PRODUCTION OPTIMIZATION IN MATURE, HIGH-WATER-CUT NIGER DELTA RESERVOIRS

BY

ONWUBOLU ESUMEL RAYMOND

MAT. NO: PG/ENG2216120

DEPARTMENT OF PETROLEUM ENGINEERING

FACULTY OF ENGINEERING

UNIVERSITY OF BENIN

BENIN CITY

MARCH 2026

PRODUCTION OPTIMIZATION IN MATURE, HIGH-WATER-CUT NIGER DELTA RESERVOIRS

BY

ONWUBOLU ESUMEL

MAT NO: PG/ENG2216120

A PROJECT THESIS SUBMITTED TO THE DEPARTMENT OF PETROLEUM ENGINEERING IN PARTIAL FUFILMENT OF THE REQUIRMENT FOR THE AWARD OF POSTGRADUATE DEGREE IN PETROLEUM ENGINEERING DEPARTMENT

UNIVERSITY OF BENIN

BENIN CITY

MARCH, 2026

I hereby certify that the report presented represents the true project work carried out by Mr. Onwubolu Esumel Raymond

……………………… …………

ENGR. DR. IKPONMWOSA OHENHE DATE

(Project Supervisor)

……………………… ………………

ENGR. DR. IKPONMWOSA OHENHEN DATE

(Head of Department/Project Coordinator)

……………………… ………………

PROF. S.O ISEHUNWA DATE

(External Supervisor)

DEDICATION

This project work is dedicated to God Almighty for his grace upon me and to my wife Mrs. Onwubolu Abgail for her words of encouragement

ACKNOWLEDGEMENT

I wish to express my profound gratitude to amiable supervisor ENGR. DR. Ikponmwosa Ohenhen for his encouragement and support to me during the preparation of this work.

I must also be grateful to my distinguished lecturers, Prof. K. Adewale, Prof. Olafuyi, Engr. Dr. I. Ohenhen, for their encouragement.

Special thanks to all my friends and colleagues who directly or indirectly contributed to the success of this project.

Contents

1.0 Background to the study

Mature oil reservoirs are frequently afflicted by sharply increasing water cuts, which escalate production costs, reduce profit margins, and accelerate field abandonment. Water cut measures the volume of produced water as a function of total fluids; in mature fields, those can be north of 90%. According to Alisheva et al., 2025, high water cut can have a severe economic impact on field economics often requiring costly separation, handling and disposal processes (e.g. produced water reinjection). In oil and gas, production optimization is a multi-disciplinary approach that includes a range of methods corresponding to increasing hydrocarbon recovery, reducing costs, ensuring operational constraints are considered, and extending the productive lifespan of the field. It spans three key domains:

- Reservoir Management – involves sound optimization practices (monitoring reservoir performance, visualizing fluid distributions and influencing fluid movement using techniques like water or gas injection to pressure maintenance or sweep uplift)
- Wellbore optimization – Maintaining integrity and function (scaling, flow inefficiencies, optimizing completion designs or artificial lift systems)
- Surface Facilities & Network Efficiency: Enhancing the capacity and reliability of separators, pipelines, pumps, and other components to reduce bottlenecks and process fluids efficiently

The Niger Delta is the source of about two million barrels per day of the crude oil that makes Nigeria Africa's top producer. Many ecosystems in the area are fecund and in sharp decline from decades of spills, vandalism, and aging infrastructure. Most of the oilfields are more than 30 years old and are depleting. In particular, produced water in Niger Delta fields can exceed 50% — up to 95 % of the total fluid extraction (Nwokoma and Dagde, 2024) mainly during secondary or tertiary production phases. The disposal standards are quite strict in case of produced water but the conventional produced water treatment techniques do not guarantee its complete removal and typical treated TDS, COD and oil & grease levels often further exceed specified regulatory thresholds (Nwokoma and Dagde, 2024).

Production optimization in mature, high-water-cut Niger Delta reservoirs entails:

- Targeting and mitigating specific challenges like excessive water production.
- Evaluating interventions (e.g., shut-off, artificial lift) through integrated modeling to ensure operational feasibility.
- Extending field life while enhancing economic returns and reducing environmental risks.

In field case scenarios, optimization techniques have been utilized to improve productivity from the reservoir, reduce water cut and enhance profitability (economics). Joseph and James (2021) conducted optimization study on the Kalama reservoir in the Niger-delta area. Investigations revealed that multi-layered flows, high permeability streaks and channeling behind casing were the main sources of the high water cut.

Diagnostic plots assisted in identifying problems, and work overs were recommended as a remediation method for cementation. The diagnosis and management of excessive water production in oil wells in the Niger Delta oilfields are examined by Nmegbu et al., 2020. The original water-cut of 60% for the first well, NDZ_A, was lowered to 0.3% with a 412 Bopd increase in production, while the initial water-cut of 43% for the second well, NKZ_B, was lowered to 0% with a 968 Bopd increase in output.

To identify the optimization gap in the production process analytically, the following should be considered:

- Utilizing reservoir models and performance data to compare present production to technical potential of the reservoir, production and surface facilities.
- Determining infrastructure or operational restrictions (e.g., diminishing reservoir pressure, sub-surface and surface facility limitations).
- Creating and ranking improvement levers, such as investing in new wells or infrastructure modifications or improving the performance of current wells.

To combat high water cut challenges, in production optimization, several strategies have been utilized in the oil and gas industry.

1. Mechanical/chemical interventions: By improving sweep efficiency and rerouting flow (Alisheva et al., 2025), techniques such as water shut-off, polymer flooding, diversion wells, and low salinity water injection.
2. The goal of enhanced oil recovery (EOR) is to mobilize residual oil and increase recovery from the usual 20–40% to 30–60% or higher using tertiary techniques including CO_2 injection, gas injection, thermal techniques, and surfactants (Anderson et al., 2022).
3. Advanced modeling & description: Intelligent oilfield simulations, reservoir layer subdivision, high-resolution geological models, and flow topology mapping improve comprehension of the distribution of residual oil and direct efficient intervention.
4. Experimental approaches like thickened supercritical CO_2 flooding (showing up to 23% improved recovery) and ultrasonic stimulation (reducing viscosity significantly and modifying wettability) are emerging as promising innovation tools (Anderson et al., 2022)

1.1 Problem statement

High water cut is a common occurrence in mature oil reservoirs with a long production history, which presents serious obstacles to ongoing effective hydrocarbon recovery. The growing water production in these aging reservoir locations strains surface facilities and operating budgets in addition to lowering oil yield. Many mature reservoirs continue to operate below ideal levels despite a variety of production tactics because of inadequate reservoir management and a dearth of adaptive optimization techniques. The problems are itemized below:

1. High water cut ranging from 70-90% impairs productivity from the reservoir.
2. Low oil production from high water cut wells.
3. Increased operational cost of water handling, (separation, disposal and reuse) which affects the economics of the project.
4. Ineffective utilization of numerical simulation techniques in real time during production from such reservoirs, thus resulting in inefficient production optimization of the asset.
5. Inefficient production strategies: Conventional approaches may not consider the complex reservoir heterogeneity and fluid dynamics of the reservoir at late production time and high water cut conditions.

1.2 Aim and Objectives

The aim of this research is to conduct a robust production optimization study of a mature reservoir X in the Niger Delta area operating with a high water cut.

The specific objectives are:

1. Establish a base case scenario: This entails utilizing the production history of the wells in the reservoir and MBAL software to build a representative model of the Niger-Delta reservoir and simulate reservoir performance without artificial lift technology.
2. The model is calibrated by integrating MBAL, PROSPER and GAP for a holistic representation of the reservoir production systems.
3. Simulate the impact of implementing ESP and Gas lift in the selected wells for artificial lift.
4. Integrate PROSPER model with MBAL and GAP to identify improvement in production rates, pressure profile and system performance
5. Identify maximum operating conditions within set constraints of optimization parameters such as operating frequency, pump size, gas lift volumes and injection depths.
6. Perform comparative analysis of the base case scenario, with the ESP and the gas lift optimization scenarios in terms of oil production rate, water cut behavior, reservoir pressure profile, well performance and surface constraints.
7. Conduct economic analysis for all case scenarios based on NPV.

1.3 Scope of the research

Using numerical simulation and artificial lift techniques, this study compares the current (base case) production performance with two optimization scenarios involving Electric Submersible Pumps (ESP) and Gas Lift in order to optimize production of a mature onshore Niger Delta oil reservoir that is currently experiencing high water cut. The specific scope of the work includes:

- A mature conventional sandstone oil reservoir operating at water cut of over 70%.
- The modelling tools required for production optimization include MBAL for reservoir material balance modelling, PROSPER for wellbore performance and artificial lift systems and GAP for surface production modelling and full system integration

- This research will consider only ESP and Gas lift optimization artificial lift methods.
- Economic analysis is conducted for the base case and both artificial lift scenarios. NPV is the economic metric utilized, with operational costs considered.
- The data utilized for this study is production history, pressure history, PVT, well test data.

The study considers implementation of material balance and production system modelling, excluding geological modelling or 3D numerical simulation. Field scale implementation of the optimization is outside the scope of this research. While conducting economic analysis, uncertainties in oil price, and logistics incurred specific to Niger-Delta area like financial gifts and settlements of community, are not incorporated into the model. For gas lift optimization, for model simplicity, it was assumed that gas supply availability is not constrained by infrastructural limitations.

1.4 Relevance of the study

This study's practical, financial, and technological significance for the ongoing development and optimization of established oil fields in the Niger Delta—many of which are currently beset by high water cut and diminishing oil production—makes it relevant. This study provides field operators and engineers with useful information and resources as Nigeria looks to optimize oil recovery from its current assets in a financially responsible way.
The following points outline study relevance:

- This study provides a systematic approach to improving recovery by optimizing artificial lift strategies based on simulation-driven analysis.
- By comparing **ESP and gas lift** under field-specific conditions, the study aids operators in selecting the most suitable and cost-effective lift method**.**
- It highlights operational limits, design considerations, and performance differences of each method in a high-water-cut environment.
- The application of MBAL, PROSPER, and GAP demonstrates the value of integrated asset modeling, enabling better prediction of reservoir, well, and surface system performance.

- The study provides quantitative backing for production optimization decisions, helping engineers and managers justify capital investments in artificial lift or surface network upgrades.
- With Nigeria aiming to boost oil recovery and reduce dependence on new exploration, improving the performance of existing fields aligns with national energy and economic goals.

2.0 Literature review

Mature Reservoir / Mature Field is a reservoir or field whose production has reached its plateau (peak) and is in a state of prolonged decline, usually after producing more than 50% of its proven plus probable reserves, or with a production history of more than 20-25 years. Mature oil fields commonly experience increasing water cut and declining oil rates as reservoirs age. A stage of production where the produced fluids from wells contain a very high fraction of water (e.g., ≥ 80%), when oil output is dropping and water production (and water handling/separation/disposal) becomes a critical economic constraint.

High water cut is a major operational and economic challenge—it increases handling and disposal costs, reduces net hydrocarbon volumes, and often forces costly workovers or well shut-ins. This literature review synthesizes existing knowledge on diagnosing high water production, remedial actions, artificial lift selection and optimization, and full-field production network optimization, with emphasis on approaches applicable to Niger Delta reservoirs. Recent advances in digital tools, coupled modelling (reservoir–well–surface), and machine learning for surveillance and lift optimization are included. (Diagnosing and Controlling Excessive Water Production, 2024;)

Mature reservoirs account for more than 70% of global oil production today, and many of these fields are in their late life, facing production decline, increasing water cut, and rising operating costs (Andersen et al., 2022; Xue et al., 2023). Xue et al. (2023) stress that the high-water-cut stage still holds considerable recoverable reserves and that delaying field abandonment by even a few years can yield significant economic returns.

Optimization is not just a technical exercise — it is a strategic imperative for operators because it directly affects profitability, safety, and ultimate recovery. Andersen et al. (2022**)** highlighted that optimization in high-water-cut mature reservoirs is crucial to maintain economic viability, manage produced water, and sustain production.

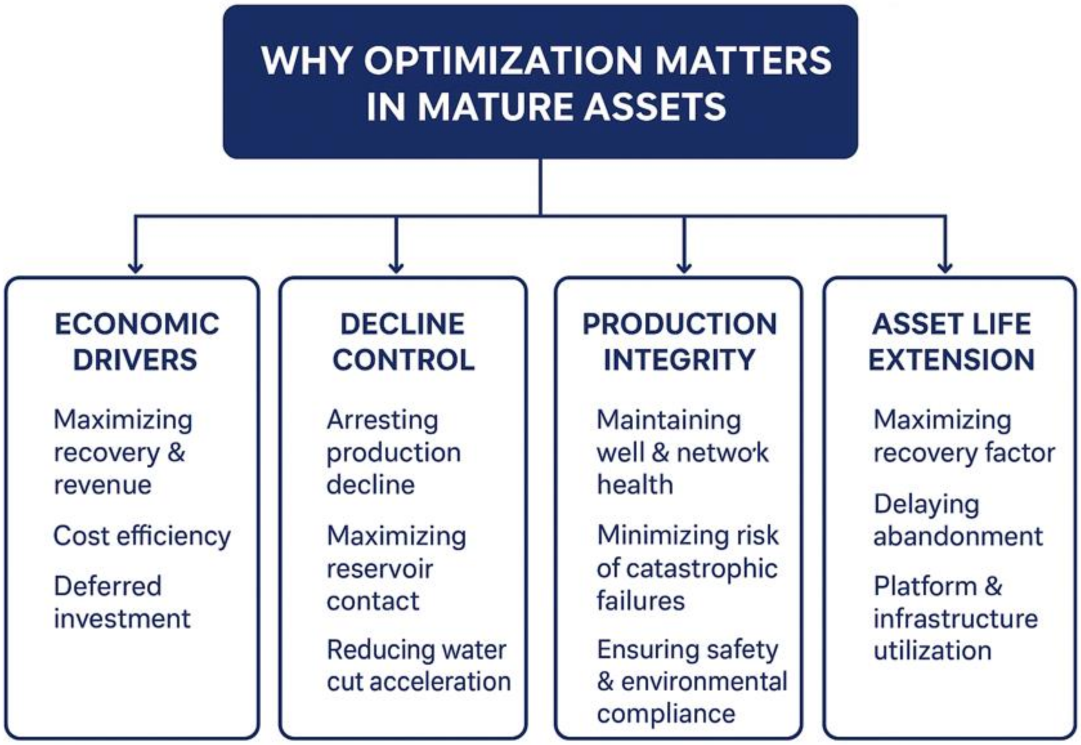


Figure 2.1: Importance of optimization in mature oil reservoirs

The key reasons are summarized below:

1. Economic Drivers

- Maximizing Recovery & Revenue: Mature assets often have significant remaining oil in place (20–40% OOIP still unrecovered even after secondary recovery). Production optimization unlocks additional barrels without new major capital expenditure.
- Cost Efficiency: Late-life fields face increasing lifting costs per barrel due to higher water handling, energy consumption, and maintenance needs. Optimizing well settings, choke positions, and surface network configurations minimizes operating costs.
- Deferred Investment: Through careful optimization, operators can delay expensive EOR projects or infill drilling until economics are favorable, improving field Net Present Value (NPV).
- Cash Flow Stability: Smoothing decline curves and mitigating production downtime help maintain predictable cash flows that fund other capital projects.

2. Decline Control

- Arresting Production Decline: Production optimization slows the natural decline rate by balancing well drawdowns, re-allocating production/injection, and improving sweep efficiency.
- Maximizing Reservoir Contact: Techniques like selective recompletion, reperforation, and smart well control optimize reservoir drainage patterns and reduce bypassed oil.
- Reducing Water Cut Acceleration: Through conformance control and optimized injection profiles, operators can limit early water breakthrough and extend the "economic oil window."

3. Production Integrity

- Maintaining Well & Network Health: High water production accelerates corrosion, scaling, and equipment failures. Optimization includes monitoring and mitigating these risks through better chemical treatment schedules and flow assurance planning.
- Minimizing Risk of Catastrophic Failures: Controlling drawdown reduces sand production, fines migration, and mechanical stresses on completions, prolonging equipment life.
- Ensuring Safety & Environmental Compliance: Lowering excessive water production reduces produced water handling volumes, disposal requirements, and environmental exposure.

4. Asset Life Extension

- Maximizing Recovery Factor: Late-life optimization adds incremental recovery by mobilizing unswept zones, improving areal and vertical sweep efficiency.
- Delaying Abandonment: Every additional barrel recovered profitably pushes abandonment further into the future, spreading abandonment liability and improving overall field economics.
- Platform and Infrastructure Utilization: Existing facilities can be leveraged fully, making incremental production more profitable compared to greenfield developments.

- Preparing for EOR: Optimized waterflood or well patterns set a better foundation for tertiary recovery projects, such as polymer or surfactant flooding, by providing balanced injection/production systems.

2.1 Niger Delta Reservoir

The Niger Delta, located in the southeastern part of Nigeria, is one of the largest and most significant oil-producing regions in Africa. The delta is characterized by a complex system of geological formations, which include a variety of reservoirs with different properties, ranging from shallow to deep reservoirs, and from sandstone to carbonate formations.

The Niger Delta is home to some of the largest and most mature oil fields in the world, and it has been a major contributor to global oil production for several decades. The Niger Delta comprises a thick clastic deltaic succession characterized by stacked channel sands, frequent shale barriers, and strong aquifer support in many reservoirs. Heterogeneity, variable permeability contrast, and active water drive are common features that control water encroachment and channeling (Kingue, 2025; Hydrogeology of Eastern Niger Delta, 2019). Regional studies emphasize strong natural aquifers and near-surface groundwater connectivity affecting produced water behavior and disposal considerations (Kingue, 2025; SCIRP review, 2019).

These reservoirs typically exhibit a range of reservoir types that have undergone significant pressure depletion and water production over time, especially in the mature fields that have been in operation for several decades. Given the age of these reservoirs, optimizing production is crucial for extending the life of the fields and maximizing economic returns.

2.2 Characteristics of Niger Delta Reservoirs

Niger Delta oil reservoirs are typically classified as *mature* reservoirs, meaning they have been in production for an extended period, often 30 years or more. The main characteristics of these reservoirs include:

- **Complex Geology**: The Niger Delta is an area of active sedimentary deposition, which results in a highly heterogeneous reservoir structure. Reservoirs are typically made up of *deltaic* deposits, including sandstones, shales, and siltstones, with intricate layering and varying porosity/permeability characteristics. These characteristics make reservoir modeling and optimization complex.

- **High Water Production**: As these reservoirs age, water production tends to increase, often because of the implementation of secondary recovery techniques like water flooding, or due to natural aquifer influx and water breakthrough. The increase in water production reduces oil recovery efficiency and increases operational costs.
- **High Decline Rates**: Niger Delta reservoirs typically experience high production decline rates, particularly once the reservoir pressure drops and natural drive mechanisms (such as gas or water drive) become less effective. This decline in production rates presents a challenge for operators seeking to maintain production levels over time.
- **Hydrocarbon Type**: The Niger Delta produces both light and medium crude oils, with a relatively high API gravity. However, as the reservoirs mature, there is an increasing reliance on tertiary recovery methods (like enhanced oil recovery or EOR) to extract remaining hydrocarbons.

2.3 Why Niger Delta Reservoirs Are Candidates for Production Optimization

The need for production optimization in Niger Delta reservoirs arises from a combination of factors related to the age and declining performance of these fields, as well as the economic importance of the region's oil reserves. Here are the primary reasons why Niger Delta reservoirs are prime candidates for optimization:

2.3.1 Declining Production Rates

As the reservoirs mature, natural reservoir pressure and drive mechanisms decrease, leading to a significant drop in production rates. This often results in reduced well productivity, making it harder for operators to maintain economic output. Without optimization, these fields can experience steep declines in production. Therefore, optimizing recovery methods such as water flooding, gas injection, and enhanced oil recovery (EOR) techniques becomes essential to prolong the productive life of these reservoirs and maximize hydrocarbon recovery.

2.3.2 High Water Production

Water production in Niger Delta reservoirs, as previously discussed, significantly impacts overall reservoir performance. High water-to-oil ratios (WOR) complicate production, increase operational costs, and reduce oil recovery efficiency. Water handling, disposal, and treatment incur substantial costs. Therefore, optimizing water management through smart injection techniques, advanced monitoring systems, and selective water shut-off mechanisms is crucial for maintaining production and reducing water-related issues.

2.3.3 Increasing Operational Costs

As the reservoirs mature, the cost of maintaining and operating production facilities increases. These higher costs arise from the need for more intensive monitoring, frequent maintenance, and replacement of equipment due to wear from water production. Furthermore, there are significant expenses associated with managing water (e.g., water treatment, separation, and disposal) and maintaining reservoir pressure. Optimizing production allows for a more cost-effective operation, improving the economic viability of mature fields.

2.3.4 Enhancement of Oil Recovery (EOR) Potential

Mature reservoirs in the Niger Delta are prime candidates for Enhanced Oil Recovery (EOR) techniques, such as CO_2 injection, chemical flooding, and thermal recovery methods. The application of these techniques can improve recovery rates by reducing the mobility of water and increasing the sweep efficiency, particularly in reservoirs where water flooding alone is insufficient. EOR techniques are key to boosting reserves and extending the operational life of these reservoirs.

2.3.5 Changing Reservoir Conditions

As the reservoirs evolve over time, the geological and petrophysical properties change. Factors such as pressure depletion, water breakthrough, and changes in reservoir fluid characteristics (e.g., gas-oil ratio, water-oil ratio) all create the need for ongoing optimization. Real-time monitoring and updated reservoir simulation models are necessary to capture these changes and adjust production strategies accordingly.

2.3.6 Environmental and Regulatory Pressures

The Niger Delta region has been subject to increasing environmental and regulatory scrutiny, with growing concerns over oil spills, gas flaring, and water contamination. Optimizing production helps reduce environmental risks by improving efficiency, reducing waste, and minimizing the impact of operations. Regulatory compliance, particularly in terms of environmental standards and sustainability practices, is driving the need for more efficient, optimized operations.

2.3.7 Maximizing Return on Investment (ROI)

Given that oil reserves in the Niger Delta are finite, the pressure to maximize the return on investment becomes more pronounced as production declines. Effective optimization methods, such as the use of advanced technologies for monitoring, modeling, and EOR, ensure that oil recovery is maximized, and costs are controlled. This is critical for maintaining profitability as the reservoir enters a phase of diminishing returns.

2.4 Technologies for Production Optimization

To address the challenges posed by declining production and high water handling costs, several technologies have been implemented in Niger Delta reservoirs to optimize production:

- **Water Injection Management**: Advanced water injection systems, such as smart water flooding and targeted water shut-off methods, are used to improve reservoir pressure maintenance while reducing water production.

- **Reservoir Simulation Models**: These models help operators predict reservoir behavior under various production scenarios, enabling them to make informed decisions about well placement, injection strategies, and recovery techniques.

- **Enhanced Oil Recovery (EOR)**: Techniques such as CO_2 injection, polymer flooding, and chemical flooding are being deployed to recover stranded oil and increase recovery factors.

- **Real-Time Data Monitoring**: The use of downhole sensors and surface monitoring systems provides real-time data on reservoir conditions, allowing operators to make timely adjustments to production strategies.

- **Artificial Lift Systems**: In some mature reservoirs, advanced artificial lift systems, such as gas-lift or electric submersible pumps (ESPs), are employed to optimize production in wells with declining pressure.

Niger Delta reservoirs, particularly those that are mature, face a series of challenges that make production optimization critical. The combination of declining production rates, increasing water production, high operational costs, and environmental concerns demands an ongoing focus on optimization strategies. By implementing advanced technologies such as enhanced oil recovery techniques, real-time monitoring, and efficient water management, operators can extend the productive life of these reservoirs, improve recovery rates, and maximize the economic returns of oil fields in the Niger Delta.

Optimization efforts are not only important from a technical standpoint but are also essential from an economic and environmental perspective, ensuring that Niger Delta oil fields remain a viable resource in the long term.

2.5 Causes and Measurement of High Water Cut

Primary causes of high water cut discussed in the literature are aquifer influx, water coning from bottom aquifers under large drawdown, channeling through high-permeability streaks, fracture connectivity, and completion-related crossflow between layers. Accurate diagnosis is essential before applying permanent remedies; blind water shutoff frequently fails if the source of water is not correctly identified (Alaigba, 2024).

Measurement and surveillance techniques include conventional production data analysis (WOR, decline curves), pressure transient analysis, production logging tools (spinner, temperature, noise logs), tracer testing, and 4D seismic monitoring for large fields (Morris, 1999). These tools are complementary: for example, production logging is excellent at well-level source identification whereas 4D seismic tracks large-scale aquifer movement (Morris, 1999).

2.5.1 Reservoir Drive Mechanisms Leading to High Water Cut

High water cut production is a common challenge in mature oil reservoirs and is strongly influenced by the prevailing **reservoir drive mechanism**. The following mechanisms are typically associated with excessive water production:

1. Strong Water Drive Reservoirs

Water drive is a form of reservoir drive mechanism that involves the influx of water into the reservoir from an underlying aquifer or water zone to maintain reservoir pressure as oil is produced. This process is particularly pronounced in reservoirs with significant vertical communication between the oil-bearing layers and the aquifer. The degree of water influx is determined by several factors, such as the size and pressure of the aquifer, the permeability of the reservoir, and the production rate.

- **Aquifer Pressure Support**: Aquifer pressure support, often referred to as "strong water drive," helps maintain reservoir pressure as oil is extracted. However, it also increases the likelihood of water production as the reservoir pressure declines. In the case of Niger Delta reservoirs, which often have large underlying aquifers, water influx during production can lead to the phenomenon of high water cuts in producing wells, particularly once natural drive mechanisms (such as gas or solution gas drive) diminish.
- **Water Breakthrough**: In the Niger Delta, water breakthrough is typically observed when the injected water or the natural water influx from the aquifer reaches the wellbore. Strong water drives exacerbate this process because of the high pressure and the increased rate at which water enters the reservoir. This results in increased water production that ultimately leads to a high water-to-oil ratio (WOR).

According to **Zhang et al. (2012)**, in aquifer-supported reservoirs, water cut increases significantly as production continues and water breakthrough occurs earlier than expected, especially if the water drive is strong. This leads to a phenomenon where the water production overtakes oil production, creating operational challenges and higher water disposal costs (Zhang et al., 2012).

2.6 Case Studies and Observations in Niger Delta

Several case studies from Niger Delta oil fields illustrate how strong water drive has contributed to high water cuts in mature reservoirs:

- **Adewumi et al. (2016)** examined the impact of water influx on production performance in the Niger Delta's *Oshika* field, which is characterized by a strong water drive from an active aquifer. Their study showed that the water-to-oil ratio (WOR) increased sharply after a few years of production, with the onset of water breakthrough occurring much earlier than anticipated due to the strong pressure support from the underlying aquifer. This led to a rapid rise in water cut, complicating the production strategy and increasing operational costs.
- **Emebo et al. (2018)** studied water flooding in a mature Niger Delta field that had a strong aquifer support. They found that as water injection intensified to maintain pressure, a higher volume of water was produced from the wells, leading to a higher water cut. The study concluded that despite the enhanced oil recovery from water injection, the increasing water production was a significant challenge, reducing the net oil output and raising the cost of production due to the need for extensive water handling systems (Emebo et al., 2018).
- **Baba et al. (2019)** examined the effects of water influx on water cut in the *Abo* field, a typical Niger Delta reservoir with strong water drive. They noted that the water cut escalated from about 10% to 60% in the first 10 years of production, largely due to the combined effect of natural water influx and water flooding for pressure maintenance. The study identified that strong aquifer support in the field contributed to water coning, which accelerated the rise in water cut, leading to operational and economic challenges (Baba et al., 2019).

These studies demonstrate that strong water drive can significantly influence the onset of high water cuts, especially in reservoirs with large aquifer support or where water injection is used to maintain reservoir pressure.

  - In reservoirs supported by a large and active aquifer, pressure maintenance is effective but water influx may displace hydrocarbons rapidly toward the production wells.

- As the reservoir matures, water encroachment increases, leading to early water breakthrough and a progressive rise in water cut.
- *Key Feature*: Water moves in a piston-like displacement if heterogeneity is low, but fingering and early breakthrough occur in heterogeneous reservoirs.

2. Bottom-Water Coning

Bottom water coning refers to the phenomenon where water from an underlying aquifer or water zone rises into the oil reservoir as oil is produced, causing water to enter the wellbore alongside the oil. This typically occurs in reservoirs with a strong water drive mechanism and can result in a significant increase in water production, which subsequently reduces oil recovery efficiency. In the Niger Delta, where many fields are characterized by a strong water drive and complex geological structures, bottom water coning is a major concern for reservoir management.

Coning is more common in vertical wells, where the production of oil causes the interface between the oil and water zones to move upwards, creating a cone-shaped region of water that encroaches into the oil-producing zone. This issue is especially pronounced in reservoirs with high permeability and insufficient pressure maintenance, where the aquifer provides significant support to the reservoir pressure.

2.7 Factors Contributing to Bottom Water Coning in Niger Delta Reservoirs

- **Aquifer Characteristics**: Strong aquifer support, particularly in reservoirs with extensive water zones beneath the oil column, can lead to rapid upward migration of the water. This is exacerbated in the Niger Delta's reservoirs, where underlying aquifers are often large, and vertical permeability is high. The aquifer pressure typically drives water upwards into the oil zone as production rates increase, leading to early water breakthrough.
- **High Permeability**: Niger Delta reservoirs often have high permeability, which allows water to move easily through the formation. High permeability makes the oil-water interface less stable, increasing the chances of water coning, especially when production rates are high.

- **Production Rate**: When production rates exceed a certain threshold, the downward movement of oil creates a vacuum effect that pulls water into the oil-producing zone from the bottom. In the Niger Delta, production strategies that prioritize high initial oil rates can increase the likelihood of bottom water coning, especially in older, mature reservoirs.
- **Wellbore Geometry**: Vertical wells are particularly susceptible to bottom water coning because of the natural pressure gradient between the oil and water zones. Horizontal or multi-lateral wells can sometimes mitigate the effects of water coning by providing more uniform production profiles and reducing the tendency for water to break through at the bottom.

2.7.1 Consequences of Bottom Water Coning in Niger Delta Reservoirs

Bottom water coning leads to several operational challenges in Niger Delta reservoirs:

- **Increased Water Cut**: As water rises into the wellbore, the water-to-oil ratio (WOR) increases, which ultimately raises the water cut. This is detrimental to oil production as it increases the need for water handling and reduces the efficiency of oil recovery. According to Hassan et al. (2017), bottom water coning is a significant contributor to the rapid increase in water cut observed in many Niger Delta reservoirs, especially as production progresses beyond the primary recovery phase.
- **Reduced Oil Recovery**: The presence of water in the production stream reduces the overall oil recovery rate. Bottom water coning essentially displaces oil, and when water production becomes dominant, oil recovery efficiency drops sharply. **Adeyemo et al. (2016)** highlighted that in fields where bottom water coning is not effectively managed, recovery factors can fall well below potential estimates due to the bypassed oil and increased operational costs (Adeyemo et al., 2016).
- **Increased Operational Costs**: Handling and disposing of produced water can incur significant costs. As water production increases due to bottom water coning, these costs become a major economic burden. The infrastructure required to separate, treat, and dispose of the water may require extensive investment, particularly in offshore or remote areas of the Niger Delta. According to **Olaniyi et al. (2015)**, water handling costs can rise sharply when water cut exceeds 50%, which is common in reservoirs affected by bottom water coning.

- **Equipment Wear and Corrosion**: The increased water cut associated with bottom water coning leads to higher wear and tear on production equipment, such as pumps, separators, and pipelines. **Baba et al. (2019)** found that in Niger Delta oil fields with high water cuts, accelerated corrosion and scaling were significant issues due to the corrosive nature of produced water and emulsions (Baba et al., 2019).

2.7.2 Mitigation Strategies for Bottom Water Coning

Several strategies have been employed to mitigate the effects of bottom water coning in Niger Delta reservoirs:

- **Water Shut-Off Techniques**: One common method is the use of water shut-off treatments, which involve injecting water-blocking chemicals into the reservoir to reduce water production from certain zones. These treatments aim to isolate water-producing zones and prevent the downward movement of water into the oil-producing sections. Ayodele et al. (2019) highlighted the use of these techniques in the Niger Delta to selectively block water-producing zones and improve oil recovery (Ayodele et al., 2019).
- **Horizontal Drilling**: Horizontal wells or multi-lateral wells are increasingly being used to mitigate the effects of bottom water coning. These wells are designed to intersect multiple layers of the reservoir, providing a larger contact area with the oil-bearing zones and allowing for more uniform production across the reservoir. Emebo et al. (2018) noted that in fields with strong bottom water coning tendencies, horizontal drilling has helped reduce the extent of water production and improved overall recovery.
- **Pressure Maintenance via Gas or Water Injection**: To counter the effects of bottom water coning, operators often employ pressure maintenance techniques, such as gas or water injection, to maintain reservoir pressure and control the movement of the oil-water interface. Eke et al. (2017) examined the role of water injection in the Niger Delta and noted that careful management of injection rates could help delay the onset of water coning and maintain oil production rates (Eke et al., 2017).
- **Wellbore Management**: Another approach to mitigating water coning is the use of selective production techniques, where wells are produced at lower rates to reduce the likelihood of bottom water coning. By controlling the flow rate, operators can manage the

movement of the water-oil interface and delay the onset of high water production. Okafor et al. (2018) suggested that production rate optimization based on reservoir monitoring is essential to reduce the impact of water coning and optimize recovery in Niger Delta reservoirs (Okafor et al., 2018).

3. Edge Water Drive

Edge water drive refers to a reservoir drive mechanism in which water moves from the edges of the reservoir (often from a surrounding aquifer or water-bearing formation) into the oil-bearing zones as production occurs. This water influx is typically characterized by water being introduced from the sides of the reservoir, as opposed to the bottom water drive mechanism, where water comes from beneath the oil column. Edge water drive is often observed in reservoirs with a significant lateral communication with a surrounding aquifer or water zone, and it can lead to various operational challenges as production progresses.

In the Niger Delta, where many reservoirs are highly compartmentalized with complex faulting and layering, edge water drive is commonly encountered, especially in mature fields. It is often associated with high permeability and extensive aquifer systems that facilitate lateral water movement. Like bottom water drive, edge water drive can contribute to increased water production, lower oil recovery efficiency, and higher operational costs, especially as the reservoir matures.

2.7.3 Mechanism of Edge Water Drive

Edge water drive is typically seen in reservoirs where there is a lateral connection between the oil-bearing zone and an adjacent aquifer or water zone. As oil is produced from the reservoir, water from the edges of the reservoir is pushed towards the production wells, causing the water-oil interface to move inward.

Key factors influencing edge water drive include:

- **Permeability Contrast**: In many Niger Delta reservoirs, high lateral permeability allows water to move easily from the edges of the reservoir into the oil zone. This is particularly true in the deltaic systems, where fine-grained layers alternate with coarse-grained sands, creating favorable conditions for water to flow from the aquifer into the oil zone.

- **Pressure Depletion**: As the reservoir pressure declines due to production, the lateral movement of water towards the production wells becomes more pronounced. The gradient between the oil and water zones increases, causing more water to be pushed into the oil-producing area.
- **Water Injection and Aquifer Connectivity**: In some cases, water flooding (injection) can exacerbate the effects of edge water drive by artificially increasing the pressure in the aquifer. This can lead to a more rapid influx of water from the edges, accelerating water breakthrough.

In Niger Delta reservoirs, **edge water drive** can lead to early water breakthrough, especially in wells located near the edges of the reservoir. Water encroachment from the edges reduces the volume of oil that can be produced and complicates the management of the reservoir.

2.7.4 Influence of Edge Water Drive on Water Cut in Niger Delta Reservoirs

Edge water drive plays a significant role in the development of high water cut in Niger Delta reservoirs, particularly in mature fields where the pressure has been significantly reduced. The increased water influx from the edges of the reservoir can cause water to break through earlier than expected and increase the overall water-to-oil ratio (WOR), which raises the water cut.

- **Early Water Breakthrough**: In reservoirs experiencing edge water drive, the water-oil interface moves horizontally, and water is more likely to break through at the edge of the reservoir. This leads to early and sustained high water cuts in the wells nearest to the reservoir's edges. Eke et al. (2017) found that edge water breakthrough often occurs earlier in wells located close to aquifer boundaries in the Niger Delta, contributing to rapid increases in water cut (Eke et al., 2017).
- **Water Sweep Efficiency**: Baba et al. (2019) observed that edge water drive can reduce sweep efficiency during water flooding operations because the injected water moves preferentially toward the edges of the reservoir, displacing oil more quickly from the periphery than from the center. This leads to higher water production, especially from wells

located near the edges of the reservoir, where water is entering at higher rates (Baba et al., 2019).

- **Increased Operational Costs**: As water cut increases due to edge water influx, the cost of handling, separating, and disposing of the water increases. This significantly impacts the economics of production. According to Olaniyi et al. (2015), the economic implications of high water cut due to edge water drive are especially significant in mature Niger Delta reservoirs, where production rates are declining and the focus is on minimizing operational costs (Olaniyi et al., 2015).

2.7.5 Case Studies and Observations from Niger Delta Reservoirs

Several studies and field observations in the Niger Delta have highlighted the impact of edge water drive on water cut and overall reservoir performance:

- **The Abo Field**: **Emebo et al. (2018)** studied the impact of edge water drive in the Abo field, a mature Niger Delta reservoir, and noted that edge water influx from an adjacent aquifer significantly contributed to early water breakthrough. This resulted in a rapid increase in water cut, especially in wells located near the edge of the reservoir. The study found that water flooding accelerated water influx from the edges, and well placement optimization became essential to mitigate the impact of high water production (Emebo et al., 2018).
- **The Bonga Field**: The Bonga field, located offshore in the Niger Delta, has also shown the influence of edge water drive. In a study by **Okafor et al. (2019)**, it was revealed that the lateral movement of water from the edges of the field caused early water breakthrough, especially in the northern part of the field, which was in close proximity to a large aquifer. As a result, water production increased, leading to a rise in water cut and operational challenges. The study highlighted the importance of reservoir simulation and pressure monitoring in managing edge water drive (Okafor et al., 2019).
- **The Oshika Field**: In the Oshika field, a strong edge water drive was observed, particularly in the northern part of the field. **Adewumi et al. (2016)** discussed how lateral water influx from an adjacent aquifer led to a sharp increase in water cut, causing water production to rise significantly. The study suggested that optimizing the production rate and adjusting water

injection strategies could help mitigate the effects of edge water influx (Adewumi et al., 2016).

2.7.6 Mitigation Strategies for Edge Water Drive

To mitigate the effects of edge water drive, several strategies can be employed in Niger Delta reservoirs:

- **Well Placement and Drilling Optimization**: Wells should be placed strategically away from the edges of the reservoir to avoid early water breakthrough. **Ayodele et al. (2019)** emphasized that careful well placement, particularly horizontal or multi-lateral wells, can help avoid the influx of water from the edges and extend the life of the oil-producing zones (Ayodele et al., 2019).
- **Water Injection Control**: The rate and location of water injection should be carefully controlled to prevent excessive water influx from the edges. Zhang et al. (2012) suggested that optimized water injection techniques, based on detailed reservoir modeling and simulation, can help prevent rapid water influx and ensure more uniform water sweep across the reservoir (Zhang et al., 2012).
- **Pressure Maintenance and Surveillance**: Continuous monitoring of reservoir pressure and production profiles is essential to manage edge water drive. Eke et al. (2017) recommended using real-time data from downhole sensors and surface monitoring systems to track water movement and make adjustments to production strategies accordingly (Eke et al., 2017).
- **Use of Selective Water Shut-Off (WSO) Techniques**: In cases where water production is concentrated along the edges of the reservoir, water shut-off techniques (such as the use of water-blocking chemicals) can be used to isolate water-producing zones and reduce the impact of edge water influx on overall production (Ayodele et al., 2019).

Edge water drive is a significant driver of water cut in Niger Delta reservoirs, particularly in mature fields with strong aquifer support and high lateral permeability. The lateral influx of water from the edges of the reservoir can cause early water breakthrough, resulting in high water cut and reduced oil recovery efficiency. To mitigate these effects, operators need to employ a combination of reservoir modeling, optimized well placement, water injection control, and advanced monitoring techniques. Understanding and managing edge water drive is crucial for maximizing oil recovery and extending the life of mature oil fields in the Niger Delta.

2.8 Flow Mechanisms at the Wellbore and Near-Wellbore Region

Understanding the flow behavior at the near-wellbore zone is crucial for diagnosing high water cut issues and developing mitigation strategies. The following physical phenomena dominate:

2.8.1 Relative Permeability Effects

Relative permeability is a fundamental concept in reservoir engineering that refers to the ability of a fluid to flow through a porous medium when multiple fluids (e.g., oil, water, and gas) are present in the reservoir. It is defined as the ratio of the permeability of a given phase (e.g., water or oil) to the absolute permeability of the rock. As water production increases, the relative permeability of both oil and water changes, which significantly affects reservoir behavior and the efficiency of oil recovery.

In the context of high water production (or high water cut) in Niger Delta reservoirs, the relative permeability of water plays a key role in influencing the movement of water through the reservoir and the displacement of oil. As reservoirs age, water production tends to rise due to a variety of factors, such as water flooding, pressure depletion, or water influx from natural aquifers. High water cut often results in operational challenges, and the relative permeability effects are central to understanding and managing these challenges.

This section discusses the influence of relative permeability on high water production in Niger Delta reservoirs, with a focus on how changes in relative permeability impact water breakthrough, flow behavior, and recovery efficiency.

2.8.2 The Role of Relative Permeability in Multi-Phase Flow

When two or more fluids are present in the reservoir, the flow of each fluid is influenced not only by the rock's **absolute permeability** but also by the **relative permeability** to each phase. Relative permeability is typically measured experimentally using core samples and can vary significantly with the fluid saturation and the presence of different phases in the reservoir.

- **Water Permeability**: As water saturates a reservoir, the relative permeability of water increases, facilitating its movement toward the production wells. In mature reservoirs with high water saturation, this leads to early water breakthrough and high water production.
- **Oil Permeability**: Conversely, the relative permeability of oil decreases as water saturation increases. This means that water tends to displace oil more easily as the water saturation increases, reducing the efficiency of oil recovery, especially in the presence of strong water drive or water flooding.

The interplay between water and oil relative permeability governs the movement of fluids in the reservoir, influencing the **water cut** and the overall production efficiency.

2.8.3 Influence of Relative Permeability on High Water Production in Niger Delta Reservoirs

In the **Niger Delta**, many of the oil reservoirs are characterized by high permeability and strong water drives, which can exacerbate the effects of relative permeability. As the oil reservoir matures and water production rises, the relative permeability of both water and oil plays a key role in determining how much water is produced in relation to oil, which directly affects the water-to-oil ratio (WOR) or water cut. The following points discuss the primary ways in which relative permeability influences high water production in these reservoirs:

2.8.4 Water Breakthrough and Early Water Production

- **Water Breakthrough**: As oil production continues, the oil-water interface typically moves towards the wellbore. **Relative permeability** governs how easily water can flow towards the wellbore, and when the relative permeability of water is high, water breakthrough happens earlier. This is particularly true in reservoirs with high initial water saturation or strong aquifer support.

In the **Niger Delta**, where many fields have significant water drive and strong lateral connectivity between the aquifer and the oil-bearing layers, water tends to break through early in the production cycle, particularly in the wells located near the edges of the reservoir or near water injection zones.

According to Zhang et al. (2012), high water permeability in Niger Delta reservoirs often leads to the rapid migration of water towards production wells, resulting in early water breakthrough. This increases the water cut in the production stream, thereby reducing oil production efficiency and raising operational costs (Zhang et al., 2012).

2.8.5 Effects of Saturation on Relative Permeability

Water Saturation: As production progresses and the oil is depleted, the water saturation in the reservoir increases. The relative permeability of water increases with water saturation, meaning that water becomes the dominant fluid phase. When the water saturation is high, it becomes easier for water to move through the reservoir, increasing water production rates.

Ayodele et al. (2019) note that in Niger Delta fields, the rapid increase in water saturation leads to an increased relative permeability of water, which in turn leads to higher water cut as oil production decreases. This phenomenon is particularly pronounced in the mature reservoirs where water breakthrough has already occurred, and water saturation is continuously increasing due to natural or artificial water influx (Ayodele et al., 2019).

2.8.6 Reduced Oil Permeability and Efficiency of Oil Recovery

Oil Saturation and Relative Permeability of Oil: As the water saturation increases in the reservoir, the relative permeability of oil decreases, which reduces the oil's ability to flow toward the production well. This means that oil recovery becomes less efficient, particularly when water is occupying a large portion of the pore space. In mature Niger Delta reservoirs, where water production is already high, the decreasing relative permeability of oil compounds the challenges associated with maintaining oil production.

Emebo et al. (2018) studied a mature Niger Delta reservoir and found that the increasing water saturation due to water breakthrough significantly reduced the relative permeability of oil, leading to lower oil recovery efficiency and an increase in the water-to-oil ratio (Emebo et al., 2018). This reduction in oil mobility exacerbates the high water production problem, as more water is produced per unit of oil.

2.8.7 Impact of Water Flooding and Water Injection

In many Niger Delta reservoirs, water flooding is employed as a secondary recovery method to maintain reservoir pressure and increase oil recovery. However, the injection of water into the reservoir can lead to water channeling and an increase in the relative permeability of water. This results in a higher likelihood of early water breakthrough and increased water production.

According to Baba et al. (2019), in Niger Delta reservoirs that employ water flooding, the injected water tends to migrate preferentially through high-permeability channels, bypassing oil-rich areas. The resulting increase in water production leads to an early increase in water cut, which reduces the net oil recovery and increases operational costs associated with water treatment and disposal (Baba et al., 2019).

2.9 Practical Examples and Case Studies

- **Oshika Field (Adewumi et al., 2016)**: The Oshika field, located in the Niger Delta, has been reported to experience significant water production due to strong aquifer support. In this field, relative permeability effects were a critical factor in the early onset of water breakthrough. The study by Adewumi et al. (2016) found that the high permeability of water in the reservoir led to an early increase in water cut, which significantly reduced the efficiency of oil recovery and increased operational costs related to water handling (Adewumi et al., 2016).
- **Abo Field (Emebo et al., 2018)**: The Abo field, another Niger Delta reservoir, experienced a high water cut as a result of strong water drive and the influence of relative

permeability. Emebo et al. (2018) highlighted that the relative permeability of water increased as water saturation rose, which led to water breakthrough and an increase in water cut early in the production phase. This affected the overall oil recovery and posed challenges for reservoir management (Emebo et al., 2018).

2.9.1 Mitigation Strategies for Managing High Water Production

To mitigate the negative effects of high water production due to relative permeability effects in Niger Delta reservoirs, several strategies can be employed:

1. **Water Shut-Off Techniques**: Using selective water shut-off methods, such as water-blocking chemicals or mechanical packers, to prevent water from entering high-permeability zones and reduce water production from specific wells.
2. **Optimizing Water Flooding**: Careful control of water injection rates to ensure that water floods the oil zone uniformly and avoids preferential flow paths that could increase water production.
3. **Enhanced Oil Recovery (EOR)**: Applying techniques such as **polymer flooding** or **CO_2 injection** to improve the sweep efficiency and reduce the relative permeability of water, which could help in reducing water production and improving oil recovery.
4. **Reservoir Simulation and Monitoring**: Using advanced reservoir simulation models and real-time data to monitor changes in water saturation and relative permeability. This helps in optimizing production strategies and managing water production more effectively.

Relative permeability plays a crucial role in the dynamics of high water production in Niger Delta reservoirs. As water saturation increases, the relative permeability of water increases, leading to early water breakthrough and high water cut. This phenomenon is particularly prevalent in reservoirs with strong water drive or water flooding systems. Understanding and managing the effects of relative permeability on water production is key to optimizing oil recovery and minimizing operational costs in these fields. By employing effective water management techniques, such as selective water shut-off, optimized water injection, and enhanced oil recovery methods, operators can mitigate the impact of high water production and extend the productive life of Niger Delta reservoirs.

2.8.9 Capillary Pressure

Capillary pressure is the pressure difference between two immiscible fluids (e.g., oil and water) in a porous medium, caused by surface tension at the interface between the two fluids. It results from the forces exerted by the fluids as they move through the pores of the rock. This pressure difference plays a crucial role in governing the displacement and flow of fluids within a reservoir, particularly in reservoirs undergoing water production.

In the context of **high water production** (i.e., high water cut) in Niger Delta reservoirs, capillary pressure is a critical factor influencing the movement of water and oil within the reservoir. As water is produced alongside oil, the capillary pressure in the reservoir changes, which can influence both the onset of water breakthrough and the rate at which water is produced.

Capillary pressure affects the fluid distribution in the reservoir, the ease with which water and oil move through the reservoir, and the efficiency of oil displacement by water. High capillary pressure, for example, can impede the upward movement of water in the reservoir, while low capillary pressure may facilitate water breakthrough and increase water production rates.

2.9.2 Mechanism of Capillary Pressure

Capillary pressure is a function of several factors, including the **wetting properties** of the rock (whether the rock preferentially wets oil or water), the **pore size distribution**, and the **interfacial tension** between the oil and water phases. It is typically described using the following equation:

$$Pc=\frac{2\gamma\cos\theta}{r}$$

Where:

- Pc= capillary pressure

- γ = surface tension of the fluid (oil-water or water-gas interface)
- θ = contact angle between the fluids and the solid rock surface
- r = radius of the pores (or pore throat)

As capillary pressure increases, water tends to be retained in the smaller pores, while oil remains in larger pores. When oil is produced, capillary pressure can impede the flow of oil, particularly when water production increases. This becomes particularly significant in **mature oil fields**, such as those in the Niger Delta, where water production often rises due to water influx from aquifers or water flooding.

2.9.3 Capillary Pressure and High Water Production in Niger Delta Reservoirs

In Niger Delta reservoirs, which are typically characterized by complex geology and varying permeability, **capillary pressure** plays a significant role in governing fluid distribution and flow, particularly when there is a high water cut. The following key factors highlight how capillary pressure influences water production in these reservoirs:

2.9.3.1 Water Breakthrough and Capillary Pressure

Capillary pressure governs the movement of water and oil in the reservoir and affects the **water breakthrough** phenomenon. **Water breakthrough** occurs when water, often from an underlying aquifer or injected water, first enters the production well. The capillary pressure can influence how quickly water reaches the wellbore, with low capillary pressure allowing water to migrate more easily towards the well.

Low Capillary Pressure: In reservoirs with **low capillary pressure**, water can more easily displace oil, leading to early water breakthrough. This is a common issue in mature reservoirs in the Niger Delta, where water saturation increases due to both natural water influx and water injection for pressure maintenance. In such fields, **water cut** increases rapidly as water moves through the porous media and starts to dominate production.

High Capillary Pressure: Conversely, **high capillary pressure** can delay water breakthrough, as water is unable to flow easily through the rock pores without displacing oil. In Niger Delta reservoirs with strong water drives or enhanced water flooding techniques, capillary pressure may influence the **rate of water production**. In such systems, high capillary pressure may prevent water from entering the production wells until a significant portion of oil is displaced.

According to **Olaniyi et al. (2015)**, capillary pressure influences the rate at which water displaces oil in Niger Delta reservoirs, and a reduction in capillary pressure, often due to pressure depletion or aquifer influx, leads to early and high water cut in mature fields (Olaniyi et al., 2015).

2.9.4 Water Saturation and Capillary Pressure Behavior

Capillary pressure is closely related to the water saturation in the reservoir. As the **water saturation** increases with the production of oil, capillary pressure typically decreases, facilitating the easier migration of water through the reservoir.

Increasing Water Saturation: In mature Niger Delta fields where water production is increasing, the water saturation rises, which leads to a decrease in capillary pressure. This reduced capillary pressure makes it easier for water to flow towards production wells, contributing to a rise in water cut. This is often observed in fields that are heavily water-driven or in those undergoing waterflooding, where the rising water saturation in the formation is a direct result of injected water or natural aquifer support.

Impact on Oil Recovery: As capillary pressure decreases, oil recovery efficiency declines because water displaces oil from the pore spaces, leading to higher water-to-oil ratios (WOR). The relative permeability of oil decreases as water saturation increases, reducing the oil's ability to flow towards the production well and further contributing to high water cut.

2.9.5 Capillary Pressure and Fluid Distribution in Heterogeneous Reservoirs

Niger Delta reservoirs are often **heterogeneous**, with variations in porosity, permeability, and fluid distribution. The heterogeneity of the reservoir affects how capillary pressure influences fluid movement and water production.

Permeability Variation: In reservoirs with a mix of high and low permeability zones, water may preferentially flow through the high-permeability zones, while oil is retained in lower permeability zones. Capillary pressure can affect this distribution by controlling how easily water enters high-permeability zones. If capillary pressure is high in the low-permeability zones, oil is more likely to be trapped, while water is able to migrate more easily through the high-permeability zones, increasing water production in these areas.

Water Flooding and Capillary Pressure: In cases of water flooding, capillary pressure influences the sweep efficiency of the injected water. Low capillary pressure zones are more likely to allow water to flow towards the wellbore, displacing oil, while in areas of high capillary pressure, the oil is more likely to remain in place. This creates heterogeneity in water production, with some wells experiencing higher water cut than others due to the local capillary pressure variations.

According to **Adewumi et al. (2016)**, in the **Oshika field** of the Niger Delta, variations in capillary pressure across the reservoir led to differential water production, where high capillary pressure areas experienced slower water influx, while low capillary pressure zones showed early water breakthrough (Adewumi et al., 2016).

2.9.6 Practical Implications of Capillary Pressure on Water Cut and Oil Recovery

- Early Water Cut: In reservoirs with low capillary pressure, the early onset of water breakthrough is common, especially in fields experiencing water flooding or aquifer influx. This leads to an increase in water cut and a decrease in oil recovery efficiency, as water begins to displace oil earlier in the production cycle.
- Production Optimization: Understanding capillary pressure and its effects on fluid displacement can help optimize production strategies. For example, by managing water

injection rates more effectively and monitoring water saturation, operators can reduce the likelihood of early water breakthrough and manage water cut more effectively.

- Improved Oil Recovery: Techniques such as polymer flooding or CO_2 injection, which aim to reduce the mobility of water or improve the oil displacement efficiency, can help overcome the effects of low capillary pressure and improve overall recovery rates.

2.9.6.1 Mitigation Strategies for Managing Capillary Pressure Effects

To manage the effects of capillary pressure on high water production in Niger Delta reservoirs, several strategies can be employed:

1. Water Injection Optimization: Adjusting the rate of water injection to maintain an appropriate pressure gradient without causing excessive water production can help mitigate the effects of low capillary pressure.
2. Selective Production: By selectively producing from regions with lower water saturation and higher oil saturation, operators can delay water breakthrough and reduce water cut.
3. Enhanced Oil Recovery (EOR): Techniques such as surfactant flooding or polymer flooding can reduce capillary pressure and improve oil recovery by reducing the ability of water to bypass oil in low-permeability zones.
4. Reservoir Monitoring: Continuous monitoring of capillary pressure and water saturation can help operators make real-time adjustments to production and injection strategies.

Capillary pressure is a critical factor in the behavior of fluid flow in Niger Delta reservoirs, particularly as water production increases. High water cut is often a direct result of changes in capillary pressure, especially as water saturation increases. In mature fields, where water influx from aquifers or water flooding can rapidly raise water saturation, capillary pressure decreases, facilitating the movement of water and leading to high water cut. Understanding and managing capillary pressure is crucial for optimizing oil recovery and minimizing operational challenges in these fields.

1. **Fingering and Channeling**

Water production problems in oil and gas reservoirs are a significant challenge in reservoir management, especially in mature fields. These issues arise from the dynamics of water injected into reservoirs for enhanced oil recovery (EOR) or water flooding operations. Among the various mechanisms that can lead to operational difficulties, viscous fingering and channeling are two primary phenomena that adversely affect water injection efficiency and lead to disproportionate water production. This review discusses the impact of viscous fingering and channeling on water production problems, focusing on their mechanisms, causes, and effects based on existing literature.

2.9.7 Viscous Fingering

Viscous fingering refers to the instability that occurs when a more viscous fluid (e.g., oil) is displaced by a less viscous fluid (e.g., water) in a porous medium. This phenomenon typically manifests when the mobility ratio between the displacing fluid (water) and the displaced fluid (oil) is unfavorable, i.e., the water is much less viscous than the oil. The displacement front becomes unstable, leading to the formation of "fingers" or preferential flow paths that bypass large portions of the reservoir, reducing the sweep efficiency of the water flood.

2.9.7.1 Mechanisms of Viscous Fingering

The primary cause of viscous fingering is the difference in fluid viscosities, but it is also influenced by factors such as injection rates, reservoir heterogeneity, and capillary pressure. When water is injected at a rate that exceeds the natural resistance of the reservoir to flow, fingers of water form, flowing preferentially through the path of least resistance. This results in poor contact between the water and the oil, leaving significant portions of the reservoir unswept and resulting in increased water production without corresponding oil recovery.

Impact on Water Production

Viscous fingering leads to early water breakthrough at production wells, where water produced from the reservoir is disproportionate to oil production. This causes inefficient water flooding and accelerates the need for secondary recovery techniques. A study by Liu et al. (2019) discusses how viscous fingering not only lowers oil recovery but also results in increased operational costs due to the need for more sophisticated water handling systems. Similarly, Leas et al. (2017) found that large-scale simulations showed that viscous fingering can decrease oil recovery by up to 30% in certain conditions.

Channeling - Channeling, often considered a consequence of viscous fingering, is the formation of high-permeability flow paths that bypass large portions of the reservoir. In the context of water injection, channeling occurs when water preferentially flows through regions of the reservoir with higher permeability, leading to uneven displacement of oil.

Mechanisms of Channeling

Channeling can be influenced by heterogeneities in reservoir rock properties such as porosity and permeability. When water is injected into a reservoir, it preferentially flows through channels of high permeability, bypassing low-permeability regions. As a result, substantial volumes of oil are left behind in these less permeable areas, while water flows through the high-permeability channels. This phenomenon is exacerbated in reservoirs with complex geological structures, where permeability contrasts are large.

Impact on Water Production

The primary consequence of channeling is the premature breakthrough of water at production wells, which increases water cut and decreases oil production. This reduces the overall efficiency of the water flooding process, as significant portions of oil are left unrecovered. Niemi et al. (2020) demonstrated that channeling leads to early and uneven water breakthrough, increasing the water-to-oil ratio and leading to higher water production without equivalent oil recovery. Zhou et al. (2018) noted that channeling could decrease the efficiency of waterflood operations by up to 40% in highly heterogeneous reservoirs.

2.9.8 Combined Effects of Viscous Fingering and Channeling

Viscous fingering and channeling are not independent phenomena but often occur together. As water injection progresses, fingering can lead to the formation of channels that facilitate the rapid transport of water through parts of the reservoir, exacerbating water production issues. The combination of these two mechanisms can lead to a vicious cycle, where early water breakthrough increases water cut, which in turn accelerates the development of more fingers and channels, further reducing oil recovery and increasing water production.

A study by Zhang et al. (2021) examined the combined impact of viscous fingering and channeling on the performance of water flooding in a heterogeneous reservoir. The results showed that the joint effect of these two phenomena could lead to a 50% reduction in oil recovery efficiency, with water production increasing disproportionately compared to oil.

2.9.8.1 Mitigation Strategies

Several strategies have been proposed to mitigate the negative effects of viscous fingering and channeling. Tightening the mobility ratio by reducing the injection rate or by adding polymer solutions to the injected water is one common approach. According to Alvarado and Manrique (2010), the use of polymers increases the viscosity of the injected water, reducing the mobility contrast and thus diminishing the tendency for viscous fingering. Moreover, microbial enhanced oil recovery (MEOR) has been explored as a potential technique to reduce channeling by altering the permeability of high-permeability zones, thereby promoting more uniform water injection across the reservoir (Zhang et al., 2022).

Another approach involves modified injection techniques, such as alternating water and gas injection (WAG) or surfactant-enhanced waterflooding, which aim to reduce the flow of water through high-permeability channels by increasing the viscosity and capillary forces between water and oil (Khoshghalb et al., 2015). However, the success of these methods depends on the specific conditions of the reservoir, including its geological characteristics and the degree of heterogeneity.

Viscous fingering and channeling are significant causes of water production problems in oil and gas reservoirs, leading to inefficient waterflooding, early water breakthrough, and increased water-to-oil ratios. These phenomena are driven by mobility contrast, reservoir heterogeneity, and fluid viscosity differences, and their combined effects can result in substantial reductions in oil recovery efficiency. While various mitigation strategies, including the use of polymer flooding and modified injection techniques, have been proposed, the effectiveness of these methods varies depending on the reservoir conditions. Future research into reservoir characterization and advanced flooding techniques may provide more effective solutions to these challenges.

Viscous Instabilities

When water viscosity is much lower than oil viscosity, viscous fingering occurs due to unfavorable mobility ratio ($M > 1$). This causes irregular water fronts and early water breakthrough at producing wells.

2.9.9 Production-System Factors Influencing Water Cut

The production system itself can exacerbate or mitigate water production, depending on design and operation:

Injection/Production Schedules

- High injection rates can accelerate water breakthrough by increasing pressure gradients and forcing water through high-permeability zones.
- Uneven production rates can unbalance reservoir sweep, leading to localized coning or cresting.

Well Completions and Perforation Placement

- Perforating close to the oil-water contact (OWC) or in high-permeability layers increases the risk of early water production.
- Selective completions and inflow control devices (ICDs) can balance flow and delay water breakthrough.

Layered Reservoirs and Crossflow

- In multilayer systems, crossflow between high-permeability and low-permeability layers can accelerate water movement.

- Without zonal isolation, water from watered-out zones may enter the wellbore and dominate production, even if oil is still present in other layers.

2.9.9.2 Key Empirical and Analytical Models – Water cut prediction

Several classical models exist to predict and control water production in mature wells:

1. **Coning Theory**
   - Developed by Muskat (1937), this theory describes the critical rate at which water is pulled upward into the wellbore.
   - Modern models extend coning theory to three-dimensional cases and multilayer systems.
2. **Critical Rate Analyses**
   - Analytical expressions (Chaperon, 1986; Abbaszadeh & Cinco-Ley, 1995) provide **critical production rates** below which water or gas coning is minimized.
   - These are vital for production optimization and rate control strategies.
3. **Two-Phase Relative Permeability Models**
   - Corey (1954) and LET models are commonly used to represent oil-water relative permeability behavior.
   - History-matched *kr* curves are essential for predicting water cut performance in reservoir simulation and MBAL studies.

2.9.9.3 Diagnostic and Surveillance Techniques

- Production logging tools (PLT) such as spinner flowmeters, temperature and noise logs, and multi-phase flowmeters are mainstays for locating inflow contributions in vertical and horizontal wells (Morris, 1999). Modern PLT integrates multiphase flow models and can estimate zone-wise oil, water and gas contributions under flowing conditions.
- Tracers (radioactive or chemical) are employed to detect fluid communication across layers and to estimate travel times—important in diagnosing channeling and thief zones. Combined tracer/PLT programs increase confidence in zoning decisions (Diagnosing and Controlling Excessive Water Production, 2024).

- Repeated seismic monitoring can image large-scale water-front movement and aquifer invasion. 4D seismic is expensive but valuable in field-wide conformance planning and identifying patterns not apparent from well data alone (Kingue, 2025).

2.9.9.4 Well-Level Remediation and Completion Strategies

- Mechanical zonal isolation: packers, staged plugs and recompletion to isolate watered intervals.
- Chemical water shut-off: polymer gels, relative permeability modifiers, cement squeeze and selective.
- Sidetracking and re-perforation to bypass damaged or highly watered intervals.
- Inflow control devices.

The literature stresses that diagnostic confidence must be high before applying permanent treatments since many treatments are irreversible or costly. (Diagnosing and Controlling Excessive Water Production, 2024).

2.9.9.5 Field-Wide Options for Water Management

At the field scale, integrated water management strategies are applied to control excessive water production and improve sweep efficiency:

1. **Water Shutoff in Patterns**
    - Shut-in of high-water-cut producers or injectors that are causing water cycling.
    - Improves reservoir pressure support and recovery efficiency.
2. **Infill Drilling**
    - Strategic drilling of additional wells to target bypassed oil zones or improve areal sweep.
3. **Producer/Injector Rebalancing**
    - Adjusting injector rates or patterns to optimize sweep and delay water breakthrough.

4. **Revised Allocation and Choke Management**
    - Controlling production choke sizes to keep production rates below critical coning rates.
5. **Subsea/Flowline Remediation**
    - Removal of hydrates, wax, or scale that may cause backpressure and promote water coning.

2.9.9.6 Artificial Lift: Theory, Design and Operational Constraints

Artificial lift selection is central to mature-field optimization. Key metrics include achievable liquid rates, allowable gas–liquid ratio (GLR), sensitivity to solids and sand, temperature limitations, energy consumption, and life-cycle costs. Several review papers and design guides summarize these trade-offs and optimization approaches (Janadeleh, 2024).

Gas Lift

Gas lift reduces the effective hydrostatic head by injecting gas into the production tubing, creating a two-phase column with lower density. Gas lift can be implemented as continuous gas lift (CGL), intermittent (plunger) lift in some scenarios, or advanced intelligent gas lift (with downhole valves and control). Advantages: flexibility for multi-zone wells, tolerance to some solids, relatively simple surface equipment. Limitations: requires reliable supply of lift gas and compression, efficiency drops at high water cuts and very high GLR conditions, and management complexity increases for large numbers of wells (Gas Lift Design Guide, n.d.; Petex GAP documentation, n.d.).

Electrical Submersible Pumps (ESP)

ESPs are centrifugal pumps driven by an electric motor in the well. They provide high liquid rates and are often selected when high drawdown is required. ESPs are sensitive to free gas presence (risk of gas locking), solids/abrasion, and high temperatures which affect motor life (Janadeleh, 2024; ResearchGate 2023). Modern ESP deployments incorporate gas handlers, gas separators, and variable speed drives (VSD) to mitigate some limitations. ESP reliability and workover frequency are major economic considerations.

2.9.9.7 Comparative performance under high water cut

Comparative studies (academic and industry case reports) generally find that ESPs can deliver higher peak liquid rates and, in many cases, higher NPV when site conditions (power availability, temperature, solids) are favourable (Alaigba 2025). Gas lift may be preferred when gas is plentiful/cheap or where ESP reliability concerns and workover access risks are prohibitive. Several Niger Delta-specific studies simulate both options using PROSPER/PIPESIM and show varying break-even conditions depending on gas availability, well depth, and water cut trajectories (Ubanatu & Igwilo, 2023; Alaigba, 2025).

2.9.9.8 Full-Field and Surface Network Optimization: GAP / IPM

This study adopts an Integrated Production Modelling (IPM) approach to optimize production from a mature, high water-cut reservoir. The methodology couples three core numerical tools within the Petroleum Experts IPM suite:

- MBAL – used to perform material balance calculations and construct a tank-based reservoir model for quick estimation of original fluids in place, aquifer strength, and production performance under varying scenarios.
- PROSPER – applied for well performance modelling through inflow performance relationship (IPR) and vertical lift performance (VLP) analysis, enabling accurate prediction of well deliverability under different operating conditions and artificial lift configurations.
- GAP – serves as the network and system optimizer, integrating MBAL reservoir tanks and PROSPER well models into a single surface network model. GAP enables simulation of well interactions, choke settings, facility constraints, and global optimization to maximize oil production while minimizing water handling costs.

This integrated workflow allows history matching, sensitivity analysis, and scenario evaluation at well, reservoir, and field-wide levels — providing a robust decision-support framework for production optimization and asset life extension.

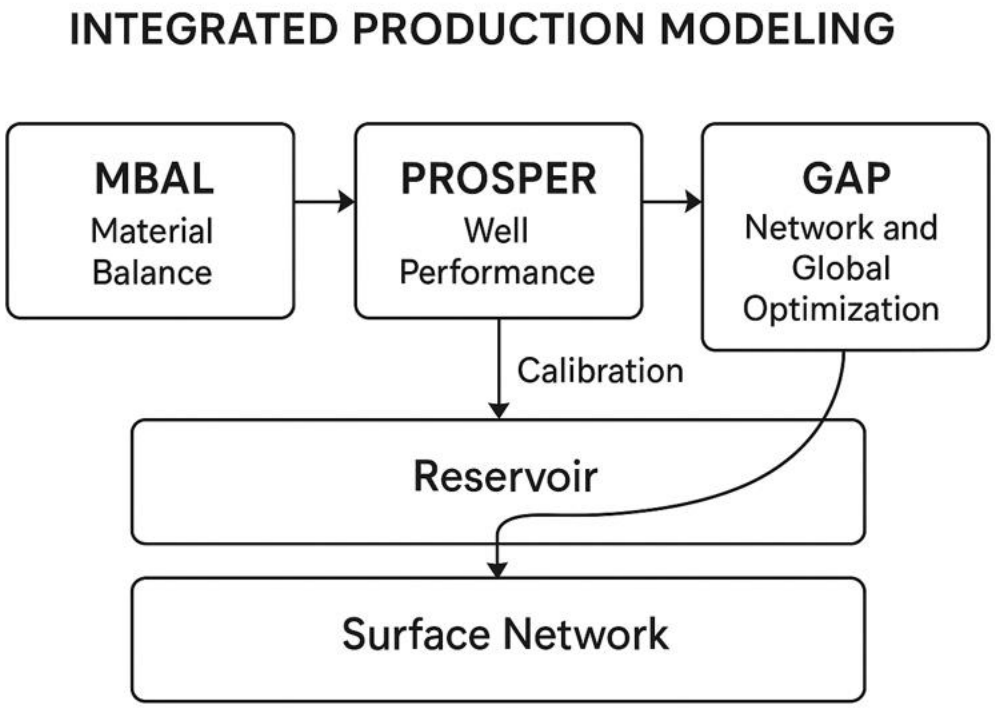


Figure 2.2: integrated production modelling workflow

GAP (PETEX) and IPM tools enable coupling of well performance models with gathering lines, separators, compressors and processing constraints to assess field-wide behavior and optimization (Petex IPM suite docs, n.d.; Petex GAP guide, 2021). The integrated approach captures interactions such as pressure feedback, compressor loading, gas allocation for lift, and limits on processing throughput. GAP supports optimization tasks including gas allocation for gas lift, shutdown decisions, and sensitivity studies across reservoir decline scenarios (Petex IPM Getting Started Guide, 2021).

Full-field optimization studies typically link: reservoir simulator outputs (relative permeability changes, pressure maps) -> well models (PROSPER/nodal) -> surface network (GAP/PIPESIM) -> economic module (NPV/IRR). Iterations or surrogate models may be used to accelerate global optimizations (Petex, n.d.; Utpedia, 2012).

2.9.9.9 Modelling Tools and Coupled Workflows

Key tools cited in the literature include reservoir simulators (ECLIPSE, CMG), nodal and well-performance tools (PROSPER, WellFlo), and surface/network hydraulics (GAP, PIPESIM).

Workflows differ by fidelity: high-fidelity reservoir–well–surface coupling is used for critical decisions while surrogate-assisted models are used for optimization searches where simulation cost is high (Petex, n.d.; OnePetro examples).

Optimization Algorithms and Approaches

Optimization approaches in production systems range from deterministic gradient-based methods to population-based global optimizers (genetic algorithms, particle swarm optimization, CMA-ES). When the simulation model is expensive, surrogate models (kriging, polynomial response surfaces, neural networks) can accelerate the search (Gas lift optimization review, 2022). Multi-objective optimization is common when trade-offs exist between production, water cut, and OPEX/CO2 emissions.

2.10.1 Economic Evaluation and Risk Analysis

Economic comparison of artificial lift options requires life-cycle costing, including CAPEX (equipment, installation, wellwork), OPEX (power, compression, maintenance), and indirect costs (downtime, environmental fees). Standard metrics include NPV (discounted cash flows), IRR, payback, and sensitivity/Monte Carlo analysis to capture uncertainty in oil price, OPEX and failure rates (Janadeleh, 2024; Petex docs).

2.10.2 Niger Delta Case Studies and Regional Evidence

Recent and regionally-focused studies provide empirical comparisons of gas lift and ESP in Niger Delta wells. For example, Ubanatu & Igwilo (2023) applied PROSPER models to compare both systems for a deepwater Niger Delta well and observed ESP superiority in delivered liquid rate under the case's power and gas assumptions (Ubanatu & Igwilo, 2023). Alaigba (2025) and OnePetro abstracts report similar comparative assessments and emphasize site-specific drivers. Machine-learning based artificial lift optimization using Niger Delta datasets has also been explored (Preprints, 2025).

Methodology

To optimize the production of the mature Niger Delta reservoir, which is facing challenges from high water cut and declining oil recovery rates, three primary modeling tools were employed: Prosper Mbal and GAP Modeling. These tools were selected due to their ability to provide detailed insights into both reservoir behavior and surface production system performance. The integrated approach of these models enabled a comprehensive evaluation of reservoir dynamics and facilitated optimization across both subsurface and surface systems.

3.1 Mbal (Material Balance)

Mbal is a widely-used reservoir engineering software that integrates material balance and decline curve analysis to simulate reservoir performance. It helps predict future production and identify potential issues related to water production, gas injection, and other factors that affect long-term reservoir health.

Purpose in the Study: Mbal was employed to evaluate the performance of the Niger Delta reservoir by incorporating historical production data, reservoir fluid properties, and well performance. The material balance component of Mbal allowed for the calculation of reservoir fluid volumes, pressure behavior, and saturation changes, which are essential for understanding how much oil can be recovered over time.

Model Calibration and History Matching: Mbal was calibrated using historical production data to ensure accurate representation of the reservoir's performance. History matching involved adjusting model parameters (such as permeability, skin factor, and reservoir pressure) to align the simulation with actual field production data.

3.2 GAP Modeling (Gas Allocation Program)

GAP Modeling focuses on simulating the flow of fluids (oil, gas, and water) through the surface production system. This model optimizes the distribution of produced fluids, evaluates the performance of surface facilities such as separators, compressors, and pipelines, and suggests the most efficient way to allocate production across different wells and facilities.

Purpose in the Study: The GAP model was used to simulate the entire production network, from the wells through the gathering system and processing facilities. This provided a detailed understanding of how changes in well production rates (including water injection and gas lift) would affect surface facilities and overall system performance.

Optimization of Surface System: By modeling the entire fluid flow system, the GAP model enabled the identification of bottlenecks and inefficiencies in the production process. For example, it helped assess how changing well pressures, adjusting gas injection rates, or optimizing water handling strategies could improve production and reduce the impact of water cut on oil recovery.

Gas and Water Handling: The model also allowed for the optimization of gas lift operations and water handling techniques. By fine-tuning these parameters, the model helped propose solutions to reduce high water cut while maintaining or increasing oil production rates.

3.3 Integrated Approach of Prosper Mbal and GAP Modeling

The integration of Prosper Mbal and GAP modeling provided a holistic approach to reservoir and production system optimization. Prosper Mbal was used to model and predict the subsurface behavior, while GAP modeling focused on surface facility performance and optimization.

Combined Modeling: By combining the results from both Prosper Mbal and GAP, a more comprehensive understanding of the reservoir and production system was achieved. This integration allowed for the identification of optimal production strategies that consider both the reservoir dynamics (such as gas cap behavior and pressure depletion) and the surface infrastructure (such as the ability of the separation and compression systems to handle increased production volumes or fluctuating water cuts).

Feedback Loop for Optimization: The results from Prosper Mbal provided key insights into the reservoir’s fluid behavior, which were then used to optimize the surface system in GAP modeling. Conversely, the findings from GAP modeling helped refine the Prosper Mbal model, ensuring that surface facilities were adequately represented in the overall production optimization strategy.

3.4 Geographical Location of the Niger Delta

The Niger Delta is located in the southern part of Nigeria, along the Gulf of Guinea. It is one of the largest and most prolific oil and gas-producing regions in the world. The delta is characterized by a complex system of rivers, creeks, and offshore areas, covering an approximate area of 70,000 square kilometers. The delta's oil and gas fields are concentrated along the Niger River, which drains into the Atlantic Ocean.

The region's reservoirs are typically situated in both onshore and offshore environments, with a mix of shallow and deepwater deposits. The offshore fields are located in the continental shelf and deeper deepwater areas of the Gulf of Guinea. These fields are often more challenging due to their remote locations and complex subsurface geology.

3.4.1 Key Characteristics of the Reservoir

The Niger Delta reservoirs are some of the most challenging yet productive oil fields in the world. Below are the key characteristics typically found in the reservoirs in this region:

Depth: The oil-bearing reservoirs in the Niger Delta are generally found at depths ranging from 1,000 meters to over 4,000 meters below the surface. Offshore reservoirs tend to be at greater depths compared to onshore fields. The pressures and temperatures at these depths influence reservoir performance and recovery methods.

Fluid Properties:

Oil: The reservoirs in the Niger Delta typically produce light crude oil, with API gravity values ranging from 20 to 40 degrees. This indicates that the crude oil is of good quality and has relatively low viscosity, which aids in production. However, the oil may exhibit varying characteristics depending on the specific reservoir.

Gas: The gas produced in the Niger Delta is typically associated gas, found in close proximity to the oil. The gas-to-oil ratio varies depending on the field, and there may be significant amounts of associated gas in some fields.

Water: The production of formation water is common in the Niger Delta fields, especially in mature reservoirs. The water often contains high salinity, which can complicate water management strategies.

Age: Many of the Niger Delta reservoirs are classified as mature, having been in production for several decades. The maturity of the reservoir affects its ability to sustain high production rates, with many fields experiencing natural pressure depletion over time, leading to reduced oil output. As a result, enhanced oil recovery (EOR) techniques such as gas injection, water flooding, and artificial lift are often employed to maintain production.

3.4.2 Geological Formation:

Depositional Environment: The Niger Delta is primarily characterized by deltaic and shallow marine deposits, with complex stratigraphy. Reservoirs are typically found in sandstone formations, which are interbedded with shale layers. The delta's sedimentary environment is responsible for the complexity of the reservoirs, which often exhibit significant heterogeneity in terms of porosity and permeability.

Structural Features: The region's reservoirs often contain complex geological features, such as faults, fractures, and salt domes. These features can significantly affect reservoir flow patterns, complicating both reservoir management and production forecasting.

Reservoir Drive Mechanisms: Niger Delta reservoirs generally rely on a combination of solution gas drive, water drive, and gas cap expansion to support production. As the reservoir matures, gas production may also become significant, requiring careful management of gas injection and handling.

Water Cut Problem: High Water Cut and Its Impact on Production

Water cut refers to the percentage of water in the total produced fluid (oil + water). It is an important parameter that reflects the efficiency of oil production. High water cut occurs when the volume of water produced along with oil increases significantly, leading to several challenges in reservoir management and production optimization.

In the context of the Niger Delta, many of the mature reservoirs experience an increase in water cut as they age. This is due to a variety of factors, including:

Reservoir Depletion: Over time, natural reservoir pressure declines, and water from the aquifer or surrounding formations begins to encroach into the production wells, leading to increased water production.

Water Flooding and Injection Issues: In some cases, water flooding (used as an enhanced oil recovery method) may result in a higher water cut if the injected water is not properly managed or if there are issues with the water injection system, such as improper distribution or breakthrough of injected water into the production wells.

Geological Factors: The heterogeneous nature of the Niger Delta's reservoirs—such as variations in porosity, permeability, and the presence of faults—can cause uneven flow paths, leading to preferential water channels and increased water production in certain wells.

3.4.3 Impact of High Water Cut on Production:

Reduced Oil Recovery: As water cut increases, the proportion of oil produced decreases, leading to a decline in overall oil recovery and a rise in operating costs due to the need to handle large volumes of produced water.

Increased Operating Costs: High water cut requires additional handling of water produced along with oil, which results in higher costs for water separation, treatment, and disposal. The water handling facilities must be sized appropriately, which can increase capital and operational costs.

Wellbore Damage and Reservoir Performance: High water cut can affect wellbore integrity and lead to issues such as scaling, corrosion, and formation damage. These challenges may further reduce well productivity and complicate the production process.

Reduced Well Efficiency: As the water cut increases, the oil flow rate tends to decline because the water displaces the oil in the reservoir. Additionally, the water can cause emulsion formation, which can further complicate oil extraction processes.

3.5 Data acquisition

PVT

The fluid PVT data is displayed in the figure below.

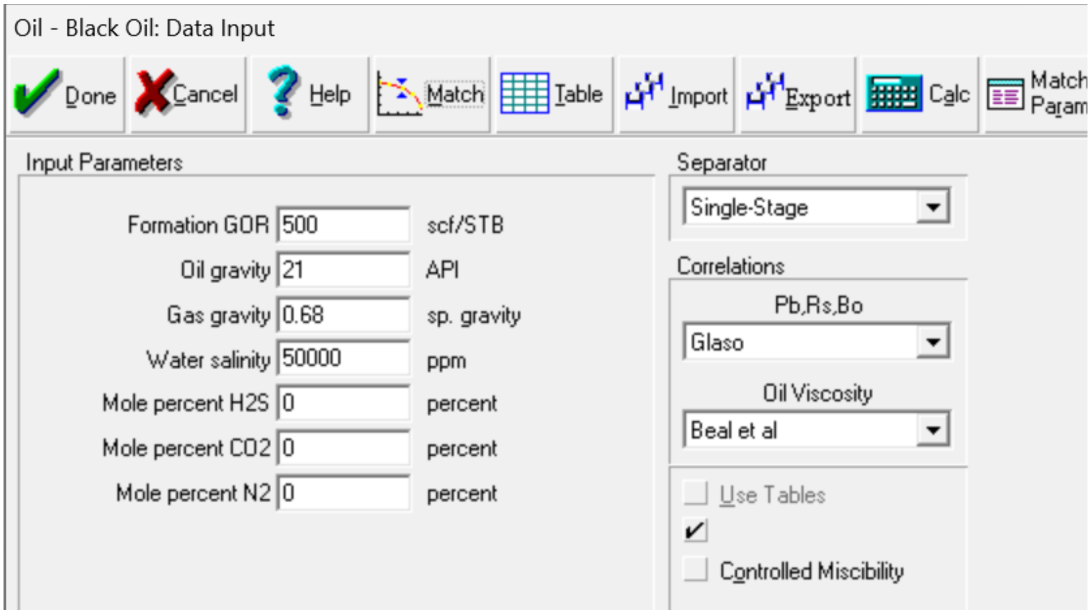


Figure 3.1: Fluid PVT input section

As part of the reservoir simulation workflow for production optimization, black oil PVT properties were defined using a correlation-based approach within the reservoir simulator. Figure 3.1 illustrates the Black Oil Data Input interface, which was employed to generate pressure-dependent oil properties required for dynamic simulation of the mature, high water cut Niger Delta reservoir.

The reservoir fluid was modeled as a black oil system, which is appropriate for mature oil fields where compositional variations are limited and long-term production performance is dominated by oil–water interactions rather than detailed phase behavior. The input parameters used to characterize the reservoir oil and associated gas include:

Formation Gas–Oil Ratio (GOR): 500 scf/STB

Oil Gravity: 21° API, indicating a moderately heavy crude typical of Niger Delta reservoirs

Gas Gravity: 0.68 (air = 1)

Formation Water Salinity: 50,000 ppm

Acid Gas Content: H_2S = 0%, CO_2 = 0%

Inert Gas Content: $N_2 = 0\%$

These values were selected based on available field data and regional analogs, ensuring consistency with the known fluid characteristics of mature Niger Delta reservoirs.

A single-stage separator model was adopted to represent surface separation conditions, which is commonly used for field-scale simulation studies where detailed surface facility modeling is not the primary objective.

The following empirical correlations were applied:

Bubble Point Pressure (Pb), Solution Gas–Oil Ratio (Rs), and Oil Formation Volume Factor (Bo): Glaso correlation

Oil Viscosity: Beal et al. correlation

The Glaso correlation was selected due to its proven reliability for medium to heavy oils and its widespread application in sandstone reservoirs. The Beal viscosity correlation was used to accurately capture oil mobility trends, which are critical in high water cut systems where small changes in oil viscosity significantly affect fractional flow and water production behavior.

The generated PVT properties were subsequently used by the simulator to compute pressure- and saturation-dependent oil properties during production forecasting and optimization runs. This ensured a consistent and physically representative description of fluid behavior throughout the simulation period.

Overall, the use of a correlation-based black oil PVT model provided a robust and computationally efficient framework for evaluating production optimization strategies such as well rate control, water management, and infill drilling in the mature Niger Delta reservoir.

3.5.5 PVT Matching

Following the definition of black oil input parameters, a PVT matching and validation step was carried out to ensure consistency between the generated fluid properties and expected reservoir behavior. Figure 3.2 presents the Black Oil Matching interface, which was used to verify and fine-tune pressure-dependent oil and gas properties applied in the reservoir simulation model.

The PVT matching was performed at a reservoir temperature of 160°F, representative of the target Niger Delta reservoir. The bubble point pressure was defined as 2725 psig, indicating the pressure at which free gas begins to evolve from the oil phase under reservoir conditions. This value is consistent with the selected formation GOR and oil gravity and is critical for accurately capturing solution gas drive effects during pressure depletion.

The matching table displays key black oil properties as functions of pressure, including:

Pressure (psig)

Solution Gas–Oil Ratio (Rs) in scf/STB

Oil Formation Volume Factor (Bo) in RB/STB

Oil Viscosity (μo) in centipoise

Gas Formation Volume Factor (Bg) in ft^3/scf

Gas Viscosity (μg) in centipoise

At the bubble point pressure of 2725 psig, the solution GOR is 500 scf/STB, the oil formation volume factor is 1.404 RB/STB, and the oil viscosity is 8.9 cP, reflecting relatively expanded and mobile oil at saturated conditions. As pressure decreases below the bubble point, a progressive reduction in Rs and Bo is observed, accompanied by an increase in oil viscosity. For example, at 1934 psig, Rs declines to 471 scf/STB, Bo reduces to 1.316 RB/STB, and oil viscosity increases to 12 cP, while further depletion to 1425 psig results in an oil viscosity of 14.5 cP.

This pressure-dependent trend is physically consistent with gas liberation from solution and increasing oil resistance to flow as reservoir pressure declines. Capturing this behavior is particularly important in mature, high water cut reservoirs, where reduced oil mobility exacerbates water dominance and accelerates production decline.

The matched PVT tables generated from this process were subsequently integrated into the dynamic reservoir simulation model. This ensured that oil and gas flow behavior, well productivity, and water breakthrough predictions during optimization scenarios were governed by realistic fluid property variations over the depletion history.

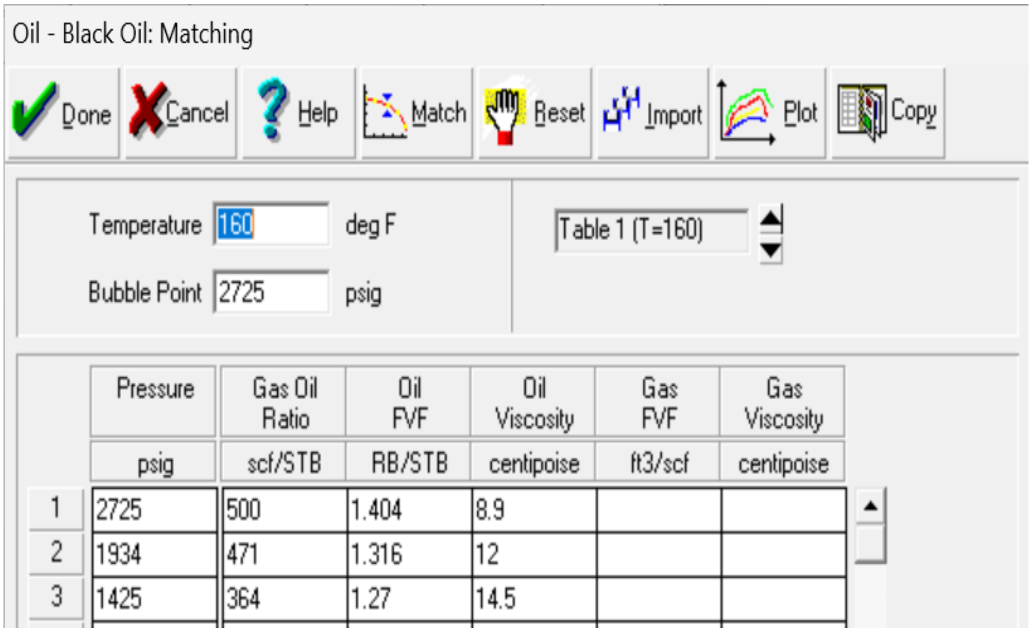


Figure 3.2: Black oil Matching section

3.5.6 History matching

Analytical Material Balance and Aquifer Modeling

An analytical material balance method was applied to evaluate reservoir pressure behavior and quantify the influence of aquifer support in the mature Niger Delta reservoir. Figure 3.3 presents the relationship between tank pressure and cumulative oil production, comparing scenarios with and without aquifer influx.

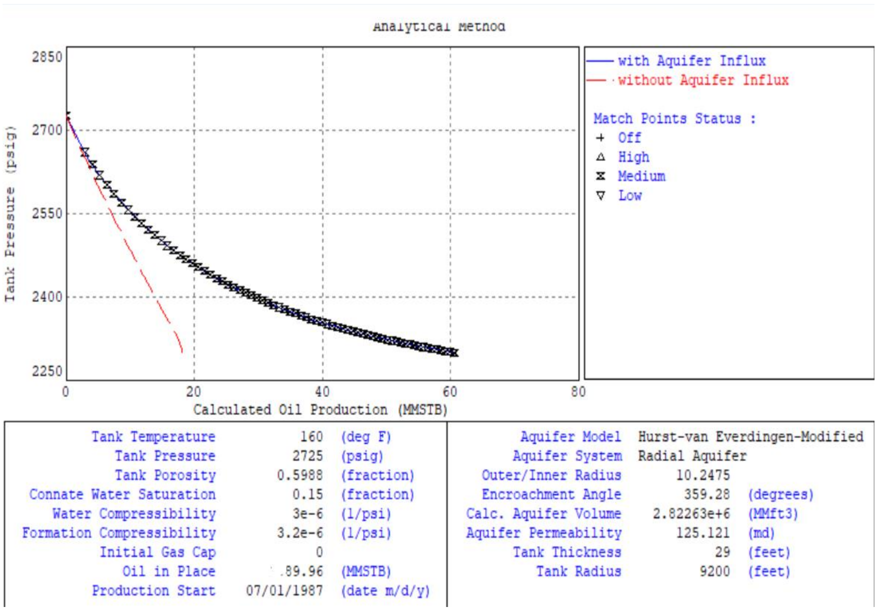


Figure 3.3: Analytical method of history matching

The analysis was conducted at a reservoir temperature of 160°F, with an initial reservoir pressure of 2725 psig, corresponding to the previously matched bubble point pressure. The analytical approach allowed for rapid screening of reservoir drive mechanisms prior to full-field numerical simulation, which is particularly useful in high water cut reservoirs where water influx significantly affects pressure maintenance and production performance.

Two cases were evaluated:

With aquifer influx (blue curve), representing a pressure-supported system

Without aquifer influx (red dashed curve), representing a depletion-driven system

The results show that inclusion of aquifer support leads to a more gradual pressure decline with increasing cumulative oil production, indicating strong water drive behavior. In contrast, the case without aquifer influx exhibits a steeper pressure decline, highlighting the critical role of aquifer support in sustaining reservoir pressure in the studied field.

Aquifer behavior was modeled using the Hurst–van Everdingen modified analytical aquifer model, assuming a radial aquifer geometry. The selected aquifer and reservoir parameters used in the analysis include:

Reservoir porosity: 0.5988

Connate water saturation: 0.15

Water compressibility: 3×10^{-6} psi^{-1}

Formation compressibility: 3.2×10^{-6} psi^{-1}

Initial gas cap: Absent

Oil initially in place: 89.96 MMSTB

Tank thickness: 29 ft

Tank radius: 9200 ft

Aquifer-specific parameters include:

Outer/Inner radius ratio: 10.2475

Encroachment angle: 359.28°

Calculated aquifer volume: 2.82×10^6 MMft^3

Aquifer permeability: 125.1 mD

Historical production matching was performed by comparing calculated pressure profiles with available field pressure data, categorized into high, medium, and low confidence match points. The close agreement between the calculated pressure trend with aquifer influx and observed pressure data confirms the presence of an active aquifer system contributing to sustained pressure but also explains the persistently high water cut observed during late-stage production.

This analytical material balance and aquifer evaluation formed the basis for subsequent numerical reservoir simulation and production optimization, including water control strategies and well management scenarios.

3.5.7 Regression

In history matching, the software uses a regression or optimization algorithm to automatically adjust uncertain reservoir parameters until the simulation results (e.g., pressure and production rates) closely match the historical field data.

Role in History Matching Methodology

This process is a core component of validating a reservoir model and can be described in a methodology section as follows:

Objective Function Minimization: The software minimizes an "objective function" (or mismatch function) which is a mathematical measure of the difference between the actual observed production/pressure data and the data predicted by the simulation model. The "Standard Deviation" value in the image represents a measure of this mismatch.

Automated Parameter Adjustment: The user selects which parameters the software is allowed to change during the optimization process by checking the boxes under "Regress on". In the image, parameters such as Outer/Inner Radius (aquifer geometry), Encroachment Angle, and Porosity are selected for adjustment. The "Start" column shows the initial guesses, and the "Best Fit" column will display the optimized values found by the algorithm to achieve the best match.

Iterative Process: The software runs through multiple "Iterations" (as indicated by "Iteration No"), recalculating the reservoir's performance with updated parameters in each step until a satisfactory match is achieved, indicated by the "Done" button or a low enough standard deviation.

Model Validation: Achieving a good history match using this automated regression process increases confidence in the reservoir model's ability to predict future performance and test different production optimization strategies

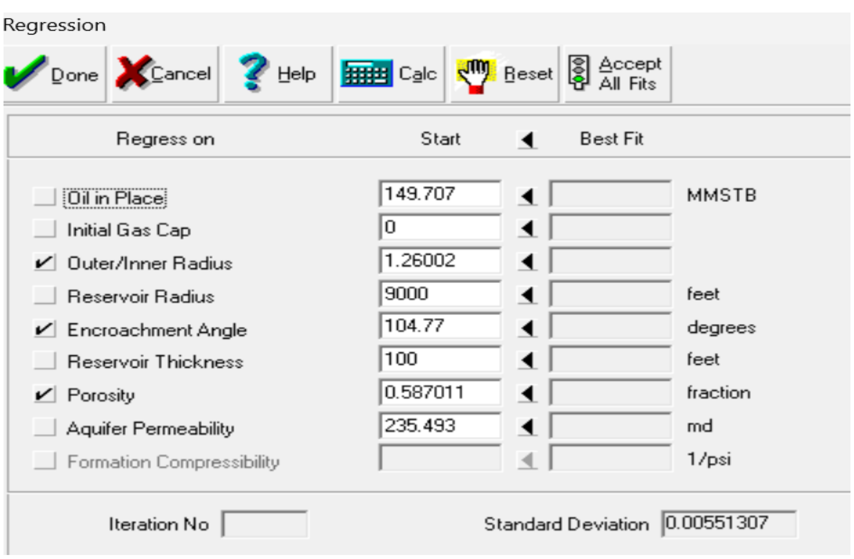


Figure 3.4: Regression section

3.5.8 Drive Mechanism

To determine the dominant reservoir drive mechanism(s) and inform production optimization strategies, a material balance model was developed and history-matched against the field's production and pressure data. The following steps were undertaken:

Data Acquisition: Historical production data (oil, water, gas rates, and reservoir pressure) were collected and analyzed over the operational period from 1987 to 2004.

Material Balance Equation (MBE) Application: The general MBE was applied to the reservoir to quantify the input and output volumes of fluids, considering the reservoir as a tank.

Drive Mechanism Analysis: The relative contributions of energy sources—specifically fluid expansion (oil and connate water expansion), pore volume (PV) compressibility (rock compaction), and water influx from the surrounding aquifer—were calculated over time as the reservoir pressure declined.

Graphical Interpretation: The results, presented in the stacked area in figure 3.5, show that in the early stages, fluid expansion and PV compressibility provided significant energy, but as production continued, water influx became the dominant drive mechanism, supporting reservoir pressure and displacing oil towards the wellbore.

Model Validation: The resulting drive mechanism profile was used to validate the reservoir simulation model and provided a basis for forecasting future reservoir performance and high water cut behavior.

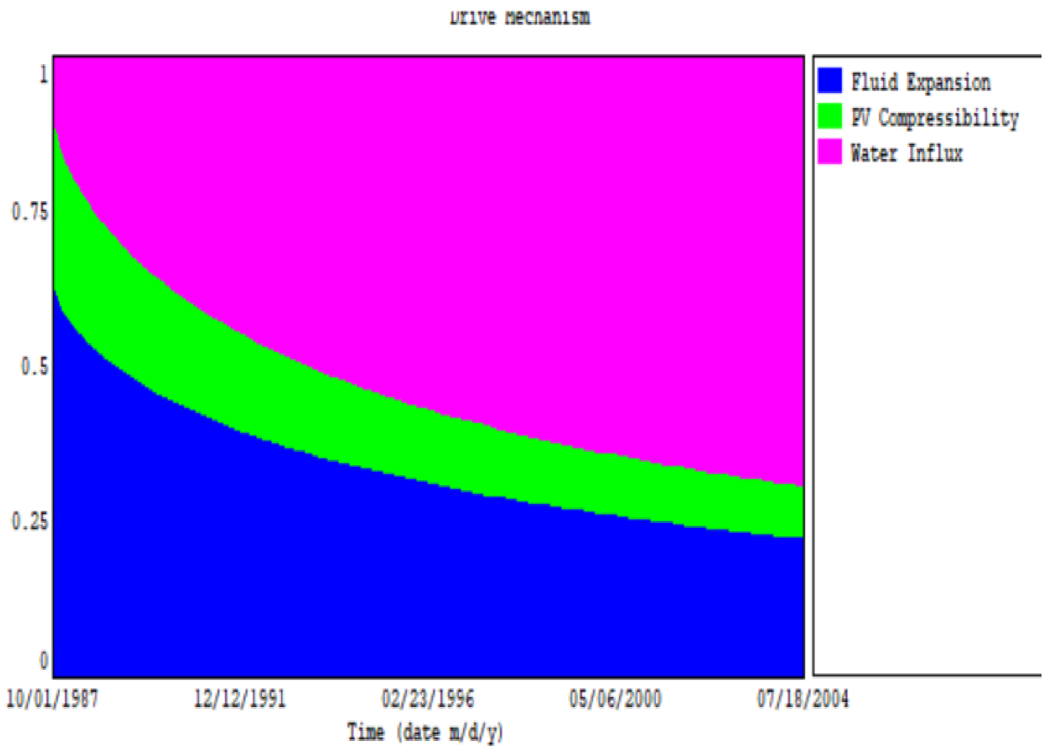


Figure 3.5: Reservoir drive mechanism

3.5.9 History matched plots

The constructed reservoir simulation model was validated against historical field data through a rigorous history matching procedure. The key steps involved were as follows:

Data Compilation: Historical data for key reservoir performance indicators, including reservoir static pressure (as shown in the image), oil and water production rates, and water cut percentages, were gathered for the period from July 1987 to July 2004.

Initial Simulation Run: A preliminary simulation model, built from available geological and petrophysical data, was run to predict the historical performance.

Iterative Parameter Adjustment: Discrepancies between the simulated results and the observed historical data highlighted areas where initial reservoir parameters (such as porosity, permeability, aquifer properties, and fault transmissibilities) were adjusted. This was an iterative process aimed at minimizing the objective function, a statistical measure of the mismatch.

Visual and Quantitative Matching: The history match quality was assessed both visually, by plotting the simulated pressure curve against the actual measured pressure points (as depicted in the figure), and quantitatively, by comparing production rates and water cuts.

Model Acceptance: The figure demonstrates a high degree of correlation between the simulated (red line) and historical (blue squares) tank pressures over the entire 17-year period. This strong alignment indicates that the model accurately reflects the past behavior of the reservoir and is therefore considered validated and reliable for use in future production forecasting and optimization scenarios.

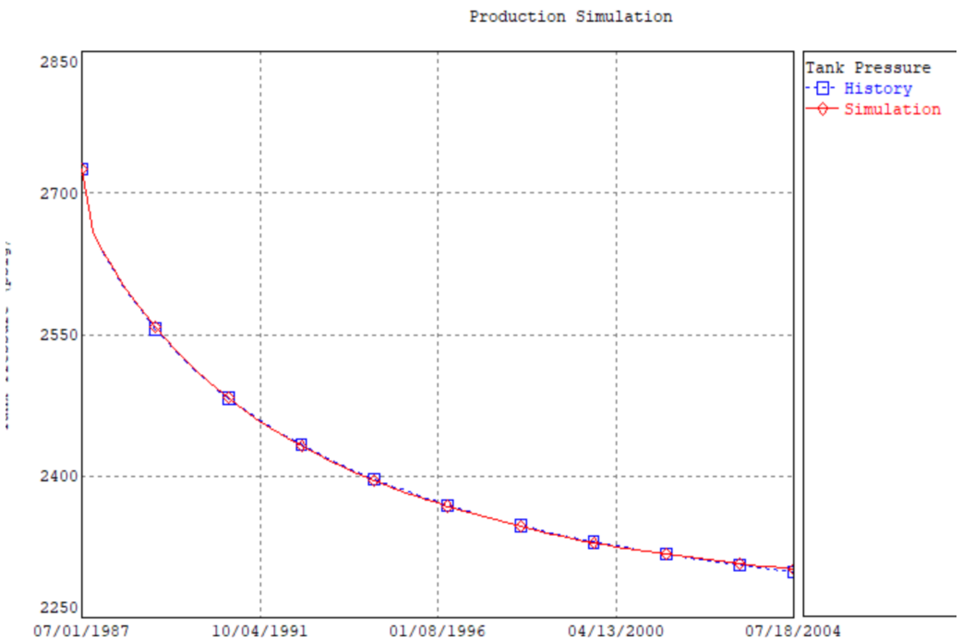


Figure 3.6: History matched fluid pressure history

3.6 Prosper modelling methodology

3 wells were considered in the numerical simulation study. A natural flowing well, a gas lifted well and an electrical submersible pump. The Inflow Performance Relationship (IPR) curve is a fundamental tool for understanding a well's productivity and is essential for designing well completions and production optimization.

3.6.1 Methodology: Well Performance Modeling and Analysis

To evaluate well productivity and determine the optimal production strategy for the mature heavy oil reservoir, a comprehensive well performance model was developed. The methodology involved generating the Inflow Performance Relationship (IPR) curve and integrating it with the wellbore Outflow Performance Relationship (OPR) curve (though only the IPR is shown here).

Data Collection: Required reservoir and fluid properties, including reservoir pressure, temperature, permeability, water cut, skin factor, and wellbore radius (all listed on the right side of the image), were collected from well tests and historical production data analysis.

IPR Model Selection: Based on the reservoir conditions and fluid properties (e.g., the presence of free gas leading to two-phase flow below the bubble point pressure), an appropriate IPR model, such as the Darcy model for single-phase flow or the Vogel/Fetkovich empirical correlations for two-phase flow, was selected and implemented within the simulation software. The image specifies a "Reservoir Model Darcy" and "Inflow Type Single Branch".

IPR Curve Generation: The model was used to plot the relationship between the bottom-hole flowing pressure (Pwf, on the Y-axis) and the corresponding oil production rate (q, on the X-axis). This was achieved by calculating the production rate at various flowing bottom-hole pressures to create the curve shown in the graph. The curve terminates at the Absolute Open Flow (AOF) potential of 4070.5 STB/day when the flowing pressure is zero.

Model Validation: The generated IPR curve was validated using actual field test points to ensure its accuracy in representing the well's real-world inflow capacity.

Application: This IPR curve served as a crucial input for nodal analysis to identify production constraints and for subsequent design and optimization of artificial lift systems to maximize oil recovery.

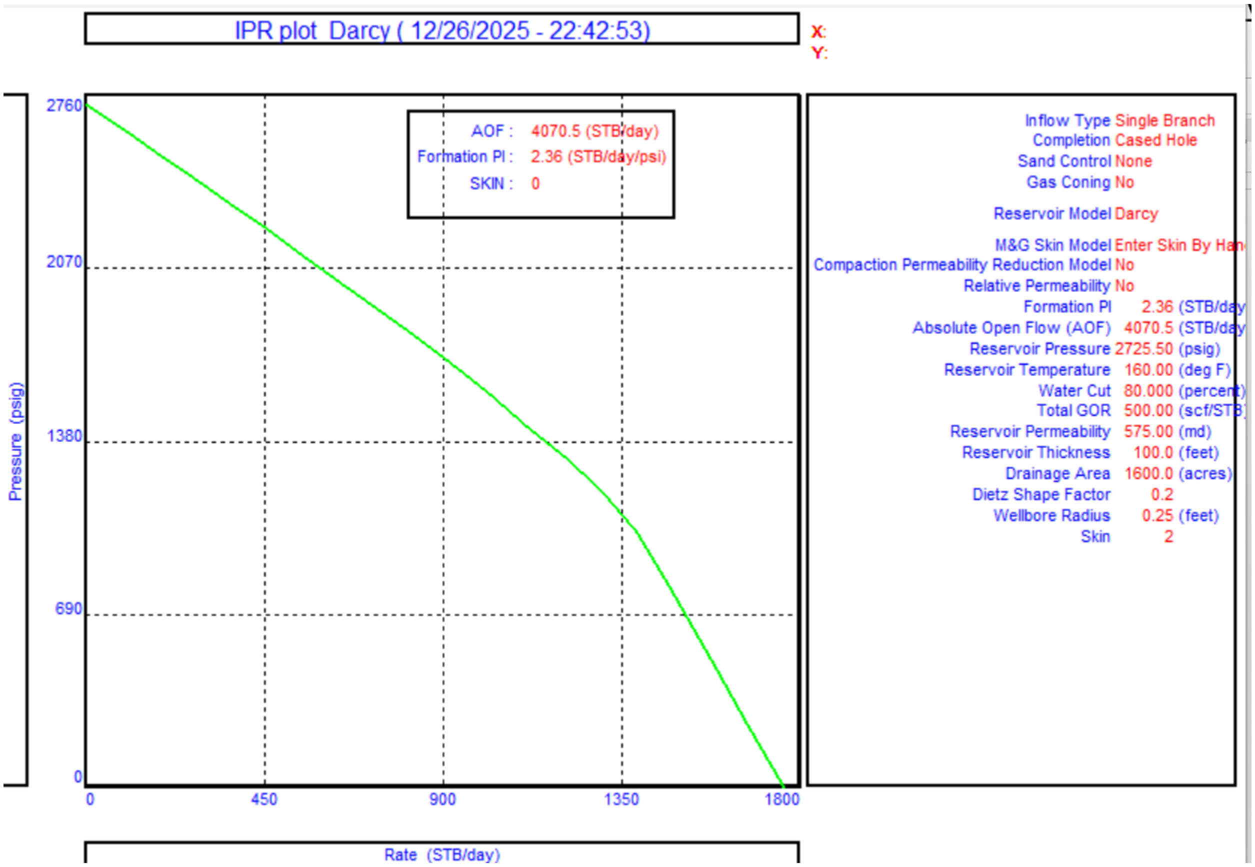


Figure 3.7: IPR relationships, AOF.

Downhole equipment summary

A detailed understanding of the wellbore architecture and downhole equipment configuration is critical for accurate well performance modeling, nodal analysis, and subsequent production optimization efforts. The methodology for incorporating this information into the study involved the following steps:

Wellbore Schematic Development: As illustrated in the figure 3.8, a schematic drawing was generated using well performance software to represent the actual mechanical configuration of the wellbore. This drawing details the specific placement and dimensions of all downhole components, from the Christmas tree at surface to the bottom of the well.

Component Specification: Key components were accurately modeled, including the different casing strings (e.g., 6.79 inches in diameter) and tubing strings (e.g., 2.40 inches in diameter) at their respective Measured Depths (MD) and True Vertical Depths (TVD). This also includes the location of perforations or other inflow points.

Hydraulic Modeling Input: This geometric information and dimensional data were used as fundamental inputs for calculating pressure losses due to friction and changes in elevation within the wellbore, which is a crucial step in Nodal Analysis.

Model Validation: The accurate representation of the downhole equipment ensured that the wellbore model used for simulation was realistic and capable of reliably predicting the well's production performance and identifying potential flow restrictions or integrity issues.

Optimization Baseline: This validated wellbore configuration provided a baseline for evaluating various production optimization scenarios, such as the potential benefits of changing the tubing size, installing an artificial lift system, or performing sand control operations.

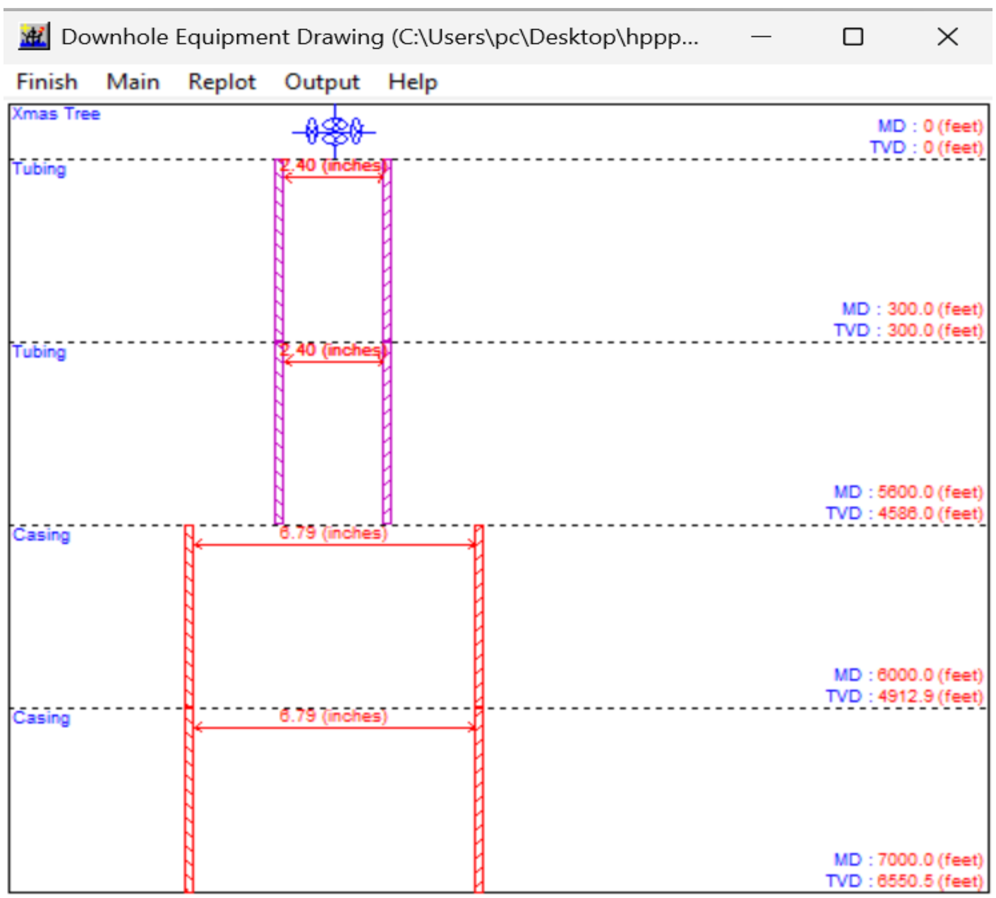


Figure 3.8: Downhole equipment summary

3.6.2 VLP/IPR Matching

The figure 3.9 illustrates the crucial step of collecting and inputting historical well test data for the purpose of validating and calibrating the wellbore model.

Data Entry and Compilation: This interface is where the actual measured field data points are entered or imported from a database. This includes specific data recorded during well tests, such as Tubing Head Pressure (THP), Tubing Head Temperature, Water Cut, Liquid Rate, Gauge Depth, and corresponding Gauge Pressure. The data in the table (e.g., THP of 275 psig, liquid rate of 2000 STB/day, and reservoir pressure of 3720.81 psig) represents a specific operating point recorded on a particular date.

Model Calibration (Matching): The primary importance of this step is to match the theoretical well performance curves (Inflow Performance Relationship/IPR and Vertical Lift Performance/VLP) to these real-world data points. The software adjusts its internal multiphase flow correlations and reservoir parameters until the calculated pressures and rates align closely with the observed field measurements. The "Match VLP" and "Adjust IPR" buttons shown in the tasks section are used to initiate these calibration procedures.

Importance: This data matching process is essential because it builds a reliable and consistent well model that accurately reflects the actual well and reservoir behavior under various conditions. A validated model is then used to perform sensitive analyses on key parameters (e.g., tubing size, GOR, water cut) and to confidently design and optimize artificial lift systems, which is the core of production optimization work for a mature field with high water cut

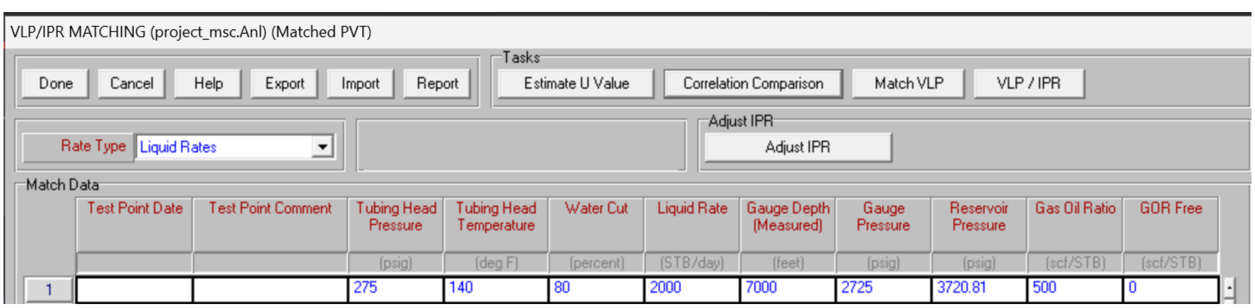


Figure 3.9: VLP/IPR matching for a calibrated model

The figure 3.10 displays an input screen from well performance modeling software, PROSPER from Petroleum Experts. The interface is specifically for a "Tubing Correlation Comparison" where users input measured well test data and select different multiphase flow correlations to calculate pressure drops along the wellbore.

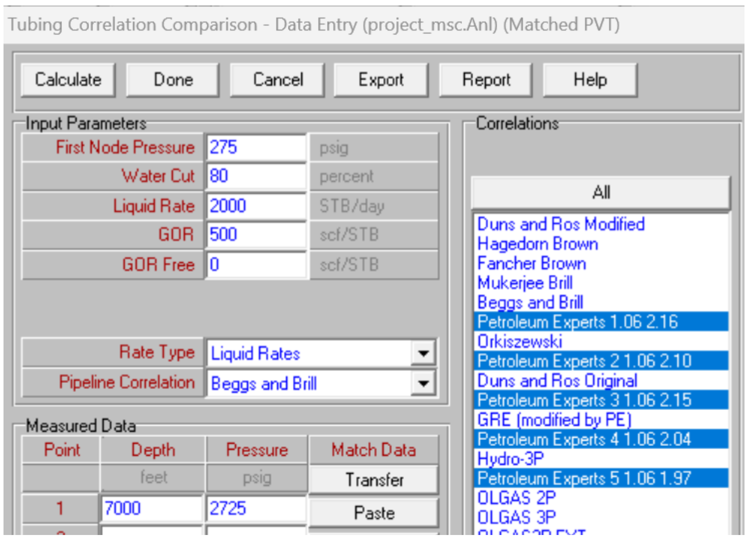


Figure 3.10: Tubing correlation comparison

The screen is divided into several key sections:

Input Parameters: This section is used to define the fluid and flow properties at a specific point in the production system, such as the First Node Pressure (275 psig), Water Cut (80%), Liquid Rate (2000 STB/day), and GOR (500 scf/STB).

Correlations: A list of various empirical and mechanistic multiphase flow correlations is provided (e.g., Beggs and Brill, Duns and Ros, Hagedorn Brown, Petroleum Experts correlations), from which the user can select one to model the fluid flow in the pipeline.

Measured Data: A table at the bottom allows for the input of actual field test data points, including the Depth and corresponding Pressure measurements (e.g., 7000 feet depth and 2725 psig pressure). This real-world data is crucial for the calibration process.

The significance of this interface in the context of production optimization work is model validation and calibration.

Model Accuracy: No single multiphase flow correlation works perfectly for all field conditions (e.g., high water cut, different flow regimes). This screen allows engineers to compare how well different correlations predict the actual measured pressure profile of a specific well.

Best-Fit Selection: By comparing the calculated pressure values to the field data, the engineer can select the "best-fit" correlation for that particular well. This validated correlation is then used for all future performance predictions and sensitivity analyses (e.g., analyzing the impact of tubing size or gas injection).

Reliable Optimization: Using a calibrated, reliable well model ensures that any subsequent optimization decisions (such as the design of artificial lift systems to handle high water cuts) are based on accurate data, thus maximizing the chances of success in increasing oil recovery.

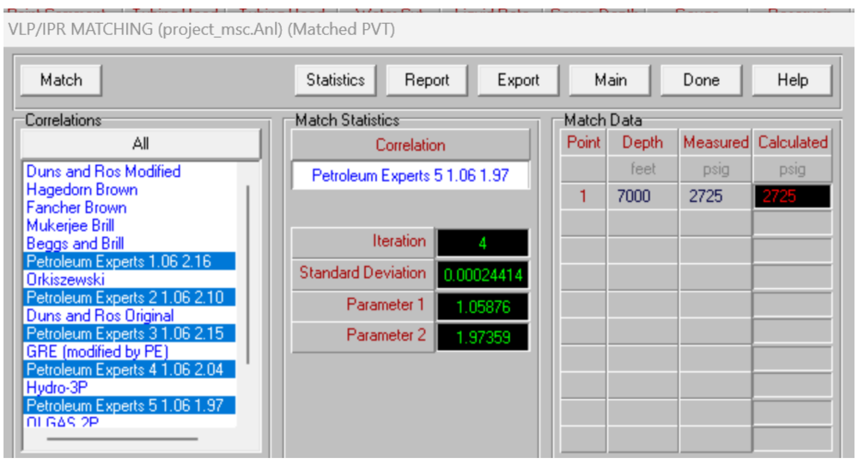


Figure 3.11: VLP/IPR matching screen

The screen provides a quantitative summary of the history matching for vertical lift performance:

Correlations List: The left panel lists several industry-standard multiphase flow correlations, such as Beggs and Brill, Hagedorn Brown, and Duns and Ros, which are used to model pressure drop in the wellbore.

Match Statistics: The center panel shows the results of an automated matching process. The "Standard Deviation" (0.00024414) is a statistical measure of the goodness of fit between the calculated pressures (using the selected correlation) and the actual measured field data. Lower values indicate a better match.

Tuning Parameters: The "Parameter 1" and "Parameter 2" are tuning parameters (multipliers for gravity and friction terms, respectively) that the software adjusts during the matching process to fine-tune the selected correlation to the specific well's performance. Ideally, these parameters should be close to 1.0, and the values shown are close to this ideal.

Match Data: The right panel compares the single "Measured" pressure point (2725 psig at 7000 feet) to the "Calculated" pressure point (2725 psig) after matching, highlighting a near-perfect fit for this specific data point.

The significance of this process is that it ensures the reliability and accuracy of the well model. Since no single correlation works for all field conditions, this matching step allows the engineer to calibrate the model to actual field performance. A validated, tuned model can then be confidently used for future production forecasting and sensitivity analyses, which are crucial for designing and optimizing artificial lift systems or determining the most effective strategies to maximize oil recovery in a mature reservoir with high water cut

The figure 3.12 displays the interface of a well performance modeling and analysis software, PROSPER from Petroleum Experts, during the "VLP Matching - IPR Adjust" stage.

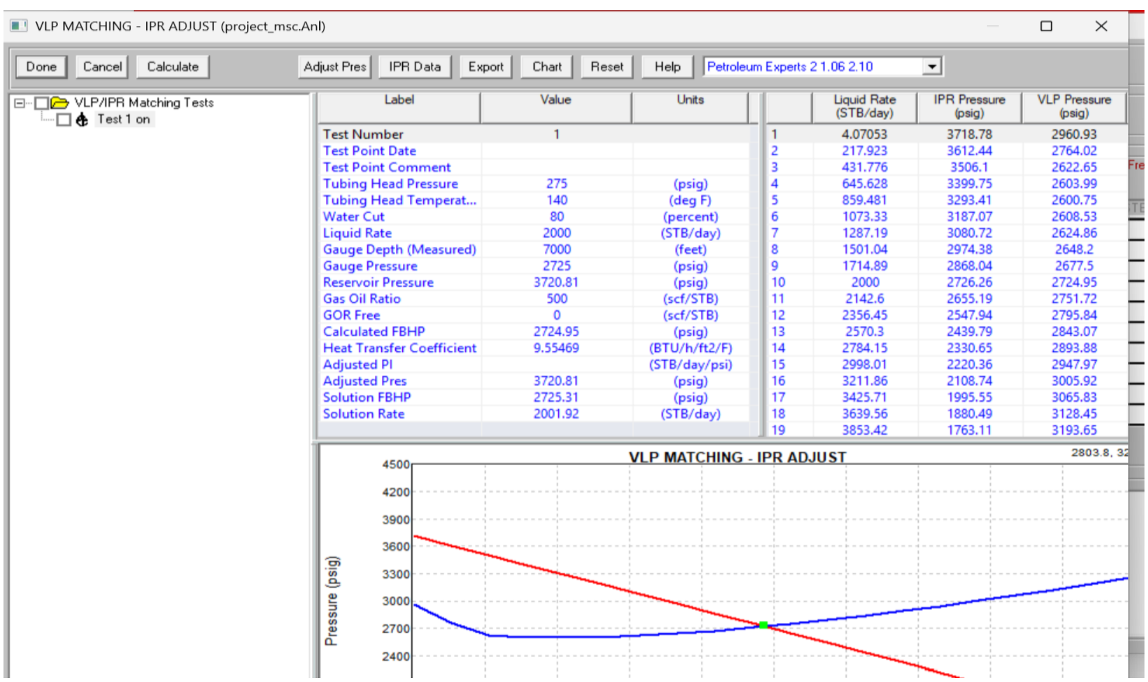


Figure 3.12: VLP/IPR matching screen – Adjust IPR section

Description

This screen is a data-driven interface for calibrating a wellbore model. It presents:

Well Test Data: A table on the right side lists various measured and calculated parameters for a specific test point, including Tubing Head Pressure (275 psig), Liquid Rate (2000 STB/day), Water Cut (80 percent), Gauge Depth (7000 feet), and Gauge Pressure (2725 psig). These are real-world field measurements.

Calculated Results: The lower part of the table shows results derived from the software's internal model, such as the "Calculated FBHP" (Flowing Bottom Hole Pressure) and the "Solution Rate" after a successful match.

IPR/VLP Graph: The graph at the bottom right visually represents the Inflow Performance Relationship (IPR, the blue curve) and the Vertical Lift Performance (VLP, the red line) curves. The intersection of these two curves represents the actual operating point of the well under the current conditions.

Significance

The primary significance of this interface and process in production optimization work is well model validation and accuracy.

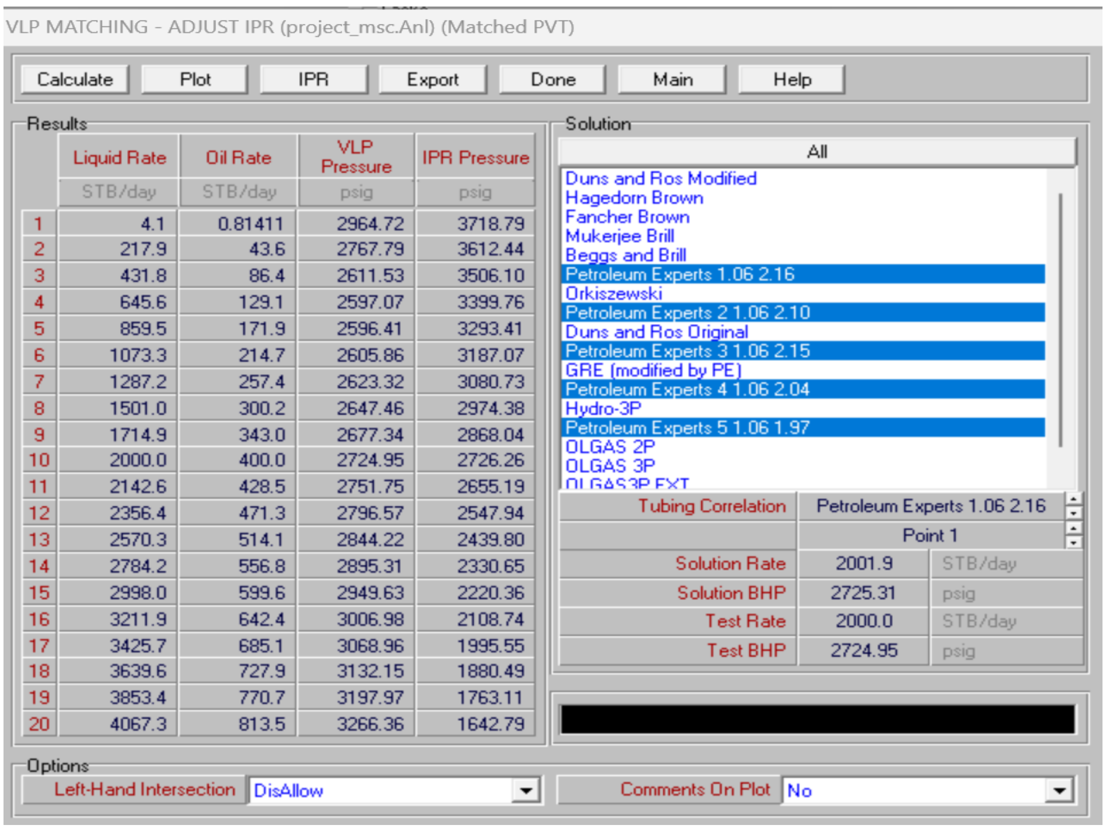
Model Calibration: The ability to "Match VLP" and "Adjust IPR" against real field test data is crucial. This process allows engineers to tune the complex multiphase flow correlations and reservoir parameters within the software to accurately reflect the unique behavior of the specific well.

Reliable Forecasting: A model that has been successfully calibrated and validated against historical data provides a reliable foundation for performing sensitivity analyses, diagnosing well performance issues, and predicting future production under various scenarios (e.g., changes in water cut, reservoir pressure, or artificial lift installations).

Informed Decision Making: The accurate operating point determined by the intersection of the matched IPR and VLP curves ensures that any decisions regarding production optimization strategies are based on sound engineering principles and realistic field performance data, thus maximizing potential oil recovery from the mature reservoir.

3.7 VLP/IPR Matching

The image 3.13 displays the results of a Vertical Lift Performance (VLP) and Inflow Performance Relationship (IPR) matching process, typically conducted using reservoir and production engineering software such as PROSPER.



	Liquid Rate	Oil Rate	VLP Pressure	IPR Pressure
	STB/day	STB/day	psig	psig
1	4.1	0.81411	2964.72	3718.79
2	217.9	43.6	2767.79	3612.44
3	431.8	86.4	2611.53	3506.10
4	645.6	129.1	2597.07	3399.76
5	859.5	171.9	2596.41	3293.41
6	1073.3	214.7	2605.86	3187.07
7	1287.2	257.4	2623.32	3080.73
8	1501.0	300.2	2647.46	2974.38
9	1714.9	343.0	2677.34	2868.04
10	2000.0	400.0	2724.95	2726.26
11	2142.6	428.5	2751.75	2655.19
12	2356.4	471.3	2796.57	2547.94
13	2570.3	514.1	2844.22	2439.80
14	2784.2	556.8	2895.31	2330.65
15	2998.0	599.6	2949.63	2220.36
16	3211.9	642.4	3006.98	2108.74
17	3425.7	685.1	3068.96	1995.55
18	3639.6	727.9	3132.15	1880.49
19	3853.4	770.7	3197.97	1763.11
20	4067.3	813.5	3266.36	1642.79

Figure 3.13: VLP/IPR matching screen – Solution details

The interface presents a table comparing different empirical and mechanistic multiphase flow correlations (e.g., Beggs and Brill, Duns and Ros, Hagedorn Brown) used to model fluid flow from the bottom of the well to the surface. The core data includes:

Flow Rates and Pressures: Columns detail the liquid and oil rates in STB/day, and corresponding VLP and IPR pressures in psig.

Correlation Performance: The software calculates how well each correlation performs against specific, measured field test data (indicated by "Test Rate" of 2000 STB/day and "Test BHP" of 2724.95 psig), often by adjusting internal tuning parameters to find the best fit.

Operating Point: The results show the intersection of the IPR and VLP curves, which defines the well's actual stable operating point under the given conditions ("Solution Rate" 2001.9 STB/day, "Solution BHP" 2725.31 psig).

Significance

The significance of this process in production optimization work is model calibration and validation.

Enhanced Model Accuracy: By comparing multiple correlations against real-world field data, engineers can select the most appropriate and accurate model for that specific well's unique fluid properties and flow conditions (e.g., high water cut in a mature reservoir). This ensures the simulation accurately represents reality.

Reliable Decision Making: A calibrated and validated well model provides a reliable foundation for subsequent sensitivity analyses and design decisions. This is critical for confidently evaluating and implementing production enhancement strategies, such as selecting the optimal tubing diameter, designing artificial lift systems (e.g., gas lift), or assessing stimulation treatments to maximize oil recovery efficiently and economically.

Performance Diagnostics: The comparison highlights potential discrepancies between theoretical models and field performance, which helps in diagnosing specific wellbore or reservoir issues, ultimately leading to more effective optimization plans.

3.8 Natural flowing well IPR vs VLP

The image displays a screenshot of a technical graph titled "Inflow (IPR) – Outflow (VLP) Plot". The graph contains multiple green and red curves plotted against axes, and a data table is partially visible below the main plot area.

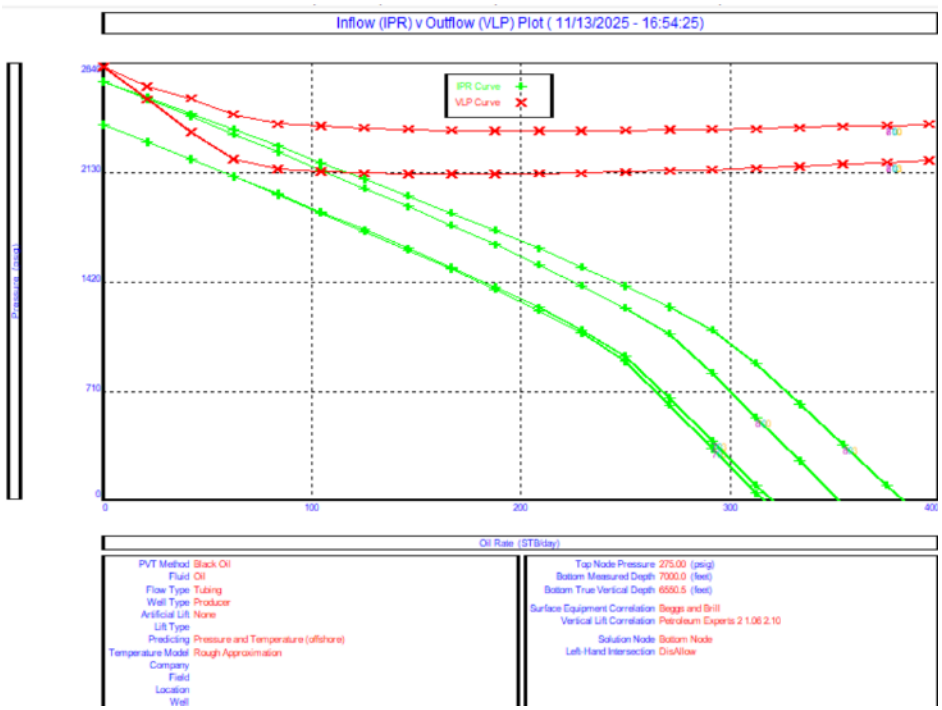


Figure 3.13: VLP/IPR matching screen – Solution details

The graph is a standard tool used in petroleum engineering and production analysis to model and optimize the performance of oil and gas wells.

IPR (Inflow Performance Relationship) curves (the green curves) typically show the relationship between the flow rate of a well and the bottomhole flowing pressure.

VLP (Vertical Lift Performance) or Outflow curves (the red curves) show the relationship between the flow rate and the required bottomhole pressure to lift the fluid to the surface.

Significance: The intersection points of the IPR and VLP curves indicate the actual operating conditions (flow rate and pressure) of the well. Engineers use these plots to:

Select artificial lift methods: Determine the most efficient way to enhance production, such as using gas lifting or electric submersible pumps (ESP).

Optimize production: Analyze how changes in reservoir conditions or equipment affect the well's output.

Predict performance: Forecast future production rates and recovery factors for the field.

3.8.1 Gas lifted well

The figure 3.14 is a screenshot of a specialized software interface used for petroleum engineering applications PROSPER, specifically for designing and analyzing gas lift systems in oil and gas wells

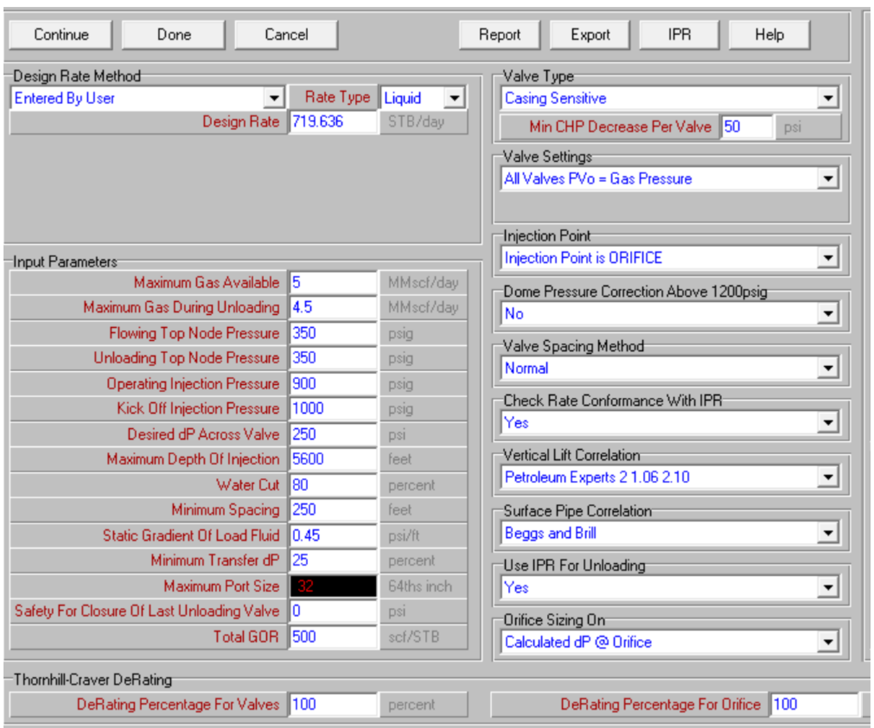


Figure 3.14: Gas lift design input parameters

Input Parameters: The interface allows users to input specific well and fluid characteristics, such as maximum gas availability, flowing tubing pressure, unloading pressures, injection pressures, and minimum spacing.

Valve Settings: Parameters related to the gas lift valves, including type, settings, and orifice size, are configurable.

Methodology and Correlations: Users can select different calculation methods and vertical lift correlations, such as “Petroleum Experts 21.06.210” and “Beggs and Brill,” to model fluid flow within the wellbore.

Additional Options: Checkboxes for options like “Use IPR for Unloading” and “ESP lifted well” are visible, indicating flexibility in modeling different well scenarios. The parameters above show the gas lift design parameters used in the simulation of gas lift system.

The design rate was set at 720stb/d.

The maximum injection depth was set at 5600ft.

Valve depths

Valve 1 = depth at 1530ft

Valve 2 = depth at 2332ft

Valve 3 = depth 2674ft

The solution details:

Liquid rate = 719.6b/d, oil rate = 173b/d

Injected gas rate = 1.7mmscf/d

Injection pressure = 900psi

The significance of this software lies in its ability to accurately model and optimize artificial lift operations. It allows engineers to design efficient gas injection strategies, select appropriate equipment, and predict well performance, ultimately maximizing hydrocarbon production from a given wellbore.

3.8.2 ESP lifted well

The Figure 3.15 displays an interface for an Electric Submersible Pump (ESP) design and modeling. This software allows engineers to input specific well and fluid data to simulate and design an efficient artificial lift system.

Technical Description of the ESP Modeling Interface

The interface captures critical input data for the design process: Well and Pump Parameters: Pump depth: 3100feet (measured). Operating Frequency: 60 Hertz, a standard for oilfield applications.

Maximum OD: 5.62 inches, a constraint for the well casing size. Length of Cable: 6200 feet. Fluid and Flow Parameters: Design Rate: 3400 STB/day (Stock Tank Barrels per day), the target production volume. Water Cut: 80 percent, indicating a high water production ratio. Total GOR (Gas-Oil Ratio): 500 scf/STB (standard cubic feet per stock tank barrel). Top Node Pressure: 350 psig, Modeling Correlations and Efficiencies: Gas Separator Efficiency: 50 percent.

The presence of gas at the pump intake is a major factor in ESP performance, requiring modeling of gas separation or handling. Pipe Correlation: Beggs and Brill, a common multiphase flow correlation. Tubing Correlation: Petroleum Experts 21.06 210.

Importance of ESP Modeling

ESP modeling is a critical engineering tool in the oil and gas industry. Its importance stems from several factors: Efficiency and Optimization: Accurate modeling allows engineers to select the correct pump size, stages, and motor to match specific well conditions, maximizing hydrocarbon extraction efficiency and minimizing energy consumption.

Handling Multiphase Flow: The ability to model the effects of free gas (using correlations like Beggs and Brill and gas derating models) is crucial, as gas can severely impact pump performance and lead to gas locking. Design Validation: Simulation models help in validating design choices before expensive equipment is installed downhole, reducing operational risks and costs. Performance Prediction: The software predicts how the ESP system will perform under varying conditions (e.g., different flow rates, water cuts, or frequencies), allowing for better production management and troubleshooting.

The artificial lift system was designed with a target rate of 3400stb/d.

The length of cable is 6200ft, 100ft from the pump set depth to allow for expansion and contraction of the ESP cable system due to temperature differences.

The Well head pressure is set at 350psi.

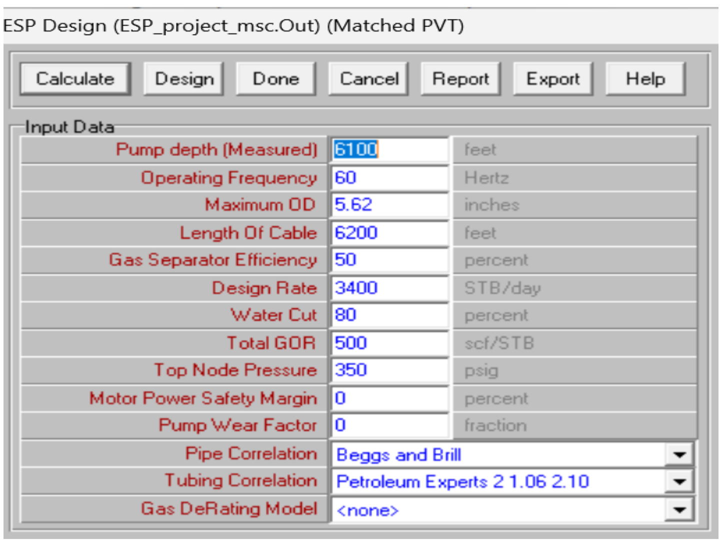


Figure 3.15: ESP Design parameters

3.8.3 Gap model

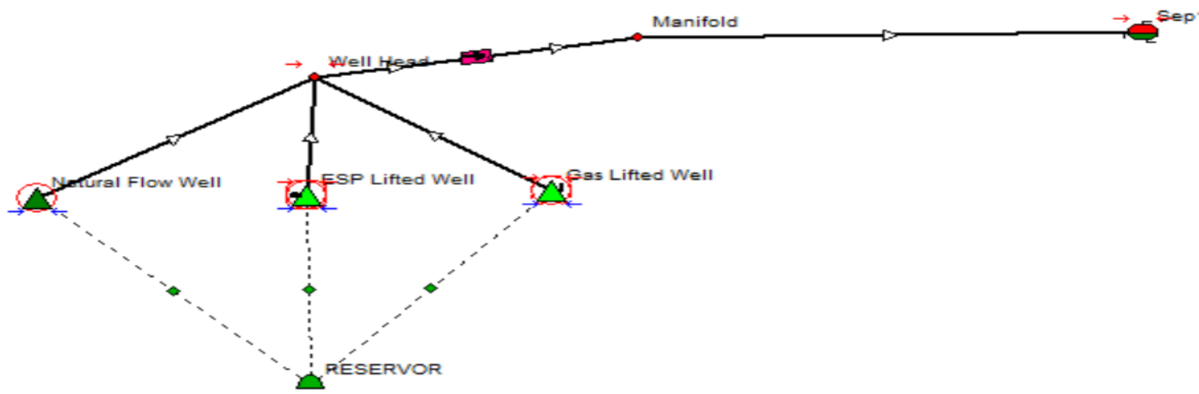


Figure 3.16: Gap Network Model

The image 3.16 is a schematic of a production network model, created using a software like GAP (General Allocation Program) for petroleum engineering.

Model Description: The diagram illustrates a system where fluids (oil, gas, water) flow from a central Reservoir to different types of production wells: a Natural Flow Well, an ESP Lifted Well (using an Electric Submersible Pump), and a Gas Lifted Well (using injected gas to aid flow). These flow lines converge at a Manifold before the commingled stream is directed to a Separator.

Significance: Such models are typically used to simulate and optimize the flow of hydrocarbons from the reservoir to the surface facilities. They help engineers:

Predict production rates under various operating conditions.

Identify flow bottlenecks within the system.

Optimize artificial lift performance and manifold pressures.

Allocate production from the common manifold back to individual wells for reporting and reservoir management purposes.

Gap model for the wells.

The interface allows engineers to input parameters that govern how fluids flow from the reservoir into the wellbore:

Layer Selection: The "Layer 1 - OK" tab allows for the management of different producing zones or layers within the reservoir.

Inflow Performance Section: This is where the core reservoir properties and IPR model are defined.

IPR Type: The model selected here is "Straight Line + Vogel". This is a generalized model often used for oil wells where the flowing bottom-hole pressure may drop below the bubble point pressure, causing gas to come out of solution in the reservoir. The straight line portion applies above the bubble point, and the Vogel correlation is used below it.

P.I.: The Productivity Index (PI) value (2.1511861 STB/day/psi) is a key measure of the well's ability to produce fluids. For a naturally flowing well, a sufficient PI is necessary to push fluids to the surface without artificial lift.

Layer Pressure & Temp: The average reservoir pressure (2725.5 psig) and temperature (160 deg F) are essential inputs for fluid property calculations.

Fluid Properties Section: This section defines the composition and physical characteristics of the fluids in the well.

Oil Gravity (API 37), Gas Gravity (0.68 sp. gravity), GOR (500 scf/STB), and Water Cut (WCT 80.000001 percent): These parameters are critical for calculating pressure losses and fluid behavior in the wellbore, especially the impact of high water cut on the overall fluid density and viscosity.

This interface is the foundation for modeling a naturally flowing well. The significance lies in its ability to:

Define Flow Potential: The inputs here directly determine the well's theoretical maximum flow rate, known as the Absolute Open Flow (AOF), and the entire Inflow Performance Relationship curve.

Enable Nodal Analysis: The IPR data from this screen is combined with the Vertical Lift Performance (VLP) model (which describes pressure drop in the wellbore tubing) through Nodal Analysis. The intersection of these two curves identifies the actual, stable operating point (flow rate and pressure) of the natural flowing system.

Assess Flow Feasibility: For a well to flow naturally, the reservoir pressure must be high enough and the pressure losses in the wellbore low enough to push fluids all the way to the surface facilities. This interface allows engineers to verify these conditions before any physical equipment changes are made

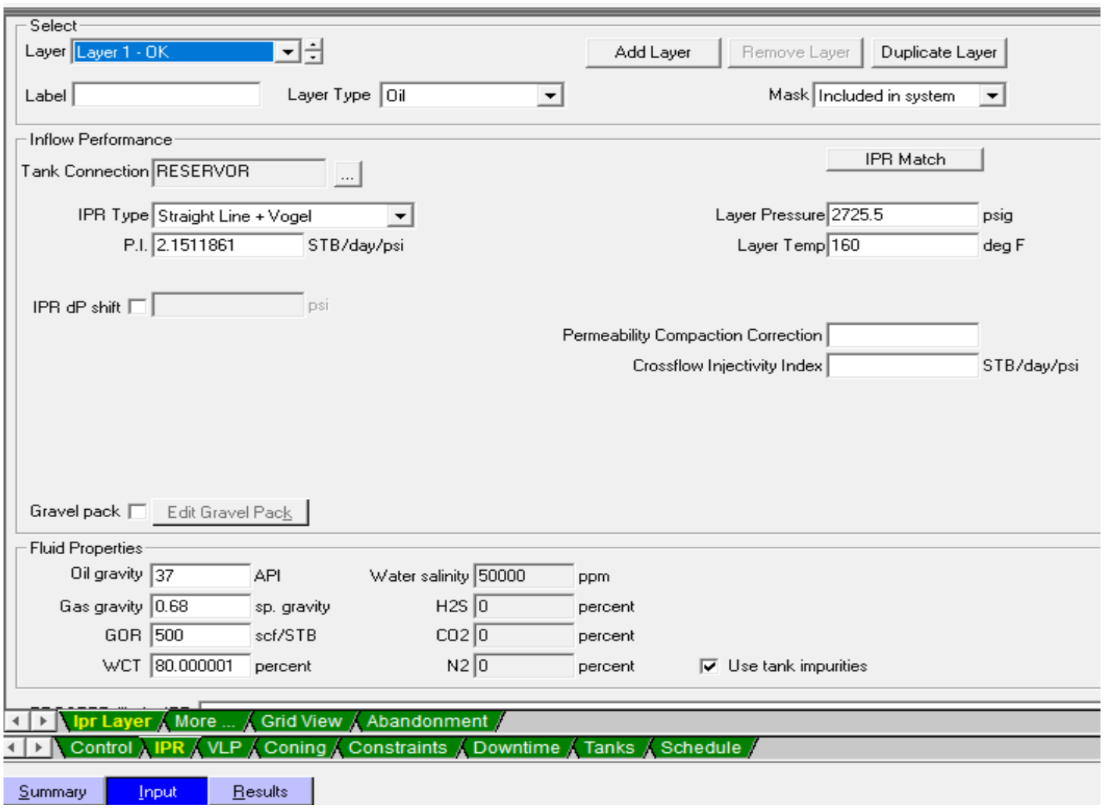


Figure 3.17: Data input screen for Gap modelling

3.8.4 Environmental variables

Accurate modeling of fluid temperature profiles along the wellbore and flowlines is crucial for calculating fluid physical properties (e.g., density and viscosity) which in turn affect pressure drop calculations. The methodology for incorporating thermal aspects involved the following steps:

Environmental Data Collection: The average Surrounding Temperature (50 deg F) was determined from field data to represent the external conditions the pipe is exposed to, such as air temperature or seabed temperature.

Heat Transfer Coefficient Determination: An Overall Heat Transfer Coefficient (U-value of 8 BTU/h/ft^2/F) was estimated or calculated for the specific wellbore or pipeline configuration (e.g., bare pipe, insulated pipe, pipe-in-pipe) to quantify the rate of heat exchange with the surroundings.

Fluid Heat Capacity Measurement: The specific Heat Capacity values for the different fluid phases (Oil 0.53, Gas 0.51, Water 1 BTU/lb/F) were obtained from laboratory analysis of fluid samples to correctly model the enthalpy changes as fluids flow up the wellbore.

Significance in Production Optimization

The significance of these parameters is flow assurance and model accuracy.

Flow Assurance: Accurate temperature modeling is critical for preventing flow assurance issues like the precipitation and deposition of asphaltenes or wax, which can severely restrict flow and increase pressure drop, especially in high-pressure, high-temperature (HPHT) systems or subsea environments.

Accurate Pressure Modeling: Temperature and pressure are coupled; temperature variations significantly influence fluid density and viscosity, which are direct inputs for pressure drop calculations using multiphase flow correlations.

Reliable Optimization: By using these calibrated thermal inputs, the overall wellbore model becomes more reliable. This allows engineers to confidently evaluate and design production optimization strategies, such as selecting appropriate insulation for pipelines or designing artificial lift systems for heavy oil production, to maximize oil recovery and ensure wellbore integrity.

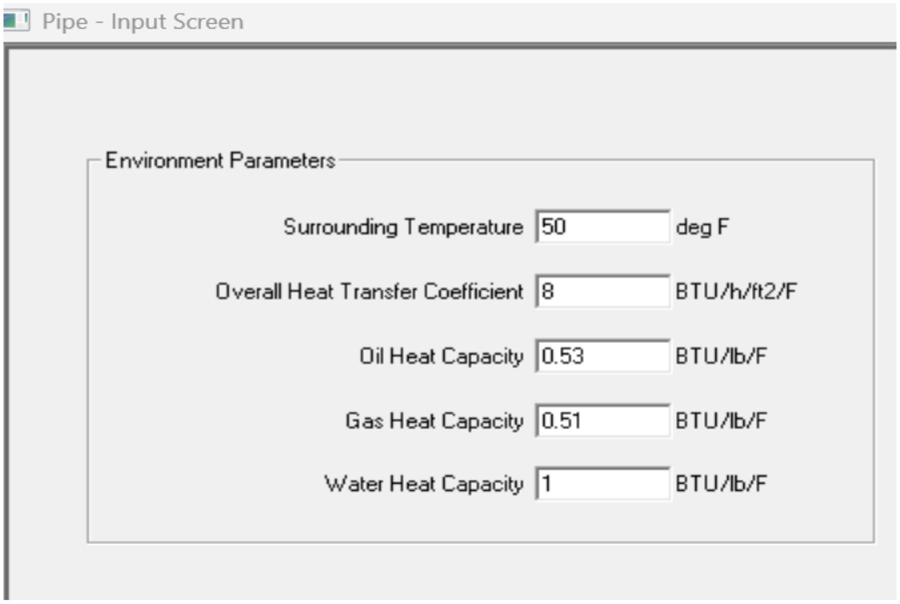


Figure 3.18: Setting environment variables

3.8.5 Constraints

Constraints are the global limits that control how the entire surface + subsurface network behaves during optimization.

They define the operational envelope of the field, including:

Maximum/minimum allowable pressures

Limits on processing facilities

Available lift gas, water injection, or export capacity

Well deliverability limits

Artificial lift limits (e.g., gas-lift injection pressure, gas-lift gas availability)

Constraints

Gas lifted well: Gas injection rate: 1.5MMscf/d, gas gravity = 0.7 and the pressure drop is 32psi

ESP lifted well: Pump frequency, minimum and maximum value at 60 and 70Hz respectively, pressure drop is 32psi

Natural flowing well: Pressure drop set at 32psi

RESULTS AND DISCUSSIONS

4.1 Case 1: Natural flowing well

Sensitivity analysis.

Sensitivity analysis is a technique used to determine how changes in input variables or parameters of a model affect its output or results. It is a "what-if" analysis that systematically varies one or more input parameters to observe the corresponding changes in the output (e.g., oil production rate, cumulative oil recovery, or net present value).

Impact on Production Optimization

Sensitivity analysis has a significant impact on production optimization in petroleum engineering by providing critical insights that inform decision-making, manage risk, and improve model reliability. Its key impacts include:

Identifying Key Variables: It helps identify which reservoir or operational parameters have the most significant influence on production performance. For a mature heavy oil reservoir with high water cut, this might reveal whether water cut, reservoir pressure, or wellbore fluid properties (like viscosity) are the dominant factors affecting oil recovery.

Focusing Efforts and Resources: By pinpointing the most sensitive parameters, engineers can focus their efforts on obtaining more accurate data for those specific variables (e.g., through detailed well testing or lab analysis), thus saving time and computational costs associated with less influential factors.

Managing Uncertainty and Risk: The analysis helps to understand the range of possible outcomes given the inherent uncertainties in reservoir data and assumptions. This allows for a better assessment of project risk and the development of robust contingency plans to mitigate potential negative impacts.

Model Calibration and Validation: It is used during the history matching and model calibration process to ensure the simulation model accurately reflects real-world behavior. Matching calculated well pressures and rates to measured data points (as seen in previous images) is a form of this validation.

Informed Decision Making: Ultimately, sensitivity analysis empowers decision-makers to make more informed and confident choices about optimization strategies, such as selecting the optimal artificial lift system, choosing the most effective EOR method, or designing well completions to maximize economic efficiency and oil recovery.

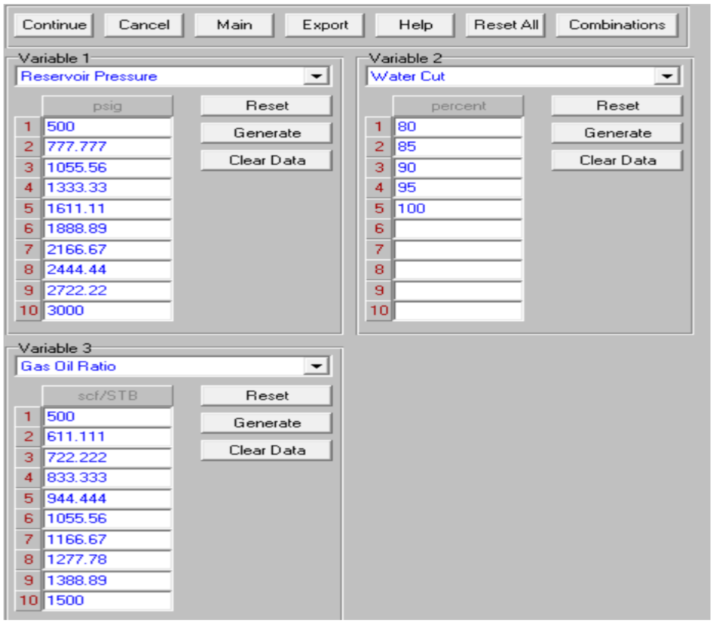


Figure 4.1: Sensitivity analysis screen

The image 4.2 below displays the tabular results from a Nodal Analysis calculation within well performance modeling software, presenting a detailed breakdown of flow conditions along the production string for various operating points. This data is the direct output of the validated well model discussed in previous steps and is crucial for making informed production optimization decisions for the mature heavy oil reservoir.

The table provides a sequential list of solutions (rows 1 through 14), corresponding to different flow conditions from zero flow up to maximum potential flow. Key elements are explained below:

Input Variables: The 'Variables' box confirms the operating conditions for which these calculations were performed: Reservoir Pressure (2166.67 psig), Water Cut (80 percent), and Gas Oil Ratio (1055.56 scf/STB). These are typical values for a mature heavy oil field.

Flow Rates: The first two columns detail the calculated Liquid Rate (total fluid) and Oil Rate in STB/day for each solution point. These are primary metrics for evaluating the well's productivity potential. For example, at row 6, the well can produce 522.46 STB/day total liquid, yielding 104.49 STB/day of oil.

VLP Pressure (Outflow): This column shows the pressure required at the bottom of the well to lift the fluid column to the surface at the corresponding liquid rate. The pressure decreases as flow rate increases due to friction losses becoming dominant over static head changes at high rates (e.g., from 2816.91 psig at low flow to 1985.25 psig at row 6).

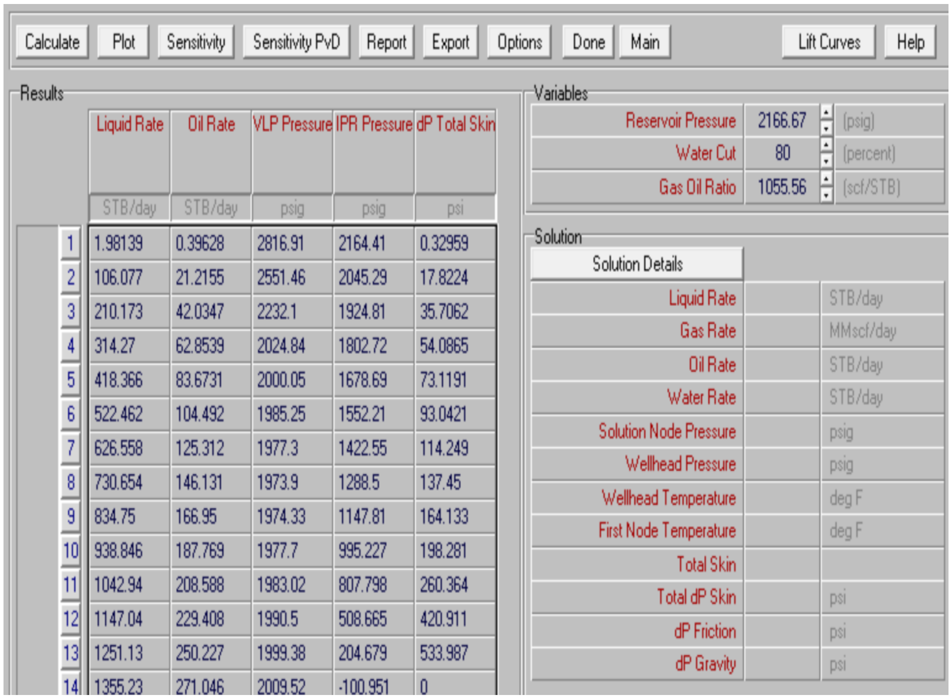
IPR Pressure (Inflow): This column shows the flowing bottom-hole pressure (FBHP) at which the reservoir can supply the corresponding liquid rate. This pressure decreases as the flow rate increases due to increased pressure drop in the near-wellbore region (e.g., from 2164.41 psig at low flow to 1552.21 psig at row 6).

Operating Point Identification: The actual operating point of the well is found where the VLP Pressure equals the IPR Pressure. In this table, the closest match occurs around row 6 or 7, indicating the well is naturally flowing at approximately 520-620 STB/day of total liquid under these specific reservoir conditions.

Skin Factor (Total Skin): This column provides the calculated dP Total Skin in psi, which quantifies any additional pressure losses near the wellbore due to damage, completion, or stimulation. Higher values (e.g., 93.04 psi at row 6) indicate significant pressure losses and potential for stimulation opportunities to increase the Productivity Index (PI).

This detailed breakdown allows engineers to precisely quantify the well's performance under current conditions, diagnose flow limitations (e.g., high skin), and evaluate the potential impact of various production optimization strategies before field implementation.

The table on the right hand side showing solution details shows that no solution for the system was obtained at the reservoir conditions of pressure, water cut and GOR. At a pressure of 2166psi, 80% water cut and a higher GOR of 1055scf/stb, the reservoir could not provide sufficient energy to cause the vertical lift of oil to the surface. Artificial lift required to lift the crude oil from the well to the surface.



	Liquid Rate (STB/day)	Oil Rate (STB/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)
1	1.98139	0.39628	2816.91	2164.41	0.32959
2	106.077	21.2155	2551.46	2045.29	17.8224
3	210.173	42.0347	2232.1	1924.81	35.7062
4	314.27	62.8539	2024.84	1802.72	54.0865
5	418.366	83.6731	2000.05	1678.69	73.1191
6	522.462	104.492	1985.25	1552.21	93.0421
7	626.558	125.312	1977.3	1422.55	114.249
8	730.654	146.131	1973.9	1288.5	137.45
9	834.75	166.95	1974.33	1147.81	164.133
10	938.846	187.769	1977.7	995.227	198.281
11	1042.94	208.588	1983.02	807.798	260.364
12	1147.04	229.408	1990.5	508.665	420.911
13	1251.13	250.227	1999.38	204.679	533.987
14	1355.23	271.046	2009.52	-100.951	0

Figure 4.2: Solution details

The plot 4.3 below incorporates sensitivity analyses on Reservoir Pressure and Water Cut, as detailed in the 'Variables' section, to demonstrate performance across various conditions.

Reservoir Pressure 3000 psig down to 500 psig Declining reservoir pressure shifts the IPR curves to the left and downwards, significantly reducing flow potential. Decision: The sharp decline necessitates implementing pressure maintenance strategies (e.g., water or gas injection) to maintain pressure above the critical point of ~1700 psig and sustain economic rates.

Water Cut 0% up to 100% Increasing water cut (WC) primarily impacts the VLP curve by increasing the fluid density, which increases the hydrostatic pressure drop and shifts the VLP curves upwards and to the left (requiring a higher bottomhole pressure for the same rate). Decision: High water cuts, as seen in the later curves, confirm the need for efficient water handling facilities and potentially a change in artificial lift method to manage the heavier fluid column.

Specific Operating Points and Decisions:

Current/Early Life (High Pressure, Low Water Cut): Using values from the right side of the plot (e.g., near 3000 psig reservoir pressure and 0% WC), the intersection point is at a high liquid rate (e.g., >4000 STB/day) and low flowing bottom-hole pressure (~1000 psig). This indicates strong natural flow ability at the start.

Decision: Focus on well surveillance to monitor the inevitable decline in performance and proactively plan for intervention.

Mid-Life/Current Condition (Intermediate Values): For an intermediate case, perhaps a rate of approximately 2500 STB/day at a flowing bottom-hole pressure of ~1800 psig, the well is still flowing naturally but performance has degraded.

Decision: This is the critical stage to implement artificial lift. The plot helps select the optimal timing and type of lift (e.g., gas lift, ESP) to lower the VLP curve and increase the production rate back toward the higher end of the IPR.

Late Life (Low Pressure, High Water Cut): The leftmost curves indicate a scenario where production rates drop significantly (e.g., below 1000 STB/day), and eventually, the IPR and VLP may not intersect (not shown), meaning the well dies.

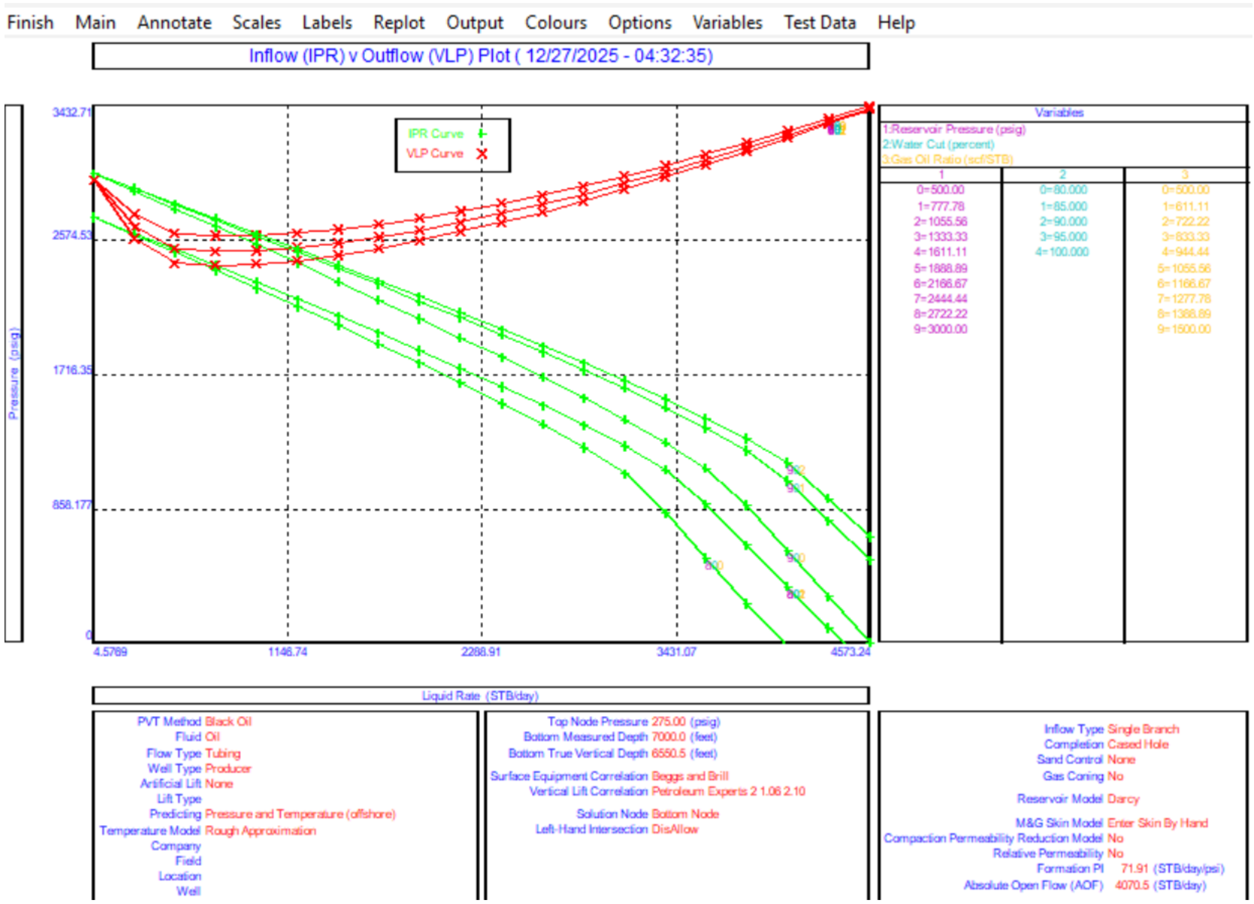


Figure 4.3: IPR vs VLP – Natural flow

Case 2: Gas lifted well

Gas Lift Gas Gravity (0.7 sp. gravity): This value is the specific gravity of the injection gas relative to air. A gravity of 0.7 indicates a lighter-than-air gas (likely a natural gas composed primarily of methane). This property directly influences the density and pressure gradient of the gas phase in the annulus and the gas-liquid mixture in the tubing. Lower gas gravity generally results in better lift efficiency due to a lighter fluid column.

Injection Parameters

This section defines how the gas is supplied to the well.

GLR Injected (0 scf/STB): This field is set to zero because the "Use Injected Gas Rate" option is selected. Gas-liquid ratio (GLR) refers to the volume of gas injected per stock tank barrel of liquid produced.

Injected Gas Rate (0.5 MMscf/day): This is the controlled variable for the simulation or operation. This specific rate (0.5 Million standard cubic feet per day) is an initial or design rate used for performance curve analysis. Varying this rate within the simulation would generate a gas lift performance curve (GLPC) to identify the optimum injection volume that maximizes liquid production without excessive gas slippage, which can reduce efficiency.

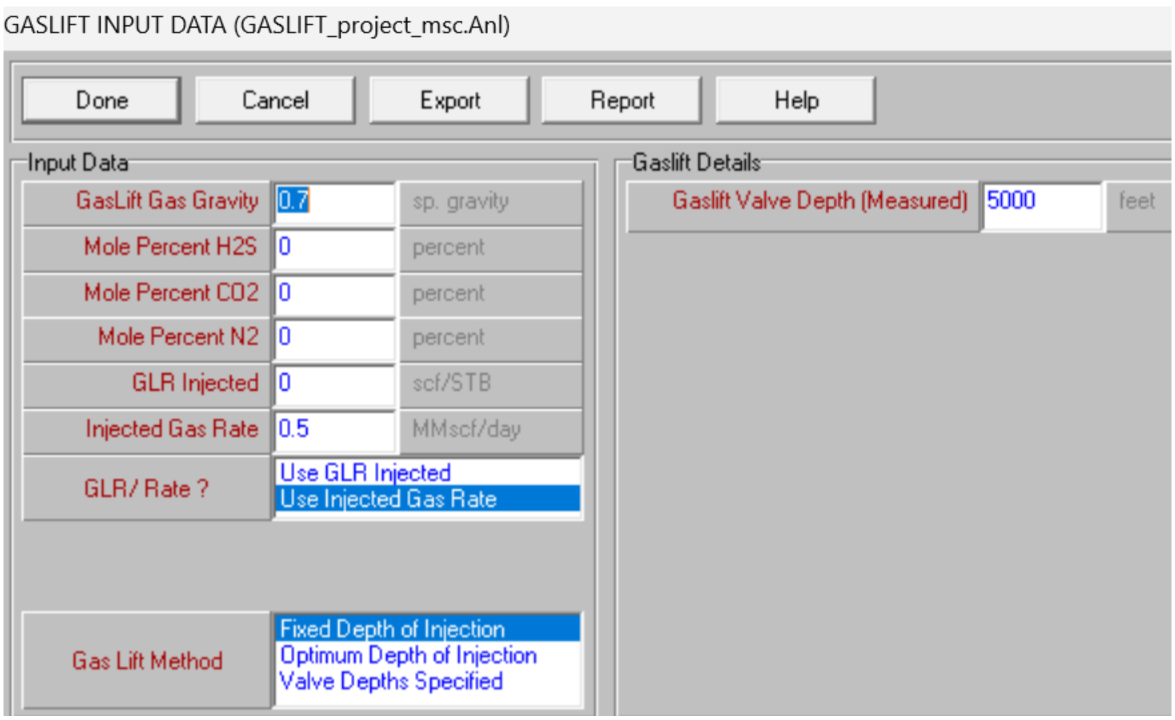


Figure 4.4: Gas input design section

Injection Depth and Method

The depth of gas injection is a critical design parameter, as injecting deeper generally results in greater production rates due to a longer aerated fluid column.

Gaslift Valve Depth (Measured) (5000 feet): This indicates the depth at which the operating gas lift valve is set or the intended point of gas entry. This depth is limited by the available surface injection pressure and well geometry.

Gas Lift Method: The selection for "Use Injected Gas Rate" and the method options "Fixed Depth of Injection," "Optimum Depth of Injection," and "Valve Depths Specified" indicate that any option can be selected o either simulate performance at a single fixed depth or run an optimization routine to determine the ideal depth to maximize flow. The specific choices here guide the software's calculation methodology.

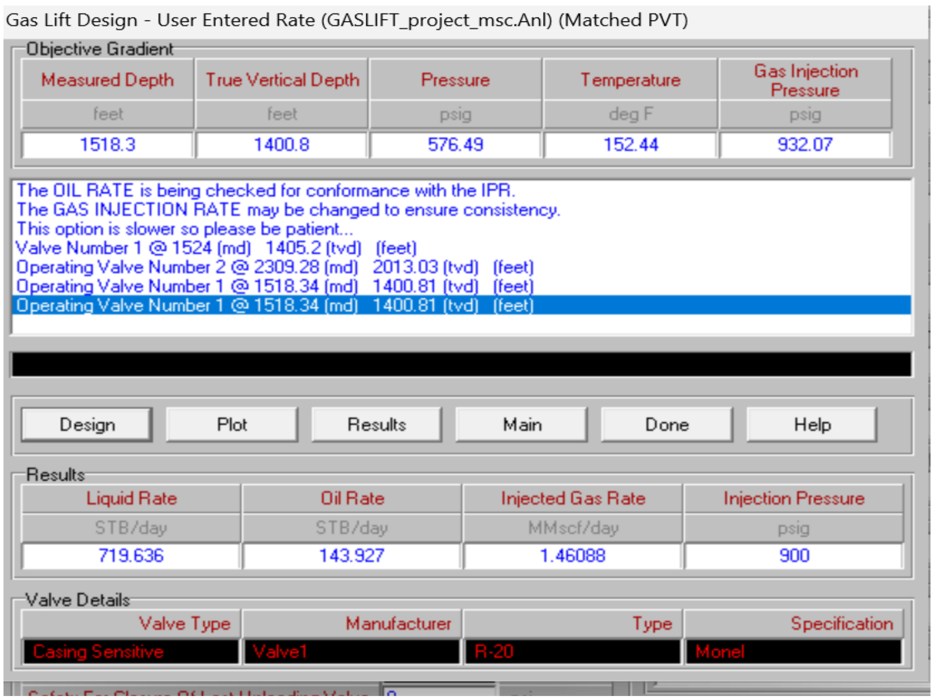


Figure 4.5: Gas lift design solution details.

The software is actively checking the calculated flow conditions against the Inflow Performance Relationship (IPR), which describes the reservoir's ability to flow fluid into the wellbore. The message "The OIL RATE is being checked for conformance with the IPR" confirms that an integrated production model is being used, linking reservoir performance with wellbore hydraulics. This ensures the predicted production rate is physically achievable given the current reservoir characteristics. The process is computationally intensive.

Operational Data and Valve Status

The well is directional, as indicated by the difference between the Measured Depth (MD) and True Vertical Depth (TVD). The current operational depth has a measured depth of 1518.3 ft and a true vertical depth of 1400.8 ft.

Pressure at this depth is 576.49 psig.

Temperature is 152.44 deg F.

Gas Injection Pressure required at this point is 932.07 psig.

The log shows multiple gas lift valves were likely designed for unloading the well, but the simulation has settled on one "Operating Valve" at a shallow depth of 1518.34 ft (MD). The purpose of gas lift is to inject compressed gas through the annulus and into the tubing via an operating valve, which reduces the hydrostatic pressure of the fluid column and helps lift the oil to the surface.

Production Results

The simulation results provide the current, stable production rates under the specified operating conditions:

Parameter	Value	Units	Description
Liquid Rate	719.636	STB/day	Total well production rate (oil + water).
Oil Rate	143.927	STB/day	Net stock tank oil production rate.
Injected Gas Rate	1.46088	MMScf/day	
Injection Pressure	900	psig	

The low oil rate compared to the total liquid rate suggests a high water cut or low Gas-Oil Ratio (GOR) scenario, which often necessitates artificial lift. The gas injection pressure of 900 psig is the required surface pressure to achieve the injected gas rate of 1.46 MMscf/day at the specified operating valve depth.

Valve and Equipment Specifications

The operating valve is specified as a Casing Sensitive Valve 1, Manufacturer R-20, Type Monel. This information is crucial for material selection and design:

Casing Sensitive: Indicates that the valve's operation is influenced by the pressure in the casing annulus, where the injection gas is supplied.

R-20: A standard model of gas lift valve from the manufacturer Camco, used in continuous flow operations.

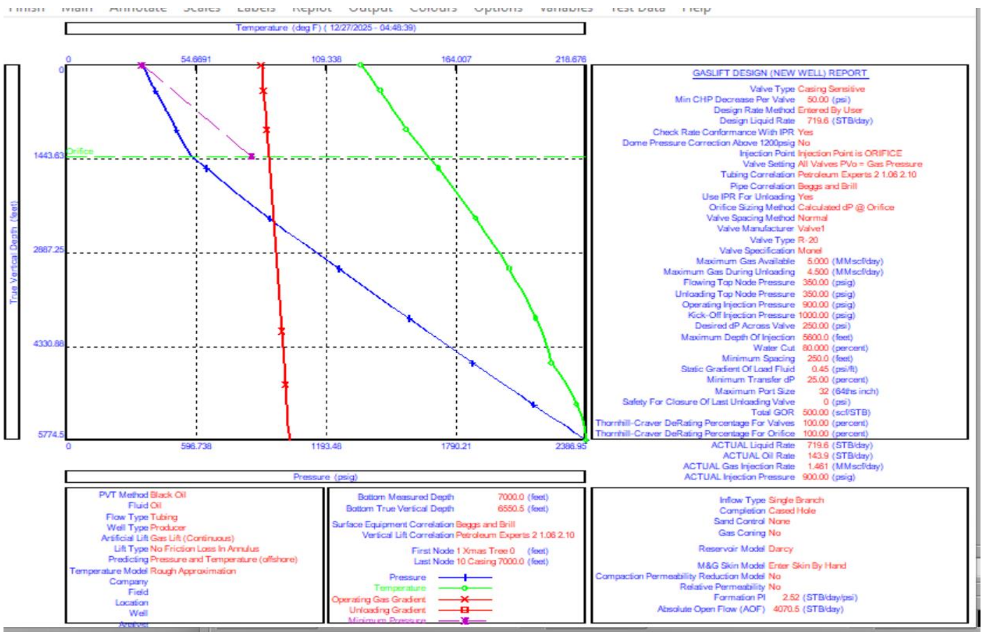


Figure 4.6: IPR vs VLP – Gas lifted well

This design is stable and functional for producing the specified rates. The system is designed for a new well with a target liquid production rate of 719 STB/day. The design uses casing-sensitive valves and specifies an R-20 Monel valve type from the manufacturer Camco. Crucial design limits are set, including a maximum depth of 10,000 ft and a safety factor for the operating valve setting. The maximum available gas rate is 5 MMscf/day, but the actual injected rate for this solution is 1.461 MMscf/day. The injection pressure required to achieve this depth is 900 psig.

Operating Principles and Gradients

The plot on the left of figure 4.6 visually represents the pressure and temperature gradients within the wellbore. The Inflow Performance Relationship (IPR) and Vertical Lift Performance

(VLP) curves intersect at the current operating point, which confirms the calculated production rate is in conformance with the reservoir's ability to flow fluid. The green line in the plot, representing the flowing gradient after gas injection, is significantly less steep than the natural flow gradient (implied by the original IPR slope), demonstrating the effectiveness of the gas lift in reducing the fluid density and bottomhole pressure (BHP).

Actual Production Results

The simulation results at the bottom right confirm the actual stabilized production rates:

Actual Oil Rate: 143.9 STB/day

Actual Gas Injection Rate: 1.461 MMscf/day

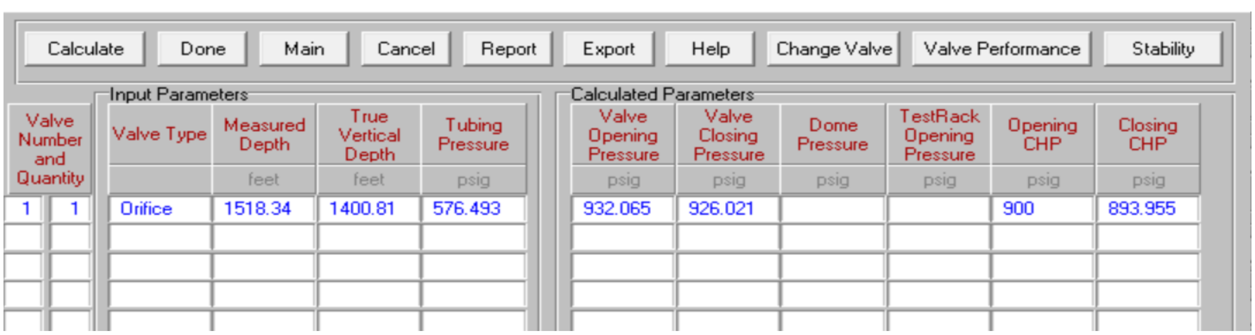
Actual Injection Pressure: 900.00 psig

The "well type" is set to "Predicting Pressure and Temperature (offshore)", indicating the use of a predictive thermal and hydraulic model for a deepwater environment.

Fluid Properties and Well Status

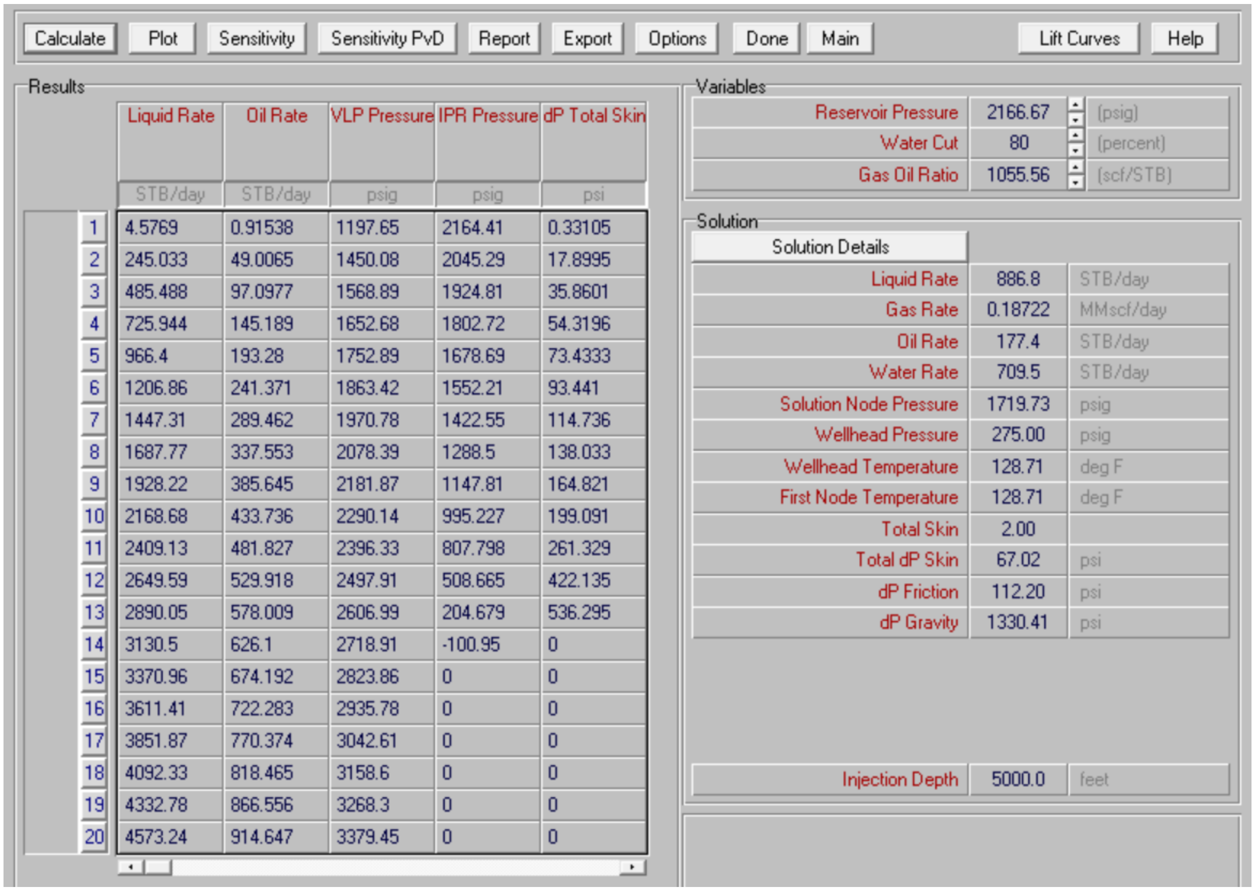
The PVT (Pressure-Volume-Temperature) method selected is for "Black Oil," a standard model for typical crude oil systems. The fluid is characterized by an oil gravity of 21 API. The absence of H_2S, CO_2, or N_2 contaminants in the injection gas simplifies corrosion management and material selection for surface and downhole equipment. The well has a high water cut (80.0%), which is a common reason for employing artificial lift as the well's natural energy declines.

The current gas lift design appears to be effective in sustaining production under these conditions.



Valve Number and Quantity		Valve Type	Measured Depth	True Vertical Depth	Tubing Pressure	Valve Opening Pressure	Valve Closing Pressure	Dome Pressure	TestRack Opening Pressure	Opening CHP	Closing CHP
			feet	feet	psig	psig	psig	psig	psig	psig	psig
1	1	Orifice	1518.34	1400.81	576.493	932.065	926.021			900	893.955

Figure 4.7: Optimum gas lift design parameters



	Liquid Rate (STB/day)	Oil Rate (STB/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)
1	4.5769	0.91538	1197.65	2164.41	0.33105
2	245.033	49.0065	1450.08	2045.29	17.8995
3	485.488	97.0977	1568.89	1924.81	35.8601
4	725.944	145.189	1652.68	1802.72	54.3196
5	966.4	193.28	1752.89	1678.69	73.4333
6	1206.86	241.371	1863.42	1552.21	93.441
7	1447.31	289.462	1970.78	1422.55	114.736
8	1687.77	337.553	2078.39	1288.5	138.033
9	1928.22	385.645	2181.87	1147.81	164.821
10	2168.68	433.736	2290.14	995.227	199.091
11	2409.13	481.827	2396.33	807.798	261.329
12	2649.59	529.918	2497.91	508.665	422.135
13	2890.05	578.009	2606.99	204.679	536.295
14	3130.5	626.1	2718.91	-100.95	0
15	3370.96	674.192	2823.86	0	0
16	3611.41	722.283	2935.78	0	0
17	3851.87	770.374	3042.61	0	0
18	4092.33	818.465	3158.6	0	0
19	4332.78	866.556	3268.3	0	0
20	4573.24	914.647	3379.45	0	0

Variables		
Reservoir Pressure	2166.67	(psig)
Water Cut	80	(percent)
Gas Oil Ratio	1055.56	(scf/STB)

Solution Details		
Liquid Rate	886.8	STB/day
Gas Rate	0.18722	MMscf/day
Oil Rate	177.4	STB/day
Water Rate	709.5	STB/day
Solution Node Pressure	1719.73	psig
Wellhead Pressure	275.00	psig
Wellhead Temperature	128.71	deg F
First Node Temperature	128.71	deg F
Total Skin	2.00	
Total dP Skin	67.02	psi
dP Friction	112.20	psi
dP Gravity	1330.41	psi
Injection Depth	5000.0	feet

Figure 4.8: Solution node details gas lifted well

The simulation provides the stabilized operating conditions where the reservoir's Inflow Performance Relationship (IPR) matches the wellbore's Vertical Lift Performance (VLP). This intersection occurs at the following key parameters:

The significant difference between the reservoir pressure and the solution node pressure (bottom-hole flowing pressure) confirms the system's effectiveness in maintaining a sufficient drawdown across the reservoir sand face, which is the primary mechanism for boosting production in a gas lift system. The resulting oil rate of 177.4 STB/day indicates a successful production enhancement scenario compared to natural flowing conditions (which produced zero oil). The high water cut of 80% (specified as an input variable) is a typical scenario requiring artificial lift, as the heavy water column significantly increases the hydrostatic pressure gradient.

Pressure Loss Analysis

The total pressure drop in the system is broken down into its constituent parts:

Pressure Loss Component	Value	Units
dP Friction	112.20	psi
dP Gravity	1330.41	psi
Total dP Skin	67.02	psi

The gravity component is by far the dominant pressure loss (1330.41 psi). The purpose of gas lift is precisely to minimize this gravity pressure drop by aerating the fluid column, thus reducing the overall fluid density within the production tubing. The relatively low frictional pressure drop (112.20 psi) is a positive finding, as excessive friction can counteract the benefits of reduced hydrostatic pressure, and can become a problem if too much gas is injected beyond the optimum rate.

Operational and Design Parameters

The system is designed for a target injection depth of 5000.0 feet. Injecting as deep as possible is generally more efficient in reducing the fluid column density above the injection point, provided sufficient injection pressure is available. The total skin factor is 2.00, which suggests some formation damage or near-wellbore restriction that affects the inflow performance but is being managed by the effective drawdown created by the gas lift system.

This design provides a clear operating point for the well.

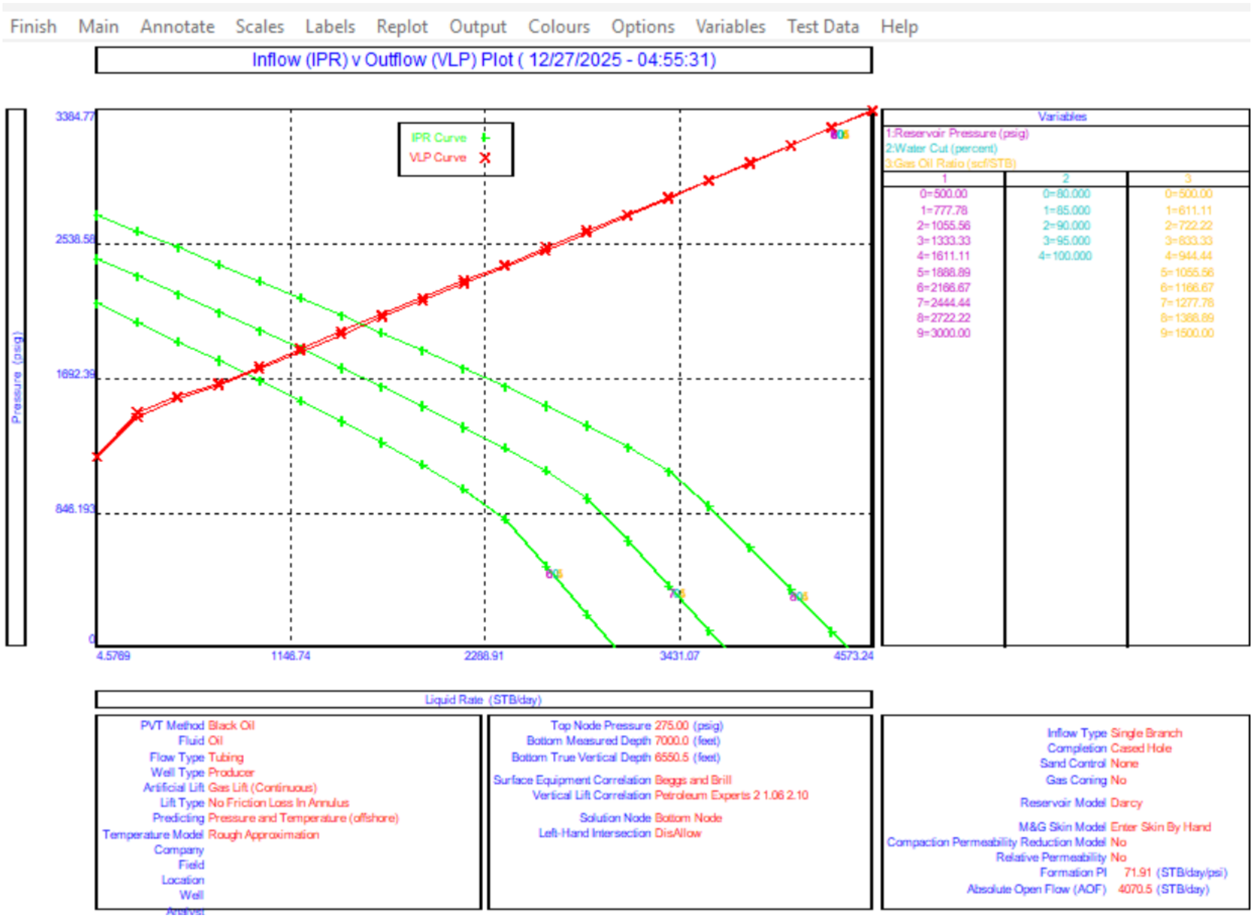


Figure 4.9: IPR vs VLP – Natural flow gas lifted well

The core technical principle observed is the reduction of the flowing fluid's hydrostatic pressure gradient. By injecting compressed gas into the production tubing at a specific depth, the overall density of the gas-liquid mixture in the tubing is decreased. This process effectively "lightens" the fluid column, which lowers the BHP (increases the drawdown on the reservoir) and enables the reservoir to produce at a higher liquid rate than it would naturally.

Key Operational and Design Parameters

The input data in the lower panels provides critical context for the simulation:

Bottom Measured Depth (MD): The well reaches a total depth of 7000.0 (feet).

Bottom True Vertical Depth (TVD): The vertical depth is 6560.5 (feet), indicating a deviated well path.

Artificial Lift Method: The selection is Gas Lift (Continuous), which uses a steady stream of injected gas.

Vertical Lift Correlation: The software uses the "Petroleum Experts 21.062.10" correlation (Beggs and Brill, as stated for surface equipment), a validated method for modeling multiphase flow in tubing.

Formation PI (Productivity Index): The PI is 7.91 (STB/day/psi), which is the reservoir's inherent measure of flow capacity.

Absolute Open Flow (AOF): The AOF is 4070.5 (STB/day), representing the theoretical maximum flow rate if the BHP was zero. The actual production rate will be a fraction of this.

Interpretation of the Plot

The plot 4.9 visually confirms that at the intersection point, a specific pressure and liquid rate are achieved. The divergence of the base VLP and the gas-lifted VLP at shallower depths (higher pressures) illustrates the significant impact of the injected gas on the pressure gradient, fundamentally changing the hydraulics of the production string to meet the required lift to surface. The design parameters ensure that the system can operate within the physical constraints of the wellbore and surface facilities.

Case 3: ESP lifted well

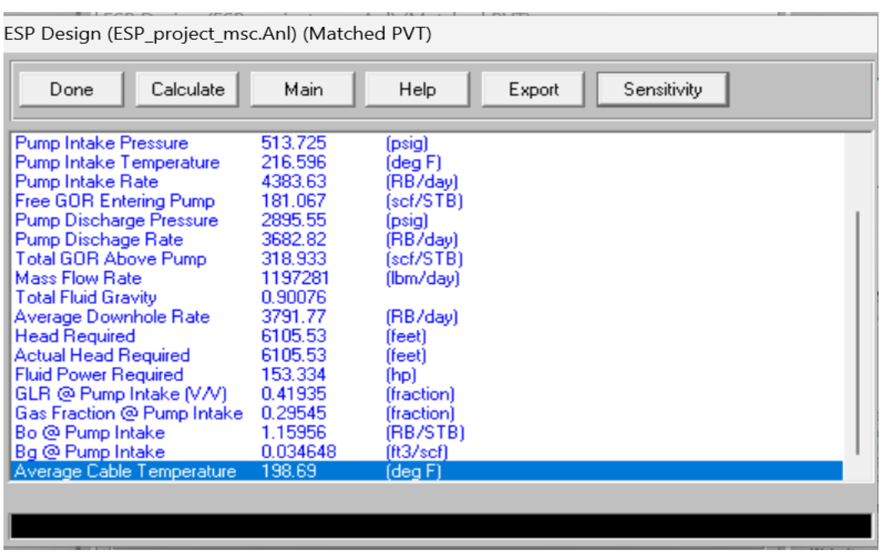


Figure 4.10: ESP Design results

The pump is operating with specific intake and discharge conditions determined by the system's nodal analysis, where reservoir inflow matches the wellbore outflow performance.

Pump Intake Pressure (PIP): The PIP is 513.725 psig. This is a critical parameter that determines the available pressure head at the pump suction and whether free gas will enter the pump. A sufficient PIP is necessary to prevent cavitation and gas locking, which can severely damage the ESP.

Pump Intake Rate: The pump is handling a total fluid rate of 4383.63 RB/day (reservoir barrels per day) at the pump depth.

Pump Discharge Pressure: The fluid pressure is significantly boosted to 2895.55 psig at the pump discharge, which is the pressure required to lift the fluid column to the surface facilities.

Multiphase Flow and Gas Handling

The data indicates the presence of gas within the fluid column, which is a key consideration for ESP applications, as standard centrifugal pumps are not ideal for high gas fractions.

Free GOR Entering Pump: The gas-oil ratio (GOR) of free gas entering the pump is 181.067 scf/STB (standard cubic feet per stock tank barrel).

Gas Fraction @ Pump Intake: The gas fraction (volume/volume) at the pump intake is 0.29545 (or approximately 29.5%). Handling this amount of free gas requires either a specialized gas handler device integrated into the ESP string or a design that avoids gas breakout at the pump intake pressure.

Total GOR Above Pump: The GOR above the pump increases to 318.933 scf/STB, suggesting further gas liberation from the liquid phase as pressure decreases up the tubing.

Pump Performance Metrics

The simulation quantifies the energy requirements for the lift operation:

Head Required: The ESP must generate 6105.53 feet of head to overcome the hydrostatic pressure of the fluid column and surface pressure.

Fluid Power Required: The actual power imparted to the fluid is 153.334 hp. This is the hydraulic power output of the pump and is used in conjunction with the pump efficiency to select the appropriate motor size.

These data represents a functional ESP design operating with a notable gas fraction at the pump intake, a scenario that requires careful pump and motor selection to ensure longevity and stable operation.

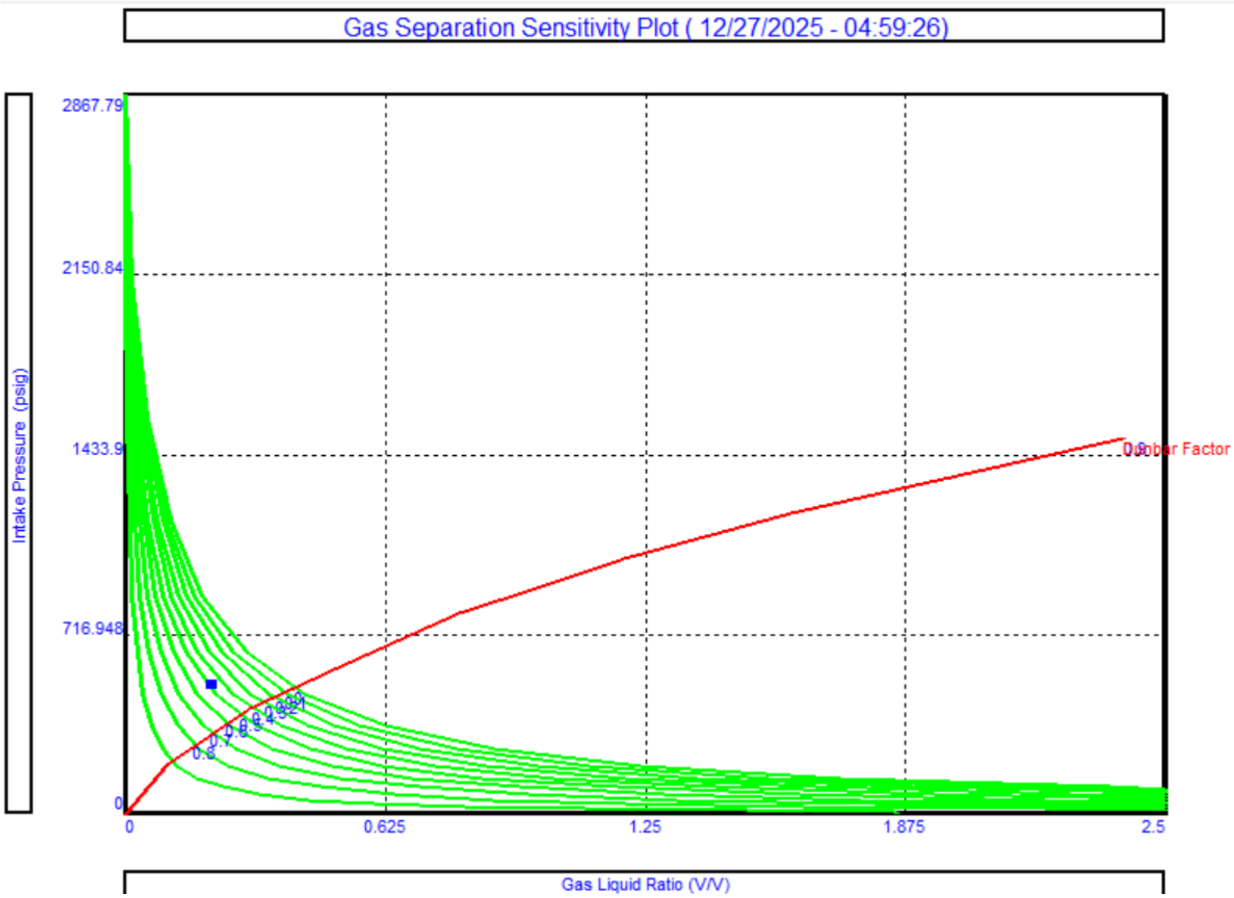


Figure 4.11: Dunbar plot

The plot 4.11 demonstrates the complex pressure-volume-temperature (PVT) behavior of a hydrocarbon fluid system. The family of green curves represents varying fluid conditions. The key technical insight is the red line, which signifies the bubble point pressure locus. The bubble point is the pressure at which the first bubble of gas comes out of solution from the liquid phase as the pressure is decreased at a constant temperature.

Operating Region: To the left of the red curve, the fluid is predominantly liquid phase with gas in solution. To the right of the red curve, the fluid is a two-phase mixture (free gas and liquid).

Pressure-GLR Relationship: The curves show that as the gas-liquid ratio (GLR) increases, the required intake pressure to keep the gas in solution generally increases, up to a point where the bubble point is reached. This relationship is critical for designing flow assurance strategies and selecting appropriate artificial lift methods.

Relevance to Gas Lift Principles

While this is a fluid properties plot, its data are fundamental inputs for gas lift design simulation software. Gas lift operates by injecting external gas to reduce the hydrostatic pressure of the fluid column and increase the flowing bottomhole pressure (BHP). The principles demonstrated in this plot relate to:

Avoiding Gas Breakout: In gas lift systems, controlling the pressure profile downhole is crucial. This plot highlights the pressures at which free gas will form. Managing the injection depth and pressure to operate the system optimally relative to the bubble point ensures efficient lifting and prevents operational issues like gas locking or pump cavitation (if an ESP were used instead).

Density Reduction: The ability of gas lift to decrease the fluid column density is intrinsically linked to the phase behavior shown here. The injection of gas moves the fluid mixture into the two-phase region (right of the red line), where the bulk density is significantly lower, allowing the fluid to be lifted to the surface.

Sensitivity Analysis Interpretation

The numerous green curves indicate a sensitivity analysis for a specific variable (e.g., temperature, water cut, or different fluid correlations). The data suggests that slight changes in operating conditions can significantly shift the phase envelope, impacting the required injection pressures and overall system stability.

The figure is a crucial visual aid for understanding the phase boundaries of the produced fluid. It informs the engineering decisions necessary for optimal artificial lift design, including ensuring the system operates efficiently within the desired single or two-phase flow regimes.

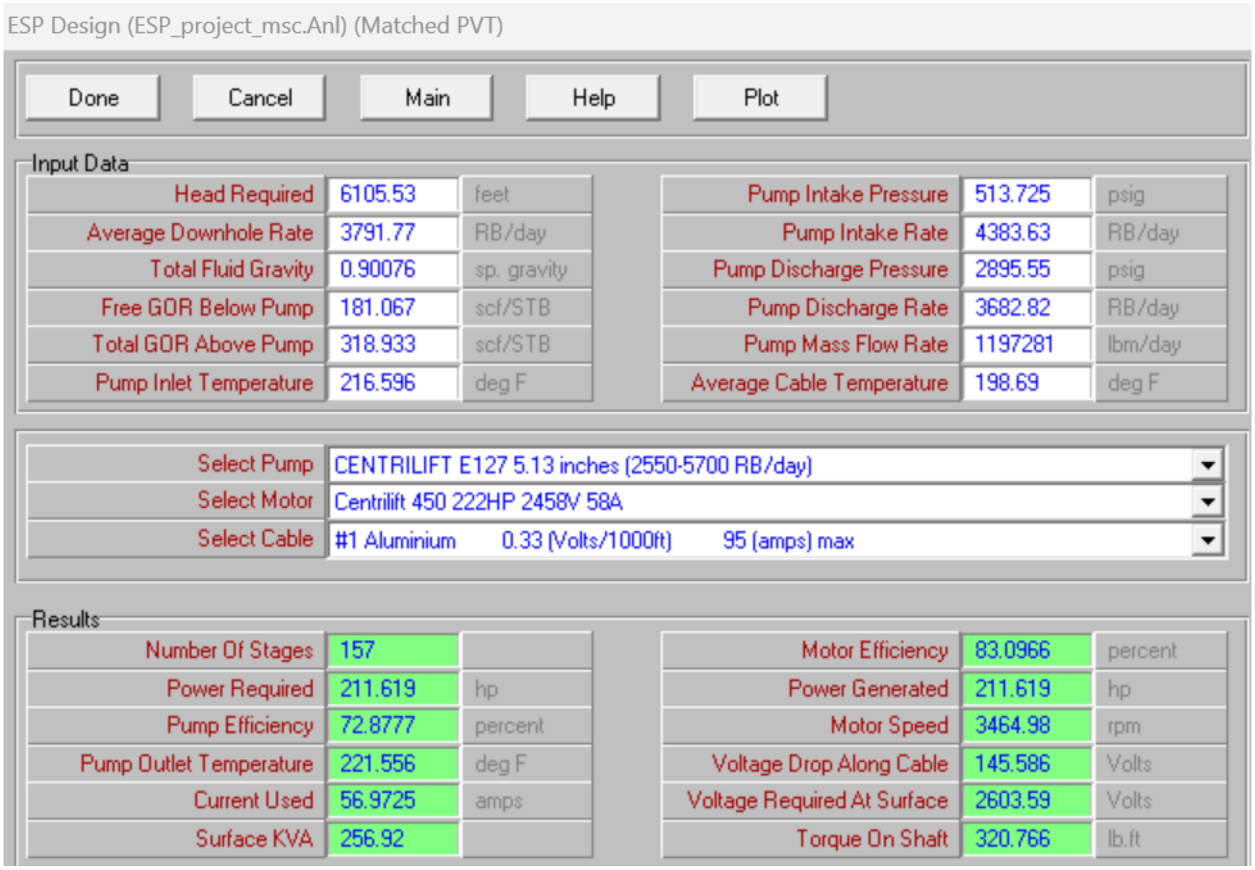


Figure 4.12: ESP pump selection and design

Pump and Motor Performance Metrics

The simulation quantifies the energy requirements and performance of the selected equipment:

Head Required: The ESP must generate 6105.53 feet of head to overcome the hydrostatic pressure of the fluid column and surface pressure.

Power Required: The pump requires 211.619 hp (brake horsepower) from the motor to lift the fluid. This corresponds to a fluid power output of approximately 153 hp (derived from total liquid rate and head).

Pump Efficiency: The pump is operating at an efficiency of 72.8777 percent, which is within an optimal range for these types of pumps.

Motor Efficiency: The electrical motor is operating at 83.0966 percent efficiency.

Current Used: The system draws 56.9725 amps to operate effectively.

Voltage Required At Surface: The system requires 2603.59 Volts at the surface to account for voltage drop along the cable and deliver the necessary power downhole.

Fluid and Wellbore Conditions

The data provides insight into the downhole environment:

Pump Intake Pressure (PIP): The PIP is 513.725 psig. Maintaining sufficient pressure at the intake is crucial to prevent the formation of excessive free gas (cavitation) and ensure stable pump operation.

Free GOR Below Pump: The presence of 181.067 scf/STB of free gas at the pump intake indicates that a gas handling device is likely necessary for reliable operation, as standard centrifugal pumps struggle with high gas fractions.

Average Downhole Rate: The ESP is designed for an average downhole production rate of 3791.77 RB/day, which is a high flow rate typical for ESP applications.

In conclusion, the data represents a high-efficiency ESP system design operating successfully within specified parameters.

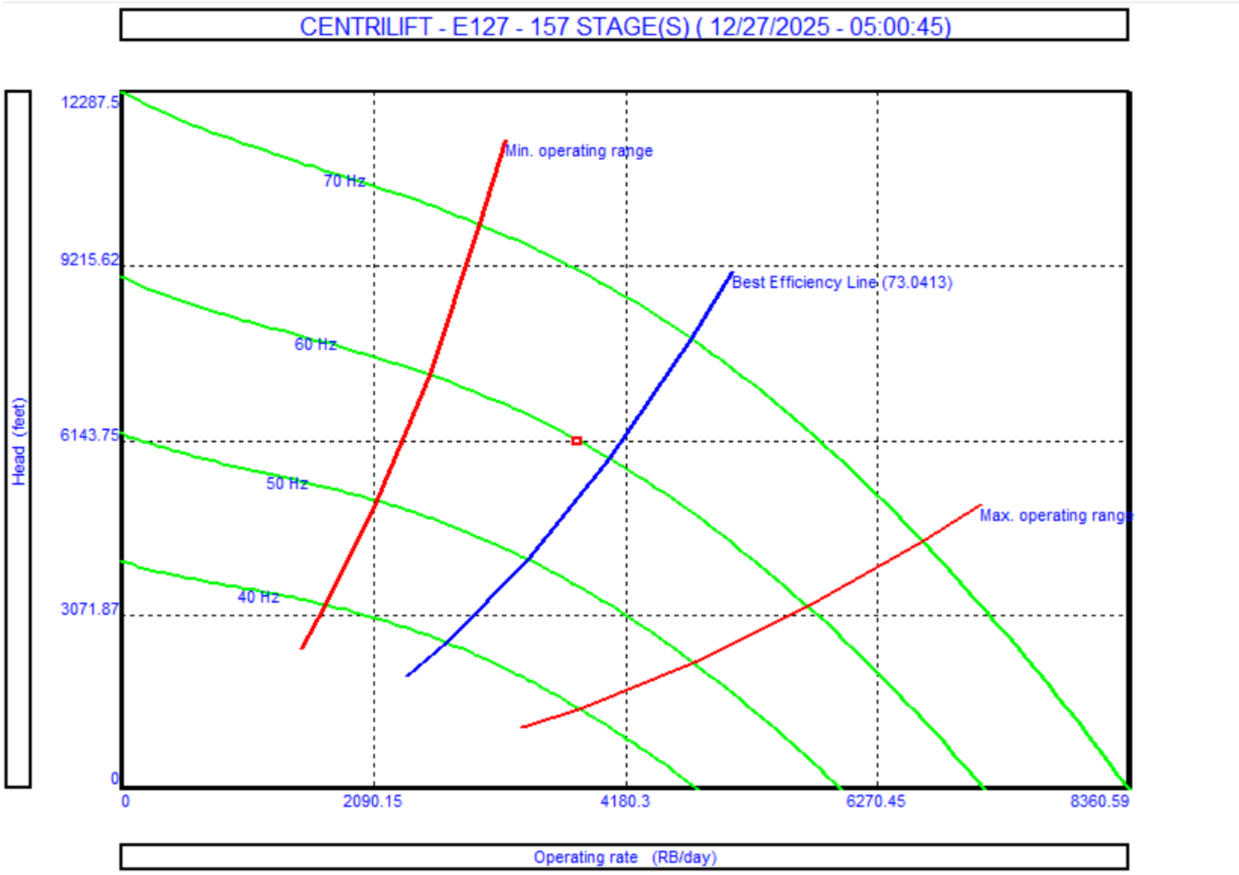


Figure 4.13: ESP pump Efficiency

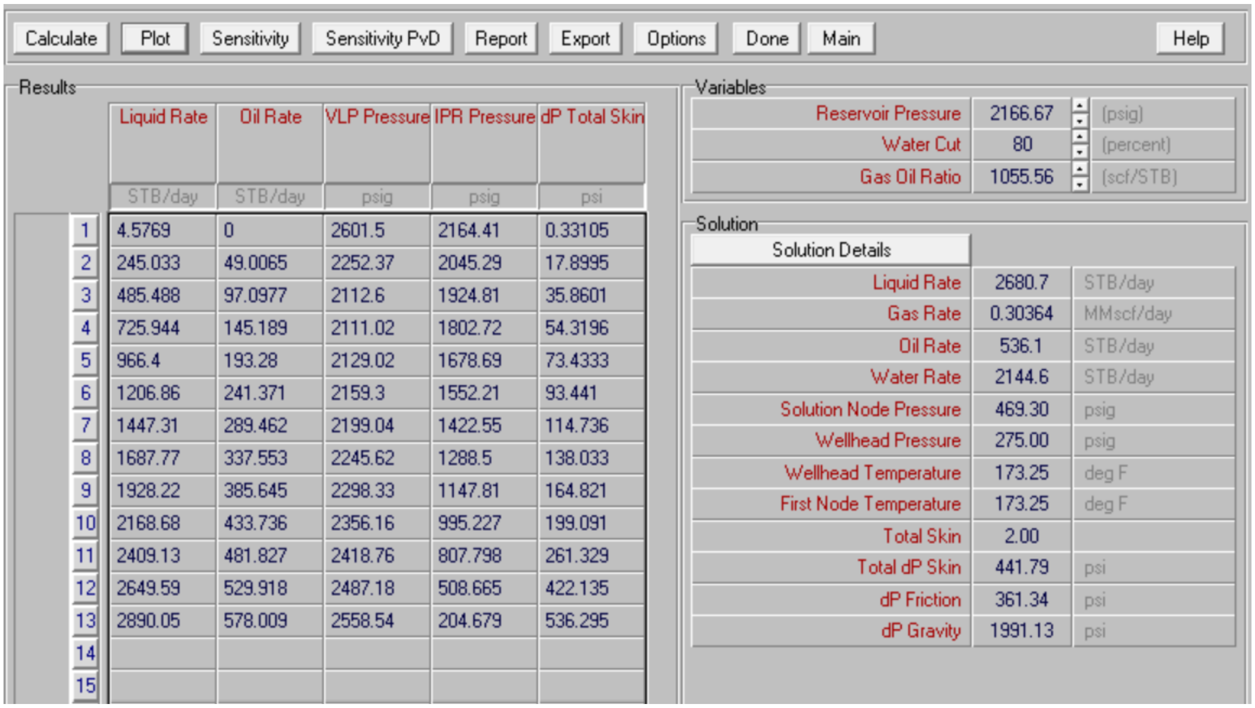
Pump Performance Data: The figure 4.13 plots the relationship between the operating rate (production rate in barrels per day, RB/day) on the x-axis and the total head (in feet, ft) generated by the pump on the y-axis.

Variable Frequency Drives (VFDs): Multiple curves are shown for different operating frequencies (50 Hz, 60 Hz, 70 Hz), demonstrating how a VFD can adjust pump performance to match changing well conditions and optimize production.

Operating Range and Efficiency:

A “Best Efficiency Line” indicates the flow rates at which the pump operates most efficiently.

“Max operating range” lines define the recommended operational limits to ensure the pump’s longevity and avoid issues like cavitation or excessive wear.



	Liquid Rate	Oil Rate	VLP Pressure	IPR Pressure	dP Total Skin
	STB/day	STB/day	psig	psig	psi
1	4.5769	0	2601.5	2164.41	0.33105
2	245.033	49.0065	2252.37	2045.29	17.8995
3	485.488	97.0977	2112.6	1924.81	35.8601
4	725.944	145.189	2111.02	1802.72	54.3196
5	966.4	193.28	2129.02	1678.69	73.4333
6	1206.86	241.371	2159.3	1552.21	93.441
7	1447.31	289.462	2199.04	1422.55	114.736
8	1687.77	337.553	2245.62	1288.5	138.033
9	1928.22	385.645	2298.33	1147.81	164.821
10	2168.68	433.736	2356.16	995.227	199.091
11	2409.13	481.827	2418.76	807.798	261.329
12	2649.59	529.918	2487.18	508.665	422.135
13	2890.05	578.009	2558.54	204.679	536.295
14					
15					

Variables		
Reservoir Pressure	2166.67	(psig)
Water Cut	80	(percent)
Gas Oil Ratio	1055.56	(scf/STB)

Solution Details		
Liquid Rate	2680.7	STB/day
Gas Rate	0.30364	MMscf/day
Oil Rate	536.1	STB/day
Water Rate	2144.6	STB/day
Solution Node Pressure	469.30	psig
Wellhead Pressure	275.00	psig
Wellhead Temperature	173.25	deg F
First Node Temperature	173.25	deg F
Total Skin	2.00	
Total dP Skin	441.79	psi
dP Friction	361.34	psi
dP Gravity	1991.13	psi

Figure 4.14: ESP sensititvity analysis

A sensitivity analysis was performed using the provided software to understand the performance envelope of the ESP system under varying operating conditions. The primary variable investigated was the Liquid Rate, ranging from approximately 245 STB/D to 2890 STB/D.

Key results and observations are as follows: Pressure Profile: As the liquid rate increases, the wellbore flowing pressures exhibit a consistent trend. The Solution Node Pressure and PR (Pump Intake) Pressure generally decrease, while the Pump Discharge Pressure (VLP Pressure) increases.

Pressure Drop Across Skin: The total pressure drop due to skin (\(\Delta P_{TotalSkin}\)) increases significantly with higher flow rates. It starts at a minimal value (0.33105 psi) at the lowest rate and escalates to over 536 psi at the maximum rate, indicating a strong dependency of pressure losses on flow velocity. Pump Performance:

The difference between the VLP Pressure and the PR Pressure (pump head) increases with flow rate, demonstrating the pump's response to the varying intake conditions. System Variables: The analysis was conducted with constant system parameters, including a Reservoir Pressure of 2166.67 psi, a Water Cut of 80%, and a Total Skin of 200.

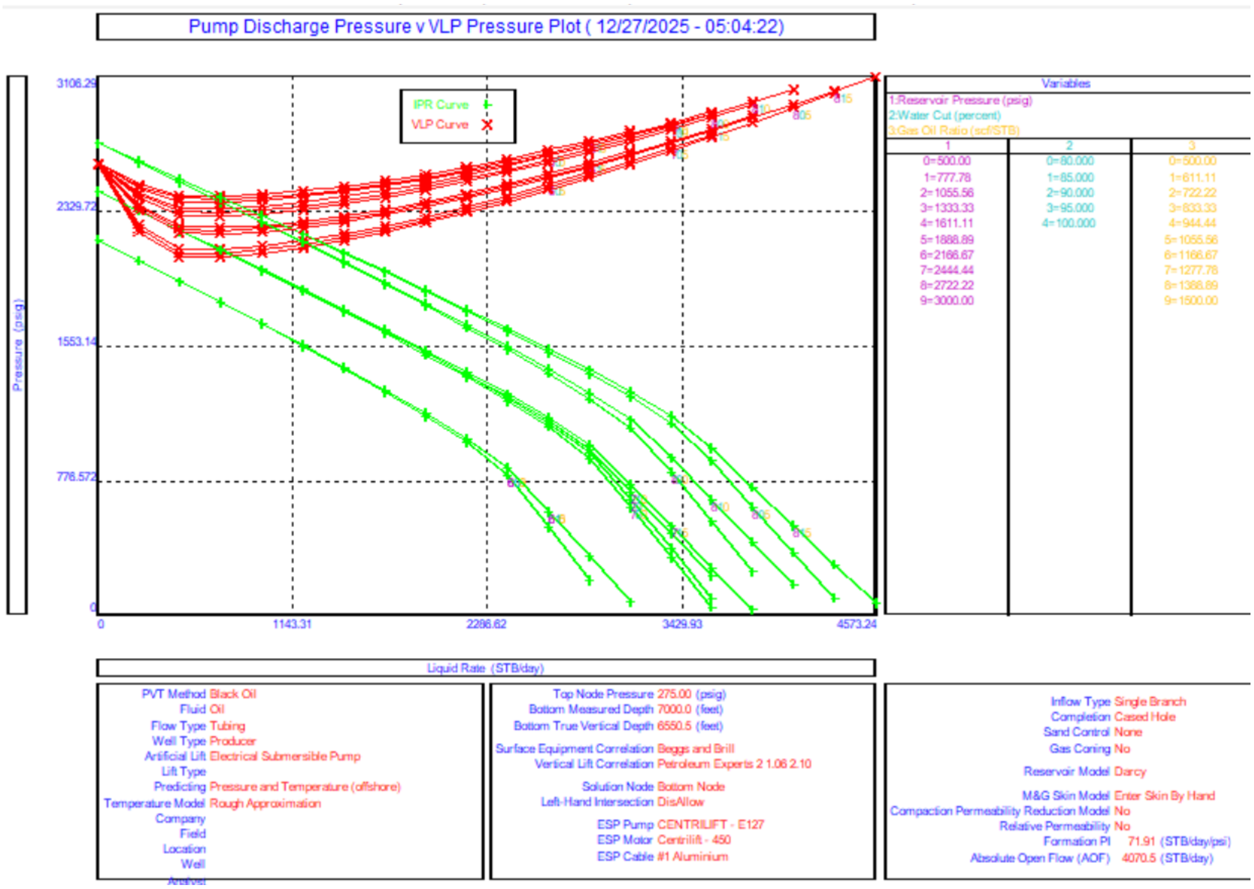


Figure 4.15: ESP IPR vs VLP

The image displays a “Pump Discharge Pressure v VLP Pressure Plot,” which is a visual representation of a Vertical Lift Performance (VLP) versus Inflow Performance Relationship (IPR) sensitivity analysis for an Electric Submersible Pump (ESP) system. This type of analysis is typically used in petroleum engineering to evaluate well performance under various operating conditions.

The plot shows two main sets of curves:

Red Curves: These represent the pump discharge pressure (likely corresponding to the VLP). Multiple red curves indicate a sensitivity analysis where one or more parameters were varied (e.g., fluid properties, pump speed, or wellhead pressure).

Green Curves: These represent the required intake pressure (likely corresponding to the IPR). Similar to the red curves, the multiple green curves show how the required pressure changes with variations in specific parameters (e.g., reservoir pressure, water cut, or permeability).

The intersection points of the red and green curves for each scenario represent the potential operating points of the well. The accompanying tables provide the specific parameters that were varied for the analysis, including:

Well Type: Oil Producer

Flow Type: Multiphase Flow

Pump Type: Electric Submersible Pump

Other parameters: Including specific details about the reservoir, fluid properties, and equipment specifications.

Label	ESP Lifted Well	Prediction method	Pressure and temperature
Name		Optimisation method	Production

	Gaslift available	Oil Rate	Gas Rate	Water Rate	Liquid Rate	Gas Lift Injection Rate	Revenue
	MMscf/day	STB/day	MMscf/day	STB/day	STB/day	MMscf/day	MMUS$/da
1	5.000	802.2	0.401	3208.7	4010.9	0.000	0.00
2	1.500	802.2	0.401	3208.7	4010.9	0.000	0.00
3	2.000	802.2	0.401	3208.7	4010.9	0.000	0.00
4	2.500	802.2	0.401	3208.7	4010.9	0.000	0.00
5	3.000	802.2	0.401	3208.7	4010.9	0.000	0.00
6	3.500	802.2	0.401	3208.7	4010.9	0.000	0.00
7	4.000	802.2	0.401	3208.7	4010.9	0.000	0.00

Gap simulation results

Figure 4.16: ESP Lifted well results

The figure 4.16 shows the prediction summary for the 3 modelled wells in the GAP software.

The oil rate, water and gas rate from each of natural flow, ESP and Gas lifted well are presented.

A total of 802b/d of oil was observed for the ESP lifted well, while the as lifted well recorded an oil rate of 175b/d with a gas lift injection rate of 1.5MMscf/d. The natural flow well produced no oil due to insufficient reservoir energy. ESP generate a higher drawdown by reducing the bottom hole pressure to low values allowing flow of oil from the well to the surface. The high water cut or declining pressure reduces the efficacy of the gas lift system, while the natural flowing well did not produce oil.

Conclusions

The reservoir under study is strongly supported by an active aquifer; aquifer influx explains the sustained pressure but also the persistently high water cut during late

History matching (1987–2004 data) produced a validated MBAL/PROSPER/GAP model with close agreement between simulated and observed pressures, showing the modelling workflow is reliable for forecasting and prediction

Under current reservoir conditions (high water cut ~80% and declining pressure), the field cannot sustain target vertical lift rates without artificial lift — natural flow is no longer sufficient.

Sensitivity analysis shows reservoir pressure and water cut are the dominant drivers of well deliverability and operating point; a reservoir pressure near ~1700 psig marks an important threshold for needing intervention.

ESPs can deliver higher peak liquid rates and, where power and operating conditions permit, often give a superior NPV compared to gas lift; however gas lift remains preferable where lift gas is abundant and ESP reliability/costs are limiting.

Surface/network constraints and allocation (GAP) materially affect well-level gains — well performance improvements must be evaluated in an integrated reservoir–well–surface framework to be meaningful.

Several conventional reservoir/remediation options (selective shut-off, zonal isolation, perforation changes, choke management, infill or lateral wells) remain important complements to artificial lift for water-cut control.

Contributions to knowledge

Demonstrated and documented a practical, repeatable integrated IPM workflow (MBAL → PROSPER → GAP) for production optimization in a mature, high-water-cut Niger Delta reservoir — showing how reservoir, well and surface models interact for decision making.

Produced a calibrated material-balance/aquifer model with quantified aquifer parameters (porosity, radii, aquifer permeability, encroachment angle, etc.) that explain observed late-life pressure/water behaviour for the case study. This offers a regional, data-backed reference for similar reservoirs.

Conducted comparative nodal and nodal-network analyses for three well archetypes (natural flow, gas lift, ESP) including VLP/IPR matching and sensitivity envelopes — giving operational envelopes and failure/limit conditions for each lift option in high-WC scenarios.

Used sensitivity and solution-node analysis to identify key threshold values (e.g., pressures, water-cut ranges, pump frequency/limits) that inform the timing and sizing of lift equipment in high water-cut heavy oil wells.

Recommendations

Operational / field recommendations

Implement a staged artificial-lift program: pilot ESP on wells where power and solids/temperature conditions are favourable; deploy gas lift where gas is plentiful or ESP access/workover risk is prohibitive. Use the case sensitivity envelopes to size equipment.

Start with pilot wells (1–2) and integrate the results back into the MBAL→PROSPER→GAP models before wider roll-out — this reduces uncertainty and avoids overinvestment.

Aggressive diagnostic program: perform production logging, tracers and (where affordable) repeat 4D/monitoring to confirm water sources (edge vs bottom coning vs channeling) prior to permanent shutoff.

Targeted water-control interventions: where diagnostics show local water entry, use selective mechanical zonal isolation, chemical water-shutoff or re-perforation/sidetracking rather than blanket treatments. Combine these with rate control (choke management) to avoid coning.

Optimize surface network concurrently: before ramping up well rates under artificial lift, ensure separators, compressors and pipelines (GAP constraints) can handle additional liquid/gas; otherwise well gains will be limited by surface bottlenecks.

Economic vetting: run life-cycle NPV sensitivity (oil price, failure rates, workover frequency, produced-water OPEX) for each candidate well to pick the lift method with the best risk-adjusted return.

Monitoring & maintenance

Continuous surveillance and periodic re-history match: schedule periodic history matches and sensitivity re-runs as new production/pressure data arrives — this keeps the model valid and informs timing of next interventions.

Condition monitoring for ESPs: if ESPs are selected, include gas handlers/VSD and a monitoring program for gas locking, solids and temperature to minimise unplanned workovers.

Run full 3D reservoir simulations for the field (where data permits) to complement tank/MBAL analyses; this helps evaluate EOR strategies, heterogeneity impacts and infill placement more rigorously.

Evaluate conformance/EOR pilots (polymer, surfactant, WAG or CO_2) as a mid-to-long term option for reservoirs with substantial unswept oil; run small pilots to quantify incremental recovery before scale-up.

REFERENCES

- Ahmad, N.; Al-Shabibi, H.; Malik, S. Comprehensive Diagnostic andWater Shut-o_ in Open and Cased Hole Carbonate Horizontal Wells. Presented at the Abu Dhabi International Petroleum Exhibition and conference, Abu Dhabi, UAE, 11–12 November 2012.
- Beauregard, E., and Ferguson, P.L., 1982, "Introduction to Plunger Lift: Applications, Advantages and Limitations," paper SPE 10882, Rocky Mountain Regional Meeting of the SPE, Billings, MT, May 19-21.
- Beattle, D.R. and Roberts, B.E., 1996, "Water Coning in Naturally Fractured Gas Reservoirs," Paper SPE 35643, Gas Technology Conference, Calgary, Alberta, Canada, 28 April – 1 May.
- Beeson, C.M., Knox, D.G., and Stoddard, J.H., 1958, "Short-Cut Design Calculations and Field Applications of the Plunger Lift Method of Oil Production," The Petroleum Engineer, (June-Oct. 1958).
- Bill Bailey et al: "Water control," Oilfield review, Springer, Texas Houston, USA, 2000.
- Bournazel, C., and Jeanson, B., "Fast Water Coning Evaluation," SPE Paper 3628 Presented at the SPE 46th Annual Fall Meeting, New Orleans, Oct. 3–6, 1971.
- Campbell, S., Ramachandran, S., and Bartrip, K., 2001, "Corrosion Inhibition/Foamer Combination Treatment to Enhance Gas Production," paper SPE 67325, Production and Operations Symposium, Oklahoma City, OK, March 24-27.
- Calhoun, John, Fundamentals of Reservoir Engineering. Norman, OK: The University of Oklahoma Press, 1960.
- Chaney, P. E. et al., "How to Perforate Your Well to Prevent Water and Gas Coning," OGJ, May 1956, p. 108.
- Chaperon, I., 1986, "Theoretical Study of Coning toward Horizontal and Vertical Wells in Anisotropic Formations: Subcritical and Critical Rates," paper SPE 15377, SPE Annual Technical Conference and Exhibition, New Orleans, Oct. 5-8.
- Chierici, G. L., Ciucci, G. M., and Pizzi, G., "A Systematic Study of Gas and Water Coning by Potentiometric Models," JPT, Aug. 1964, p. 923.
- Cohen, M.F. 1989, "Recovery Optimization in a Bottom/Edge Water-Drive Gas

Reservoir, Soehlingen Schneverdinge," paper SPE 19068 SPE Gas Technology Symposium, Dallas, June 7-9.

- Dake LP (2004) The practice of reservoir engineering, revised edition, development in petroleum science. Elsevier, London, p 572
- Economides, M.J.; Hill, A.D.; Ehlig-Economides, C. Petroleum Production Systems, 18th ed.; Prentice Hall PTR: Upper Saddle River, NJ, USA, 2008.
- Elphick J and Seright R: "A Classification of Water Problem types," SPE Tchnical Conference and Exhibitions, Houston Texas, USA, August, 1997.
- Fayzullin, M.; Tippel, P.; Gonzalez, J.; Egger, S. Understanding ExcessiveWater Production in Highly Faulted Mature Gas Condensate Field: From Well Operations to Revival of Integrated History Matching. Presented At the IADC/SPE Asia Pacific Drilling Technology Conference, Bangkok, Thailand, 25–27 August 2014.
- Hirsch R (2008) Mitigation of maximum world oil production: shortage scenarios. Energy Policy 36(2):881–889
- Hoyland, L. A., Papatzacos, P., and Skjaeveland, S. M., "Critical Rate for Water Coning: Correlation and Analytical Solution," *SPERE,* Nov. 1989, p. 495.
- Ho¨o¨k M (2009) Depletion and decline curve analysis in crude oil production doctoral thesis, Uppsala University
- Ho¨o¨k M, So¨derbergh B, Jakobsson K, Aleklett K (2009) "The evolution of giant oil field production behavior." Nat Resources 18(1):39–56
- Joshi, S. D., "Augmentation of Well Productivity Using Slant and Horizontal Wells," J. of Petroleum Technology, June 1988, pp. 729–739.
- Joshi, S., Horizontal Well Technology. Tulsa, OK: Pennwell Publishing Company, 1991.
- Muskat, M., and Wyckoff, R. D., "An Approximate Theory of Water Coning in Oil Production," Trans. AIME, 1953, pp. 114, 144.

- Ozkan, E., and Raghavan, R., "Performance of Horizontal Wells Subject to Bottom Water Drive," SPE Paper 18545, presented at the SPE Eastern Regional Meeting, Charleston, West Virginia, Nov. 2–4, 1988.

- Papatzacos, P., Herring, T. U., Martinsen, R., and Skjaeveland, S. M., “Cone Breakthrough Time for Horizontal Wells,” SPE Paper 19822, presented at the 64th SPE Annual Conference and Exhibition, San Antonio, TX, Oct. 8–11, 1989.
- Permana, D.; Ferdian, G.; Aji, M.; Siswati, E. Extracting Lessons Learned of 35 Water Shut-o_ Jobs in MatureFields to Improve Success Ration of Water Shut-off Job. Presented at the SPE/IATMI Asia Pacific Oil & Gas Conference and Exhibition, Bali, Indonesia, 20–22 October 2015.
- Tarek Ahmed: “Reservoir Engineering Handbook,” Gulf Professional Publishing, Massachusets, USA, 2000
- Yortsos, Y.C.; Choi, Y.; Yang, Z.; Shah, P.C. Analysis and Interpretation of Water/Oil Ratio in Waterfloods SPE J. **1999**, 4, 413–424.