decline curve analysis has provided valuable insights into the production behaviour of the Obagi OML 58 gas fields. Forecasting future production rates, incorporating gas cycling and other enhanced recovery techniques, suggests a significant potential for maximizing gas recovery and extending the productive life of the field. Sensitivity analysis further identified critical factors, such as gas price fluctuations, operational costs, and production rates, which could impact the long-term viability of the field. Under the assumption of a $5 per MMBtu gas price, the field exhibits a favourable revenue outlook, with considerable potential for sustained financial returns, although market fluctuations and operational challenges could influence profitability over time.

The economic analysis, utilizing discounted cash flow (DCF) models and net present value (NPV) calculations, demonstrated that, under current assumptions, the Obagi OML 58 field has the potential to generate substantial revenue. The NPV for the field indicates a positive financial outlook, provided that production continues at optimal rates. However, the profitability of the field is closely tied to the evolution of global natural gas prices and the successful implementation of enhanced recovery methods (Wosu *et al*.,2023b). For example, a modest 5% increase in gas prices would significantly improve revenue projections, while a 15% reduction in operating costs could boost profit margins further. The break-even analysis conducted within this study reveals that the Obagi OML 58 field has a relatively quick payback period, reinforcing its attractiveness as an investment opportunity in the current energy market. However, as production rates decline and operational costs increase over time, the field's profitability will require careful management and possibly the integration of additional enhanced recovery techniques. The sensitivity analysis conducted in this study also highlighted the importance of continuously monitoring market trends and adapting production strategies to ensure long-term financial success.

This work provides valuable insights into effective strategies for gas resource management in the context of evolving market dynamics. It underscores the need for integrated decision-making frameworks that balance geological potential with economic realities to ensure the long-term sustainability and profitability of natural gas fields in the region.

Declarations

Data availability

The datasets generated during and/or analysed during the current study are available from the corresponding author upon reasonable request.

Ethics approval and consent to participate

Not applicable

Competing Interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Authors contributions

E. E. M – *Drafting of the article, Data sharing, technical support, Funding acquisition, experimental work, analysis, interpretation of data and materials support*

N. H. A- *Conceptualization, methodology, acquisition of data, funding acquisition, experimental work, supervision, drafting of article and final approval.*

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