Integrated Performance Analysis and Optimization of Reservoir Management Strategies in a Black Oil Reservoir Using CMG IMEX Simulator

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Abstract

Effective reservoir management is critical for maximizing hydrocarbon production while maintaining the long-term health of the reservoir. This study investigates the performance evaluation and optimization of a black oil reservoir using CMG IMEX, a robust reservoir simulation tool. The objective is to analyze various production strategies, including natural depletion, water injection, and gas injection, to identify the optimal methods for maximizing recovery and ensuring sustainable reservoir performance.

A detailed reservoir model was constructed, incorporating the reservoir's geological and petrophysical properties such as porosity, permeability (kx, ky, kz), fluid properties, and saturation distributions. The model was calibrated with field data to reflect realistic reservoir conditions, including pressure and saturation levels. Sensitivity analyses were conducted to evaluate the impact of operational parameters such as injection rates, well placement, and production constraints on cumulative oil recovery and production efficiency.

Simulation results highlighted the significant role of reservoir heterogeneity in influencing fluid flow and recovery rates. For instance, regions with high permeability facilitated rapid fluid movement, whereas low-permeability zones posed challenges for sweep efficiency. The study identified optimal operational parameters that enhance recovery and delay the onset of pressure depletion. The findings demonstrate how reservoir simulation can provide actionable insights into production planning and operational decision-making.

This research underscores the importance of using advanced simulation tools like CMG IMEX to model complex reservoirs and optimize production strategies. By bridging theoretical reservoir modeling with practical field applications, this study provides a robust framework for improving hydrocarbon recovery and supporting sustainable reservoir management practices. The insights gained are applicable to similar black oil reservoirs, offering valuable guidance for field development planning and optimization efforts.

Keywords: Black Oil Reservoir, Reservoir Simulation, CMG IMEX Simulator, Sensitivity Analysis, Production Optimization, Reservoir Heterogeneity, Natural Depletion, Water Injection, Gas Injection, Well Placement Strategy, Oil Recovery Performance, Reservoir Management, Field Development Planning.

INTRODUCTION

This study aims to analyse and optimize the performance of a black oil reservoir under various production scenarios using CMG IMEX simulation software. The research involves constructing a detailed reservoir model that reflects the reservoir's unique geological and petrophysical characteristics, such as heterogeneity, fluid properties, and initial conditions. This introduction provides an overview of the reservoir setup, modelling methodology, and the importance of sensitivity studies to the project.

Reservoir Characteristics

The reservoir consists of nine distinct layers, with key properties such as permeability, porosity, thickness, and depth varying across the layers. The top of the reservoir begins at a depth of **996 meters**, with the thickness of each layer ranging from **15 to 30 meters**. Detailed properties of the layers are as follows:

- **Permeability (K)**: Varies significantly between layers, ranging from **100 md to 315 md**, indicating varying flow capacities across the reservoir.
- **Porosity**: Ranges from **0.2 to 0.325**, reflecting differences in the storage capacity of hydrocarbons in each layer.
- **Layer Thickness (h)**: Layers are between **15 meters to 30 meters**, contributing to the reservoir's overall net pay thickness of **176 meters**.
- **Top Depth (dtop)**: Begins at **996 meters** and extends to **1142 meters**.

These variations highlight the reservoir's heterogeneity, which significantly influences fluid flow and recovery efficiency. Such detailed characterization is critical for accurately simulating reservoir behavior under different production scenarios.

Model Development and Well Design

<u>Reservoir Properties</u>

1. **Grid Dimensions**:
   - The reservoir model spans **75 x 65 x 9** grid cells.
   - Each grid cell measures **20 m x 10 m** in the X and Y directions, respectively.
   - Vertical thickness across the 9 layers varies between **15 m to 30 m**, with the total thickness summing to approximately **176 meters**.

2. **Layer Properties**
   - **Porosity (Fraction):**
     Ranges from 0.20 to 0.325 across layers.
   - **Permeability (kx in md):**
     Varies between 100 md and 315 md, indicating reservoir heterogeneity.
   - **Top Depth (dtop):**
     Starts at 996 meters and extends to 1142 meters.

Layer	Porosity (Fraction)	Permeability (kx in md)	Thickness (h in m)	Top Depth (dtop in m)
1	0.25	125	23	996
2	0.265	156	17	1019
3	0.31	100	20	1036
4	0.325	250	21	1056
5	0.2	180	15	1077
6	0.275	248	15	1092
7	0.289	315	20	1107
8	0.2	150	15	1127
9	0.26	135	30	1142

Table: Layer Properties.

3. Reservoir Model Visualization

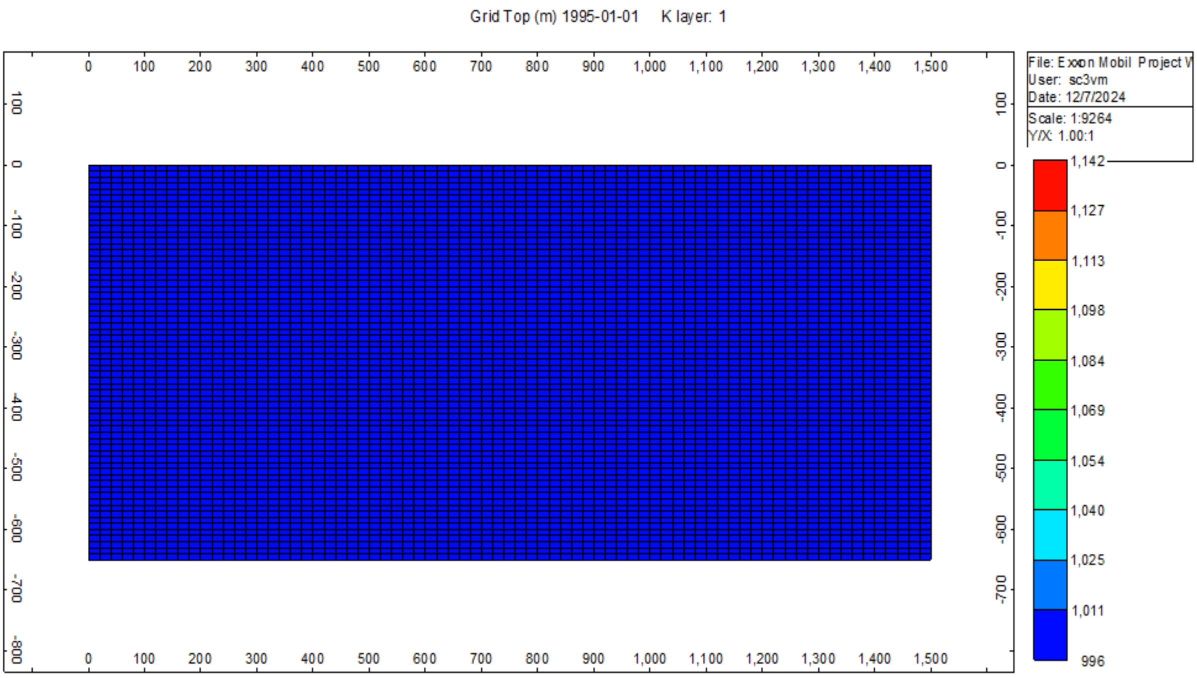

Image 1: Top View of Reservoir Grid

This image set visualizes the reservoir's structure. The top view (Image 1) shows the grid layout of the first layer, spanning 75 x 65 cells, with a colour gradient indicating depth variations. This aids in analysing the reservoir's surface extent and planning well placement. The 3D model (Image 2) depicts the vertical structure, ranging from 996 m to 1142 m, with color-coded depth layers. Four wells (Well-1001 to Well-1004) are strategically placed to target high-permeability zones, optimizing hydrocarbon recovery.

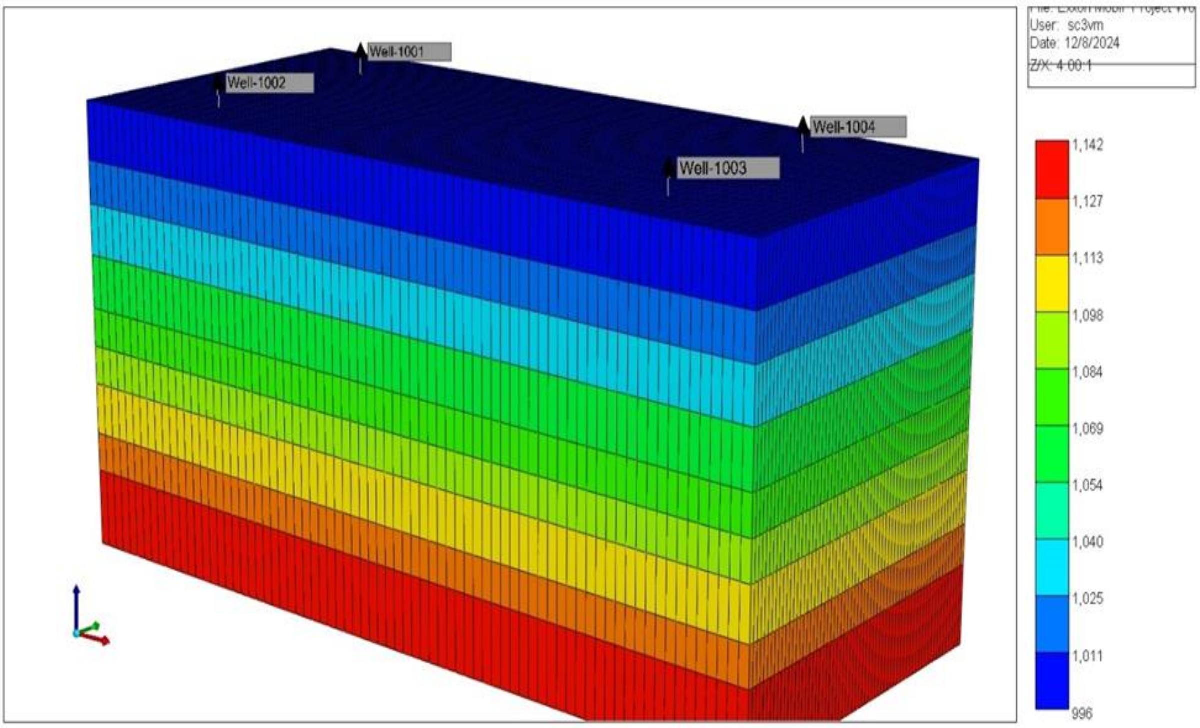

Image 1: 3D View of Reservoir Grid

4. Fluid Properties

The fluid properties provide crucial data for understanding the behaviour of oil, water, and gas under reservoir conditions. These parameters are essential for accurate reservoir modelling and production strategy optimization. The following data will be included in this section:

Fluid Characteristics:

- **Oil Density**: 823 kg/m³
- **Water Density**: 1000 kg/m³
- **Gas Specific Gravity**: 1.03 (relative to air)
- **Undersaturated Oil Compressibility**: 1.06E-6 1/kPa
- **Water Compressibility**: 7.3822E-7 1/kPa
- **Water Formation Volume Factor**: 1.005
- **Water Viscosity**: 1 cp
- **Bubble point pressure:** 9570 kPa

PVT Data

This table presents the properties of different fluids in the reservoir, including oil, water, and gas. It outlines key parameters such as density, viscosity, and formation volume factors (Bo, Bw, Bg) at various pressures and temperatures. These values are crucial for understanding fluid behaviour under reservoir conditions, helping to predict flow dynamics and optimize production strategies. The data supports accurate modelling and sensitivity analysis for enhanced reservoir management.

Pressure (kPa)	Rs (m^3/m^3)	Bo (m^3/m^3)	Eg	Oil Viscosity (cp)	Gas Viscosity (cp)
101.325	1.35	1.03834	0.8724	1.67759	0.010475
732.57	5.65	1.04952	6.442	1.47259	0.010603
1363.82	10.67	1.06294	12.2578	1.29954	0.010777
1995.06	16.14	1.07797	18.3406	1.16041	0.010987
2626.31	21.95	1.09435	24.7129	1.04829	0.011232
3257.55	28.04	1.11193	31.3983	0.95675	0.011512
3888.8	34.36	1.13059	38.4215	0.8809	0.011831
4520.04	40.89	1.15026	45.8064	0.81716	0.012194
5151.29	47.61	1.17087	53.5751	0.76288	0.012603
5782.53	54.48	1.19238	61.7444	0.71613	0.013066
6413.78	61.51	1.21473	70.3227	0.67543	0.013587
7045.02	68.68	1.23789	79.3044	0.63969	0.014173
7676.27	75.98	1.26183	88.6648	0.60804	0.01483
8307.51	83.39	1.28651	98.3549	0.5798	0.015562
8938.76	90.93	1.31191	108.3	0.55446	0.016371
9570	98.57	1.338	118.4	0.53156	0.017257
9656	99.61	1.34161	119.781	0.52861	0.017383
9742	100.67	1.34523	121.164	0.5257	0.017511
9828	101.72	1.34886	122.546	0.52283	0.01764
9914	102.77	1.35251	123.928	0.51999	0.01777
10000	103.83	1.35616	125.31	0.51719	0.017901

Table: PVT Data.

Rock Fluid Contact

Water Saturation (SW)	Water Relative Permeability (KRW)	Oil Relative Permeability (KROW)
0.25	0	1
0.5	0.8	0.5
0.7	1	0
1	1	0

Table: Water-Oil Relative Permeability

Liquid Saturation (SL)	Gas Relative Permeability (KRG)	Oil Relative Permeability (KROG)
0.25	0.98	0
0.3	0.95	0
0.4	0.85	0
0.5	0.7	0.001
0.55	0.6	0.01
0.6	0.4	0.022
0.7	0.19	0.098
0.75	0.12	0.21
0.8	0.05	0.48
0.85	0	1
1	0	1

Table: Liquid-Gas Relative Permeability

Explanation of Parameters:

- **Pressure (kPa):** Reservoir pressure at different depths.
- **Rs (m^3/m^3):** Gas dissolved in oil at a specific pressure.
- **Bo (m^3/m^3):** Oil formation volume factor (expansion of oil at reservoir conditions).
- **Eg:** Expansion factor for gas.
- **Oil Viscosity (cp):** Viscosity of the oil under reservoir conditions.
- **Gas Viscosity (cp):** Viscosity of the gas under reservoir conditions.

5. Initial Conditions

The reservoir's initial conditions are critical for evaluating its performance and recovery strategies. The following parameters define the reservoir's starting state:

- **Reference Depth:**
  The reference depth of the reservoir is 1100 meters.
- **Reference Pressure:**
  The initial pressure at the reference depth is 10500 kPa.
- **Gas-Oil Contact (GOC):**
  The depth of the gas-oil contact is identified at 1035 meters.
- **Water-Oil Contact (WOC):**
  The water-oil contact is located at a depth of 1135 meters.
- **Initial Volumetric Data:**
  Based on the simulation results, the initial oil, water, and gas in place are as follows:
  - **Total Oil in Place:** 1.53×10^7 m^3
  - **Total Water in Place:** 1.83×10^7 m^3
  - **Total Gas in Place:** 2.43×10^9 m^3
- **Pore Volumes:**
  - **Hydrocarbon Pore Volume:** 27741 million m^3
  - **Total Pore Volume:** 45996 million m^3

The initial conditions of the reservoir provide a clear understanding of its hydrocarbon distribution and recovery potential. The reference depth of **1100 meters** and pressure of **10500 kPa** serve as the baseline for reservoir modeling. The gas-oil contact at **1035 meters** and water-oil contact at **1135 meters** highlight the fluid phase boundaries. The reservoir contains significant hydrocarbon resources, with **1.53×10^7 m^3** of oil and **2.43×10^9 m^3** of gas in place. These values, along with the pore volumes, guide well placement and production strategies for optimal recovery.

1. Well Locations and Perforation Data

Well Name	X-Location	Y-Location	Z (Layers)	Perforation Intervals	Gas Viscosity (cp)
Well-1001	12	16	4–7	Layer 4: 1056–1077 m, Layer 5: 1077–1092 m, Layer 6: 1092–1107 m, Layer 7: 1107–1127 m	0.010475
Well-1002	12	54	4–7	Layer 4: 1056–1077 m, Layer 5: 1077–1092 m, Layer 6: 1092–1107 m, Layer 7: 1107–1127 m	0.010603
Well-1003	63	54	4–7	Layer 4: 1056–1077 m, Layer 5: 1077–1092 m, Layer 6: 1092–1107 m, Layer 7: 1107–1127 m	0.010777
Well-1004	63	16	4–7	Layer 4: 1056–1077 m, Layer 5: 1077–1092 m, Layer 6: 1092–1107 m, Layer 7: 1107–1127 m	0.010987

Table: Well Locations & Perforation Data

The table highlights the locations and perforation intervals for four production wells in the reservoir. Each well is strategically placed to target high-permeability zones, ensuring optimal hydrocarbon recovery. The wells are perforated across layers 4 to 7, with intervals ranging from 1056 meters to 1127 meters. This perforation strategy focuses on productive layers with favourable properties, such as higher permeability and porosity. The uniform perforation plan across all wells ensures consistent production rates and efficient reservoir drainage. The spacing and depth selection aim to minimize interference between wells and maximize pressure support. This design reflects a balanced approach to enhancing recovery and maintaining reservoir integrity.

2. Constraints

The production constraints outlined for the reservoir are essential to ensure efficient hydrocarbon recovery while maintaining reservoir stability. These guidelines help avoid operational challenges, such as excessive pressure depletion and unwanted fluid production.

Key constraints include maintaining a **maximum stock tank oil rate of 500 m³/day** to support sustainable extraction and a **minimum bottom-hole pressure of 1000 kPa** to prevent pressure collapse. Additionally, shut-in conditions are applied to wells when the **gas-oil ratio (GOR)** exceeds **3000 m³/m³**, the **water cut surpasses 95%**, or the **oil production rate drops below 6 m³/day**. These conditions are aimed at maintaining operational efficiency and mitigating risks associated with water and gas breakthroughs.

The **production duration** is set from **January 1, 1995, to December 31, 2035**, with a **uniform base production rate of 200 m³/day**. This consistent rate ensures controlled depletion of reservoir resources, reducing the risks of overproduction.

The table below summarizes these constraints for easy reference:

Constraint	Value
Production Duration	January 1, 1995 – December 31, 2035
Uniform Production Rate	200 m^3/day (base case)
Maximum Stock Tank Oil Rate	500 m^3/day
Minimum Bottom Hole Pressure	1,000 kPa
Shut-In Gas-Oil Ratio	3,000
Shut-In Water Cut	0.95
Shut-In Stock Tank Oil Rate	6 m^3/day

Significance of the Study

This study plays a crucial role in advancing the understanding of reservoir performance and optimizing production strategies in black oil reservoirs. By leveraging advanced simulation tools like **CMG IMEX**, the project provides a comprehensive framework for evaluating different production scenarios, such as natural depletion, water flooding, and gas injection.

The insights gained from this study help identify key operational parameters, such as injection rates and perforation strategies, which significantly impact recovery efficiency and reservoir sustainability. Additionally, the research addresses the challenges posed by reservoir heterogeneity, ensuring that recovery strategies are tailored to maximize hydrocarbon production while maintaining reservoir integrity.

The findings are not only valuable for field development planning but also offer a roadmap for sustainable reservoir management. By optimizing production and minimizing risks such as water and gas breakthroughs, this study contributes to improving the economic viability of reservoirs while aligning with the industry's long-term goals of sustainable resource utilization.

Sustainability Perspective

This study emphasizes the importance of sustainable reservoir management practices to maximize hydrocarbon recovery while minimizing environmental and operational risks. By optimizing production strategies, such as maintaining reservoir pressure and preventing excessive gas and water production, the project ensures that resources are extracted efficiently without compromising the reservoir's long-term health.

The project also aligns with the industry's shift toward environmentally responsible resource management. By reducing water and gas breakthroughs and implementing well-targeted perforation strategies, it minimizes waste and enhances operational efficiency. These practices not only improve the economic life of the reservoir but also support sustainable energy development, ensuring that valuable hydrocarbon resources are utilized in the most efficient and responsible manner.

This approach highlights the dual focus on achieving economic goals and preserving the reservoir for future use, making it a valuable contribution to sustainable oil and gas production.

In addition to optimizing recovery, this study promotes the sustainable use of energy resources by reducing unnecessary environmental impact through careful operational planning. The focus on minimizing water cut and gas flaring contributes to lower environmental footprints, ensuring compliance with global sustainability standards. By extending the reservoir's productive life, this approach reduces the need for additional exploration and development, conserving resources and minimizing ecological disruption. Furthermore, the integration of advanced simulation techniques enables precise decision-making, reducing energy and material wastage during production operations.

Base Case Modelling and Simulation

The base case simulation provides a detailed analysis of the reservoir's performance under current conditions. It serves as a benchmark to evaluate reservoir and well productivity and to identify potential areas for optimization.

1. **Grid System and Well Placement**
   - **Grid System**:
     The reservoir model consists of **43,875 blocks**, representing the spatial extent of the reservoir with **4 active wells**.
   - **Well Placement**:
     Wells are strategically positioned within the grid to maximize hydrocarbon recovery while ensuring efficient drainage. The perforated layers target high-permeability zones for optimal fluid flow.

2. **Reservoir Simulation Results**
   The base case simulation captures the reservoir and well performance metrics over a production duration of 14,944 days (~41 years). Key results include**:**

Metric	**Oil (MSM^3)**	**Gas ($MMSM^3$)**	**Water (MSM^3)**
Cumulative Production	3,408.80	826.62	4.5196
Cumulative Injection	NA	0	0
Current Fluids In Place	11,963	1,606.70	18,295
Production Rates	0	0	0
Injection Rates	NA	0	0

Table: Reservoir Simulation Results

3. **Reservoir Pressure**:
    - The average reservoir pressure, excluding the water zone, is recorded at **6,250.543 kPa**, indicating a significant pressure drop due to production.
    - **Fluid Behavior**:
      The simulation demonstrates a cumulative oil production of **3,408.8 MSM³**, with minimal water production (**4.5196 MSM³**), indicating effective reservoir management during the base case.
    - **Gas Production**:
      Cumulative gas production is recorded at **826.62 MMSM³**, with no observed gas lift or injection, highlighting a focus on natural depletion in the base case.

4. **Reservoir Performance Analysis**
    1. **Fluid Production**:
        - **Cumulative Oil Production**:
          The total oil produced during the simulation period is **3,408.8 MSM³**, reflecting effective drainage of hydrocarbons from high-productivity zones.
    - **Cumulative Gas Production**:
      A total of **826.62 MMSM³** of gas has been produced, indicating active gas recovery through natural depletion.
    - **Cumulative Water Production**:
      Minimal water production of **4.5196 MSM³** suggests effective management of water encroachment into the production zones.
    2. **Fluids in Place**:
        - **Oil In Place**: The current remaining oil in the reservoir is **11,963 MSM³**, highlighting a significant resource base for future recovery strategies.
        - **Gas In Place**:
          1,606.7 MMSM³ of gas remains in the reservoir, providing opportunities for optimized gas recovery.
        - **Water In Place**:
          The reservoir contains **18,295 MSM³** of water, indicating a need to monitor potential water breakthroughs.

    3. **Reservoir Pressure**:
       The average reservoir pressure, excluding the water zone, is recorded at **6,250.543 kPa**. This indicates a significant pressure drawdown due to continuous production, necessitating pressure maintenance strategies to sustain recovery.

    4. **Well and Field Performance**:
        - The reservoir model includes **4 active wells**, which are strategically located to target high-permeability zones.
        - Despite the cumulative production data, the current production rates for oil, gas, and water are recorded as **zero**, suggesting potential operational constraints or reservoir depletion in some zones.

5. Group Production Plots

The production performance of the reservoir is summarized using **Group Production Plots**, highlighting key parameters such as liquid production rates, cumulative oil production, water cut, and gas-oil ratio over the simulation period (1995–2035). Below is an explanation of each plot:

1. **Liquid Rate (SC)**:
   The liquid production rate remains steady at approximately **500 m³/day**, reflecting controlled production during the base case simulation.
2. **Cumulative Oil Production**:
   The second plot displays cumulative oil production trends along with the corresponding bottom-hole pressure. Cumulative oil recovery increases steadily, reaching significant levels, but the observed decline in pressure emphasizes the need for pressure maintenance strategies.
3. **Water Cut (SC)**:
   The water cut remains low throughout most of the simulation but spikes sharply toward the later stages, indicating potential water encroachment as the reservoir depletes.
4. **Gas-Oil Ratio (SC)**:
   The gas-oil ratio remains stable during early production but increases over time, reflecting gas breakthrough due to pressure depletion.

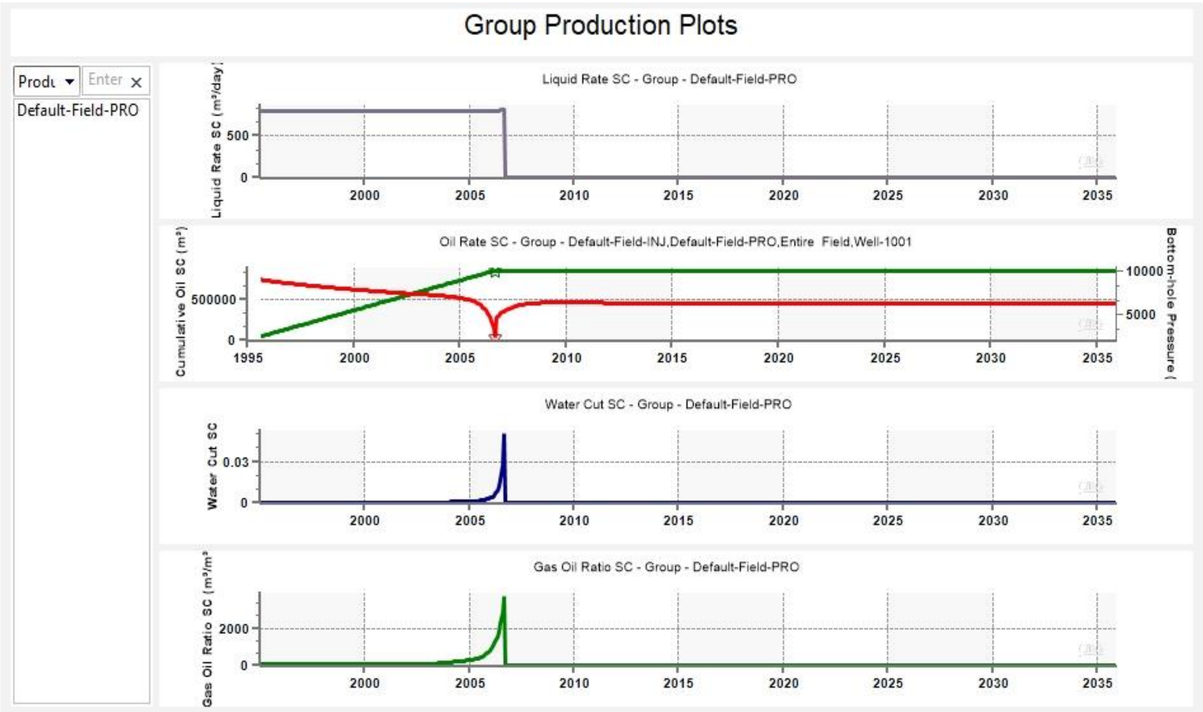

Image: Group Production Plots

Significance of the Plots

These plots provide critical insights into reservoir and well performance under base case conditions:

- **Liquid Production Stability**: Consistent production rates indicate efficient reservoir management during early stages.
- **Pressure Decline**: The observed decline in reservoir pressure suggests the need for enhanced recovery techniques, such as water or gas injection, to sustain production.
- **Water and Gas Breakthrough**: The late-stage increase in water cut and gas-oil ratio highlights challenges that must be addressed through operational adjustments and optimization.

6. Discussion and Insights

The base case simulation highlights the following key performance metrics:

- **Hydrocarbon Recovery**: The cumulative oil and gas production demonstrates the reservoir's potential, but further strategies are needed to maximize recovery from remaining hydrocarbons.
- **Pressure Maintenance**: The observed pressure drop emphasizes the importance of implementing pressure support techniques, such as water or gas injection, to sustain production and enhance reservoir performance.
- **Minimal Water Production**: The low cumulative water production indicates efficient reservoir management, with limited water encroachment into the production zones.

Sensitivity Analysis Studies and Results Discussion

Objective of Sensitivity Analysis

The sensitivity analysis (SA) aims to evaluate the influence of key reservoir and operational parameters on the selected objective functions, such as cumulative oil recovery, reservoir pressure, water cut, and gas-oil ratio. This process helps identify the parameters most critical to optimizing reservoir performance, ensuring a targeted and efficient approach to production strategies.

By systematically varying these parameters, SA provides a deeper understanding of how changes in reservoir characteristics, such as porosity, permeability, and Kv/Kh ratio, influence production outcomes. This information enables the development of robust strategies to maximize oil recovery, maintain reservoir pressure, and minimize operational risks such as gas and water breakthroughs. Moreover, sensitivity analysis not only highlights the parameters that need optimization but also identifies areas where interaction effects can negatively impact production efficiency. The insights gained from this study guide informed decision-making, allowing us to improve operational efficiency, mitigate risks, and achieve sustainable production goals. The results of SA serve as a foundation for further reservoir management and optimization efforts, aligning with both short-term production targets and long-term field development strategies.

Cross Plots for Kv/Kh Ratio vs. Cumulative Oil Production (Well 1 to Well 4)

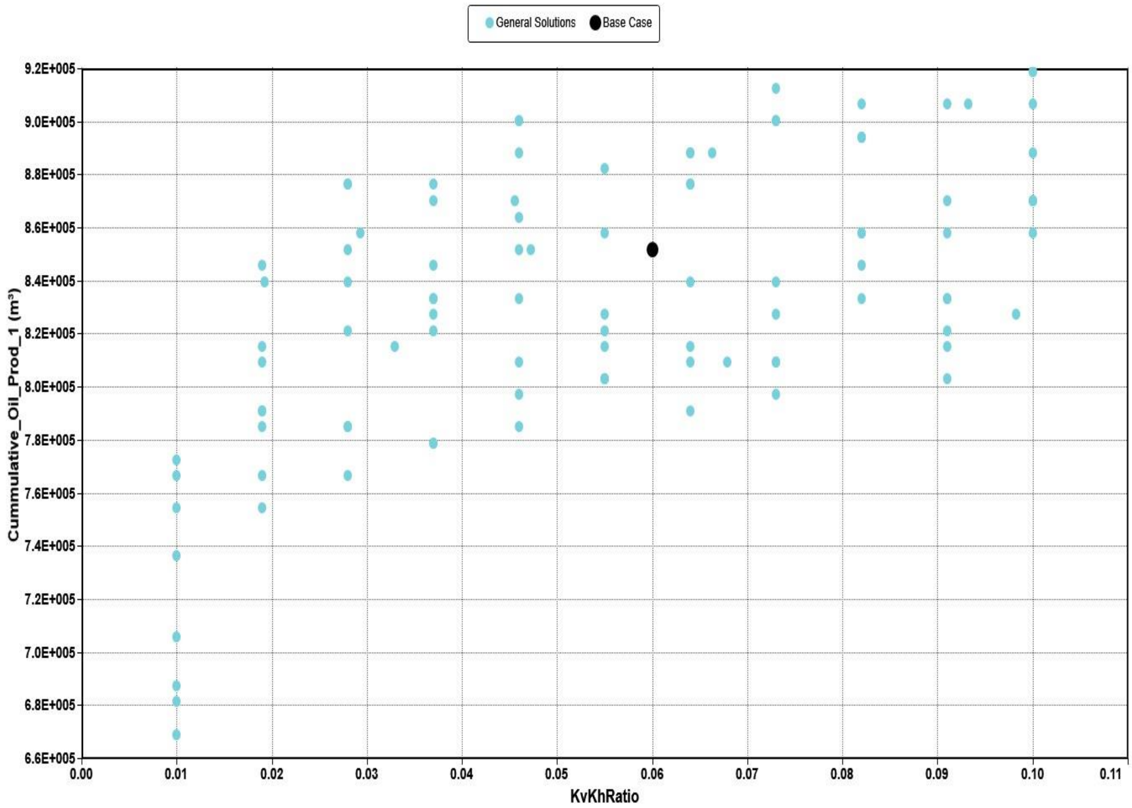

Image 1: Cross Plot for Well 1 - Kv/Kh Ratio vs. Cumulative Oil Production

Explanation of Cross Plots

These cross plots illustrate the relationship between the **Kv/Kh ratio** (vertical-to-horizontal permeability ratio) and the **cumulative oil production** for individual wells (Well 1 to Well 4).

Trend Observations:
For all wells, higher Kv/Kh ratios (greater than 0.08) correlate with improved cumulative oil production. This trend reflects enhanced vertical fluid connectivity, enabling better hydrocarbon recovery from deeper layers of the reservoir. However, excessive Kv/Kh ratios may also result in premature water or gas breakthrough.

Base Case Comparison:
The black point in each plot represents the **base case scenario**. It serves as a benchmark to evaluate how modifications to the Kv/Kh ratio affect production outcomes relative to the base case.

Performance Variations:
The results vary slightly across wells due to differences in geological and operational conditions. Wells located in high-permeability zones benefit more significantly from higher Kv/Kh ratios compared to those in relatively lower-permeability areas.

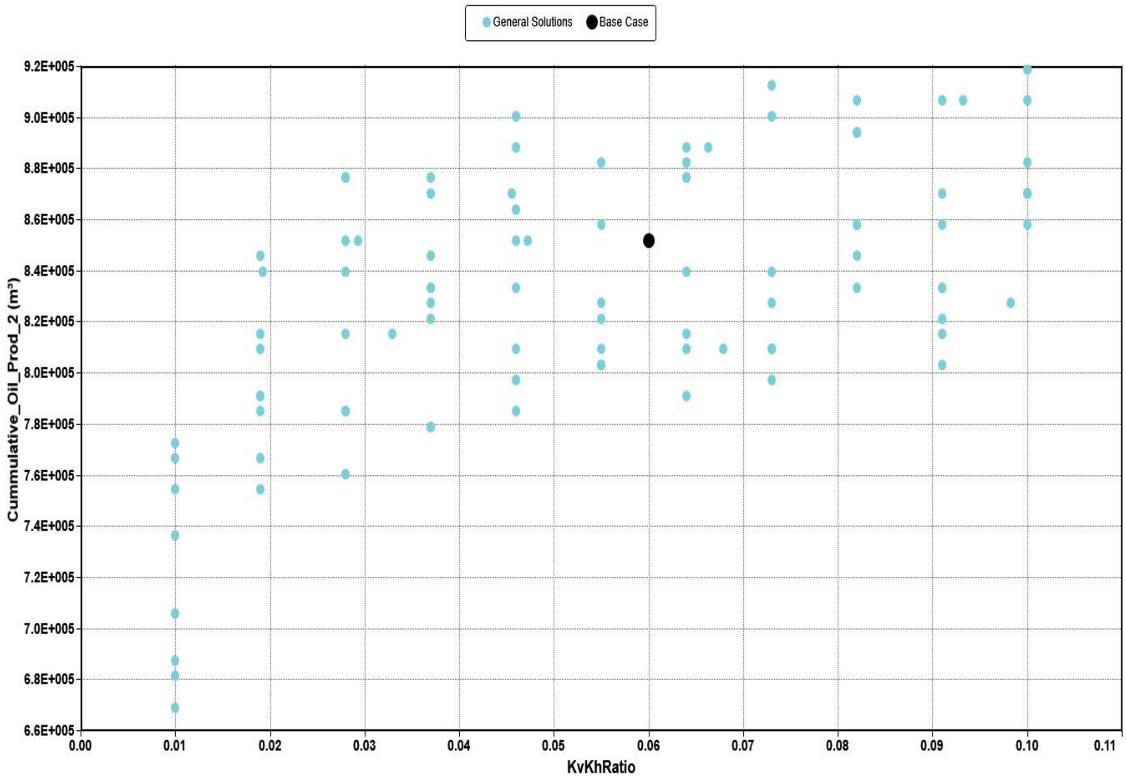

Image 2: Cross Plot for Well 2 - Kv/Kh Ratio vs. Cumulative Oil Production

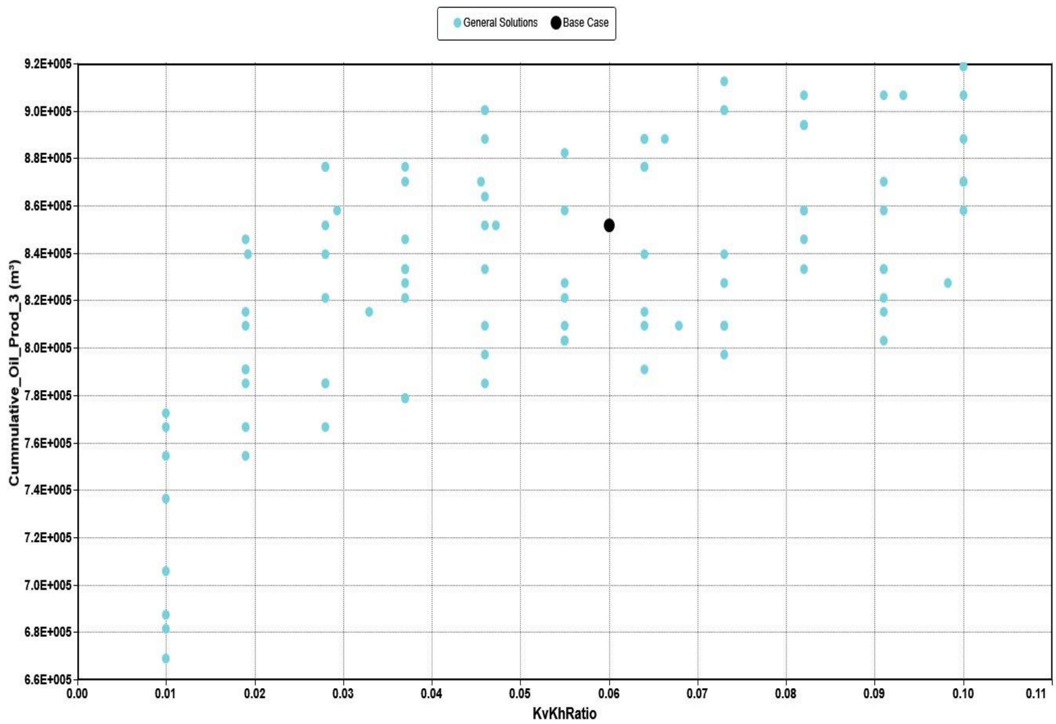

Image 3: Cross Plot for Well 3 - Kv/Kh Ratio vs. Cumulative Oil Production

Histograms of Cumulative Oil Production for Wells 1 to 4

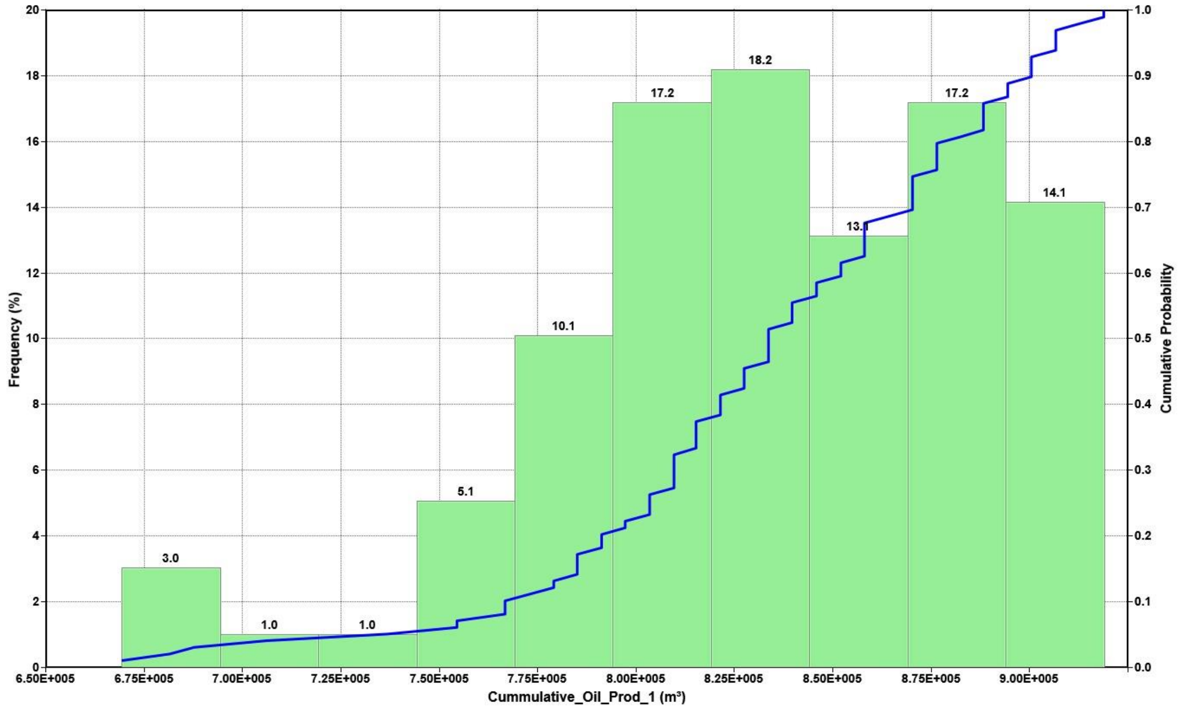

Image 1: Histogram of Cumulative Oil Production for Well 1

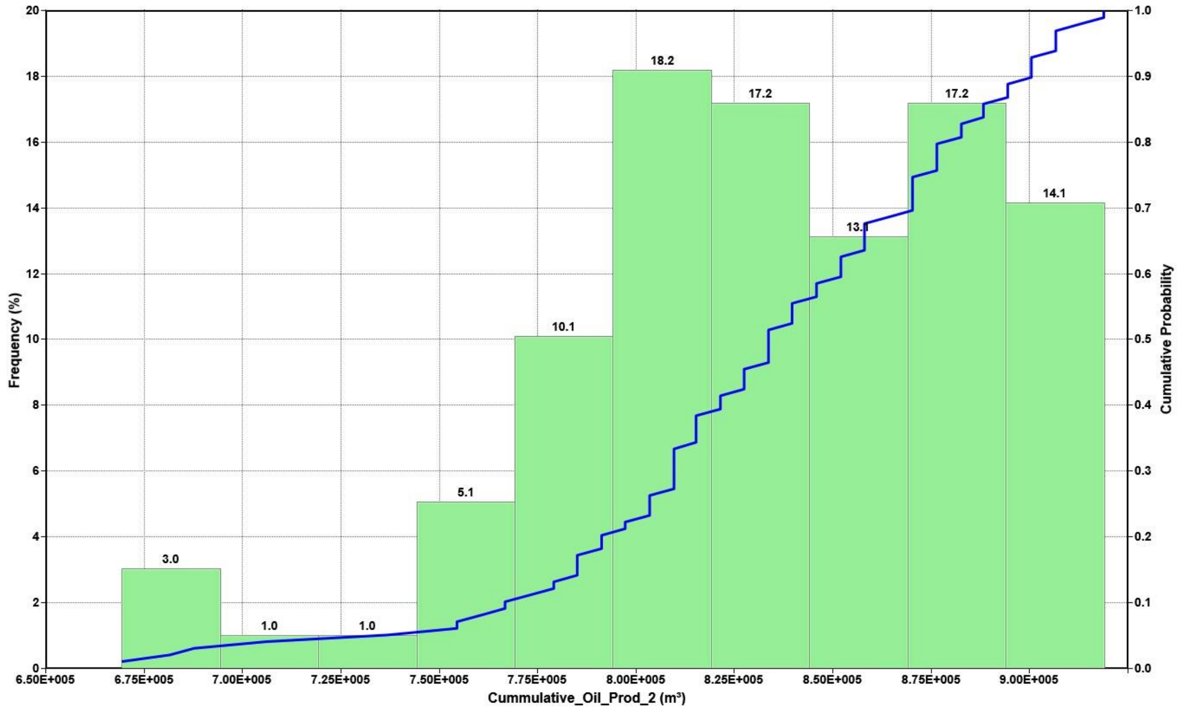

Image 2: Histogram of Cumulative Oil Production for Well 2

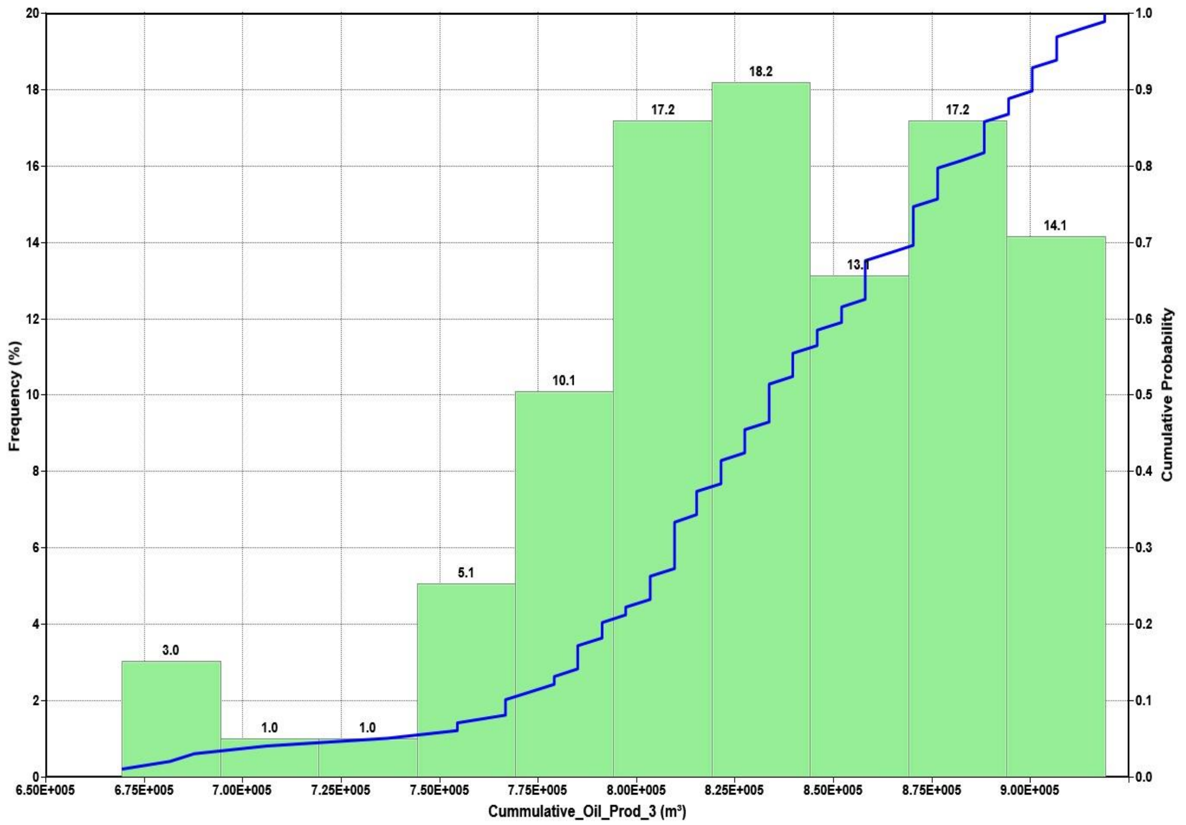

Image 3: Histogram of Cumulative Oil Production for Well 3

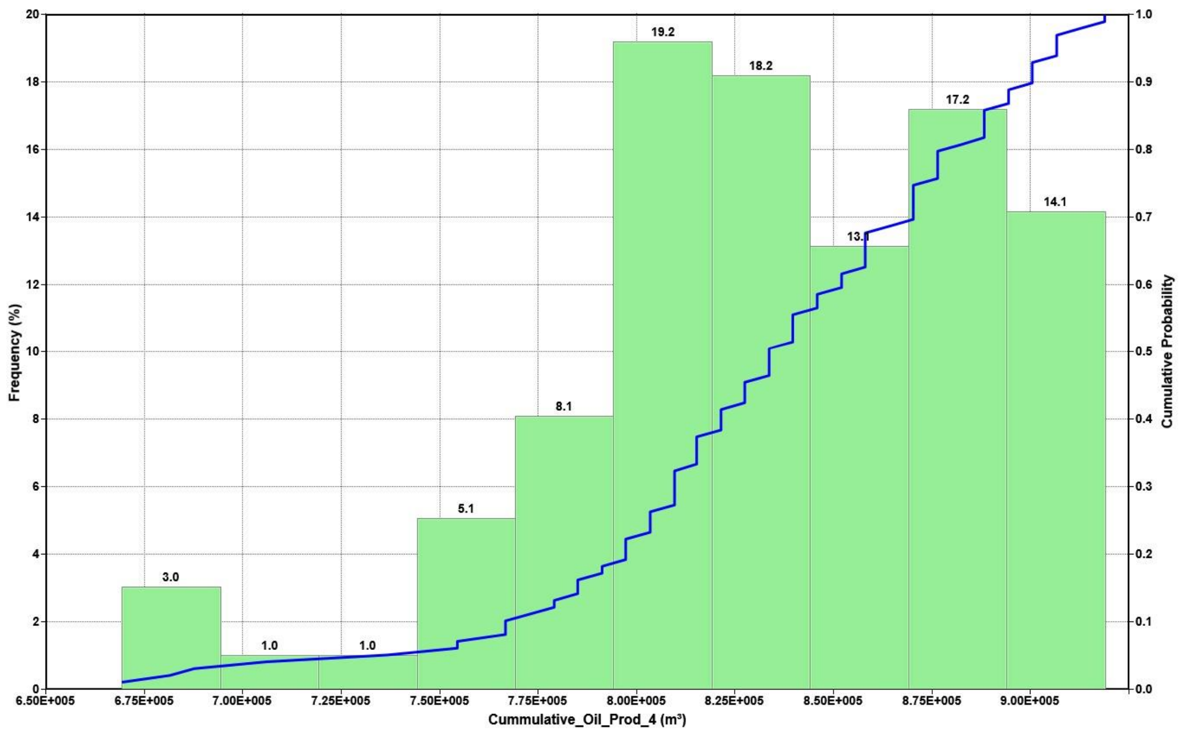

Image 4: Histogram of Cumulative Oil Production for Well 4

Explanation of Histograms

The histograms depict the distribution of **cumulative oil production (m^3)** for each well, highlighting the frequency of production outcomes under different sensitivity scenarios. The following trends are observed:

1. **Frequency Distribution**:
   Each bar represents the percentage frequency of production outcomes in each range. The green bars show higher frequencies in the range of **8.0×10^5 to 9.0×10^5 m^3**, indicating the most probable production levels.

2. **Cumulative Probability Curve**:
   The blue line represents the cumulative probability, showing the likelihood of achieving a specific production level or less. A steep increase in the curve around **8.5×10^5 m^3** indicates higher production reliability within this range.

3. **Performance Trends**:
   All wells exhibit a similar distribution, with Well 1 slightly skewed toward lower production levels compared to the others, reflecting variations in reservoir conditions and permeability zones.

Proxy Analysis

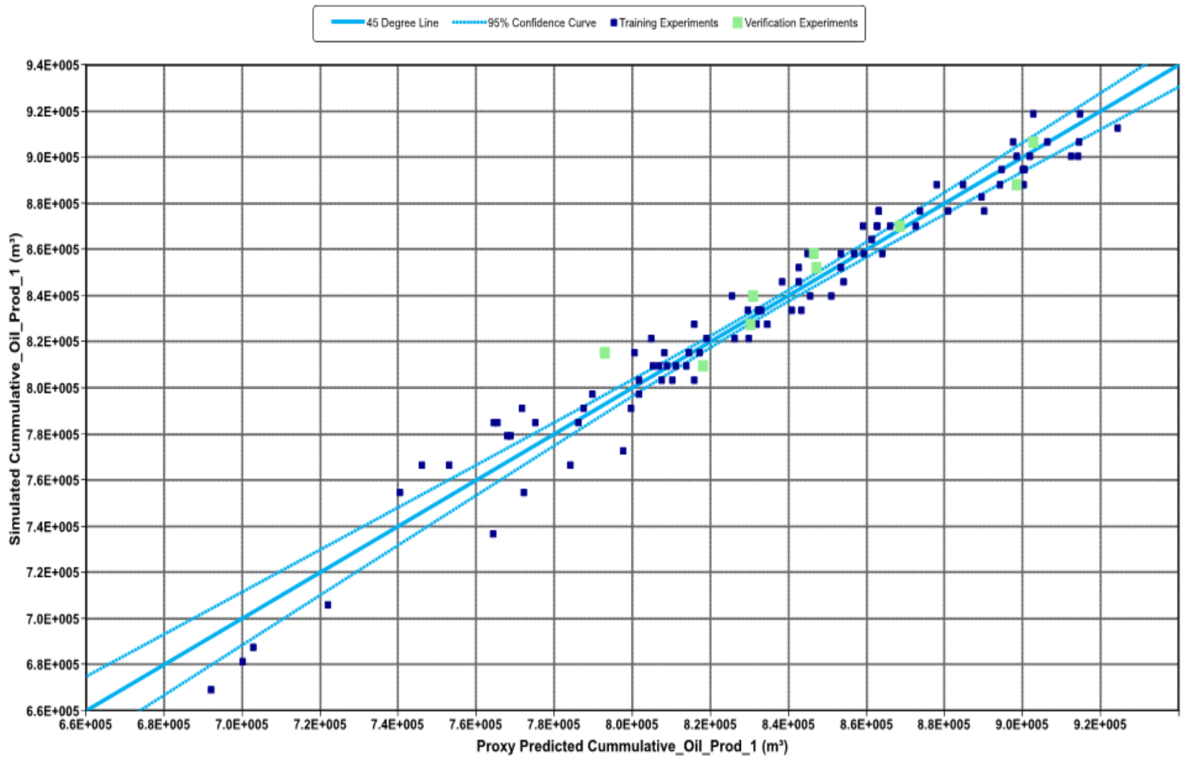

Image: Model QC

The plot shows a high correlation between proxy-predicted and simulated cumulative oil production, with most data points falling within the 95% confidence interval, validating the accuracy of the proxy model. The alignment along the 45-degree line demonstrates the model's reliability.

Summary of Fit Statistics

Objective Function Name: Cummulative_Oil_Prod_1

Model Classification: Reduced Simple Quadratic (alpha=0.1) (R2-training=0.961, R2-verification=0.925)

Summary of Fit

R-Square	0.961196
R-Square Adjusted	0.957883
R-Square Prediction	0.952430
Mean of Response	831951
Standard Error	11085

Analysis of Variance

Source	Degrees of Freedom	Sum of Squares	Mean Square	F Ratio	Prob > F
Model	7	2.49583E+11	3.56547E+10	290.167	<0.00001
Error	82	1.00759E+10	1.22877E+08		
Total	89	2.59659E+11			

Effect Screening Using Normalized Parameters (-1, +1)

Term	Coefficient	Standard Error	t Ratio	Prob > |t|	VIF
Intercept	854991	2743.74	311.615	<0.00001	0.00
KvKhRatio(0.01, 0.1)	49944.3	1882.56	26.5299	<0.00001	1.02
PERMI_L1(187.5, 312.5)	3806	1878.18	2.02643	0.04597	1.02
PERMJ_L2(135, 225)	1506.95	1848.61	0.815182	0.41733	1.02
Porosity(0.24375, 0.40625)	57735.2	1955.73	29.521	<0.00001	1.14
KvKhRatio*KvKhRatio	-54040.6	3432.31	-15.7447	<0.00001	1.07
PERMI_L1*PERMI_L1	-9593.15	3487.33	-2.75086	0.00731	1.10
PERMJ_L2*PERMJ_L2	5786.08	3377.91	1.71292	0.09051	1.05

Coefficients in Terms of Actual Parameters

Term	Coefficient
Intercept	400115
KvKhRatio	4.04541E+06
PERMI_L1	1288.82
PERMJ_L2	-995.149
Porosity	710587
KvKhRatio*KvKhRatio	-2.66867E+07
PERMI_L1*PERMI_L1	-2.45585
PERMJ_L2*PERMJ_L2	2.85732

Equation in Terms of Actual Parameters

```
Cummulative_Oil_Prod_1=400115+4.04541E+06*KvKhRatio+1288.82*PERMI_L1-995.149*PERMJ_L2+710587
*Porosity-2.66867E+07*KvKhRatio*KvKhRatio-2.45585*PERMI_L1*PERMI_L1+2.85732*PERMJ_L2*PERMJ_L2
```

Effect Estimation

The Effect Estimation plot showcases the influence of various reservoir parameters on cumulative oil production. Porosity and Kv/Kh ratio demonstrate the most significant impact, contributing 50% and 49% of the effects, respectively. Lesser impacts are observed for parameters such as permeability interactions and individual layer permeabilities. This analysis highlights critical factors for optimization in reservoir performance modelling.

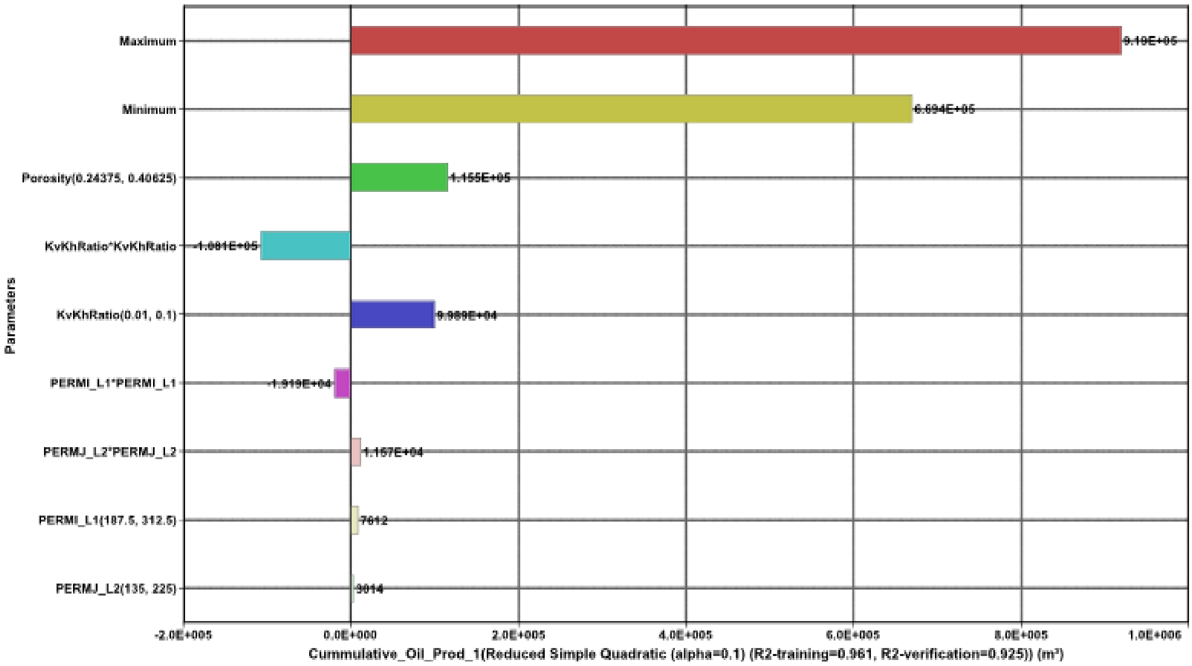

Image: Effect Estimation Plot

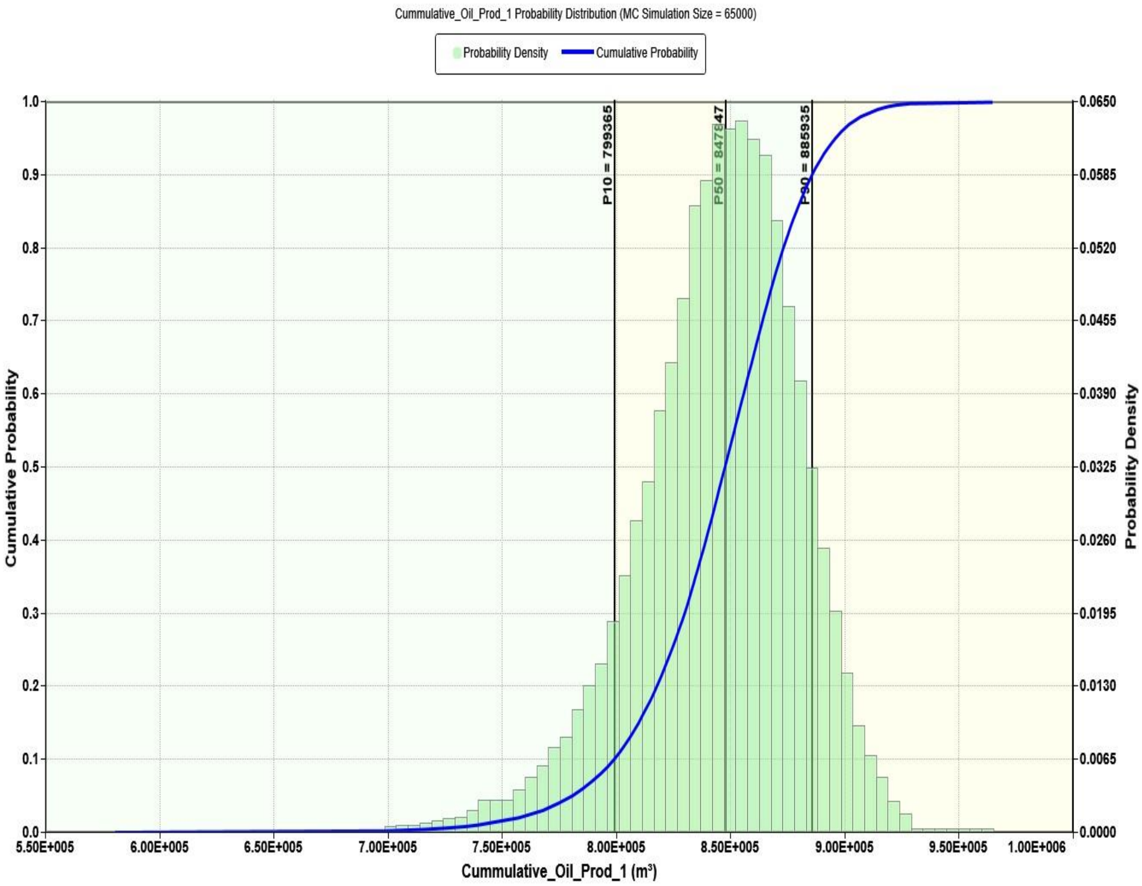

Image: Monte Carlo Simulation

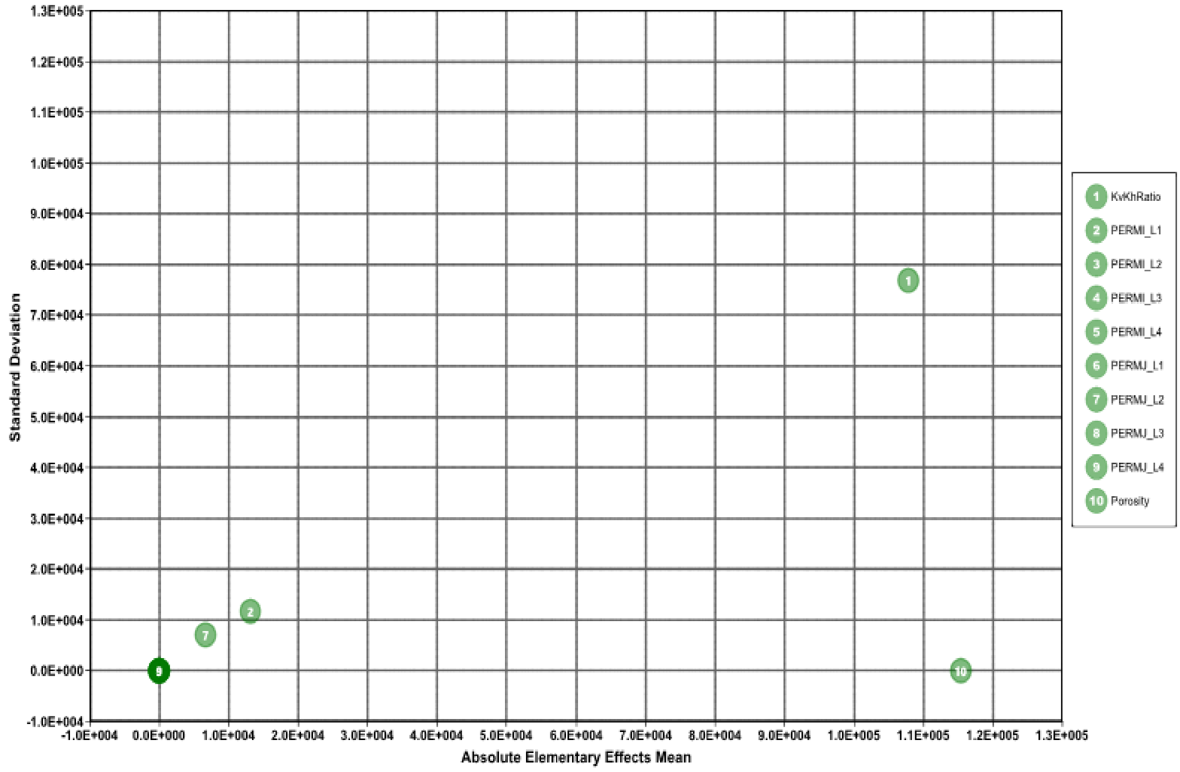

Image: Morris Analysis

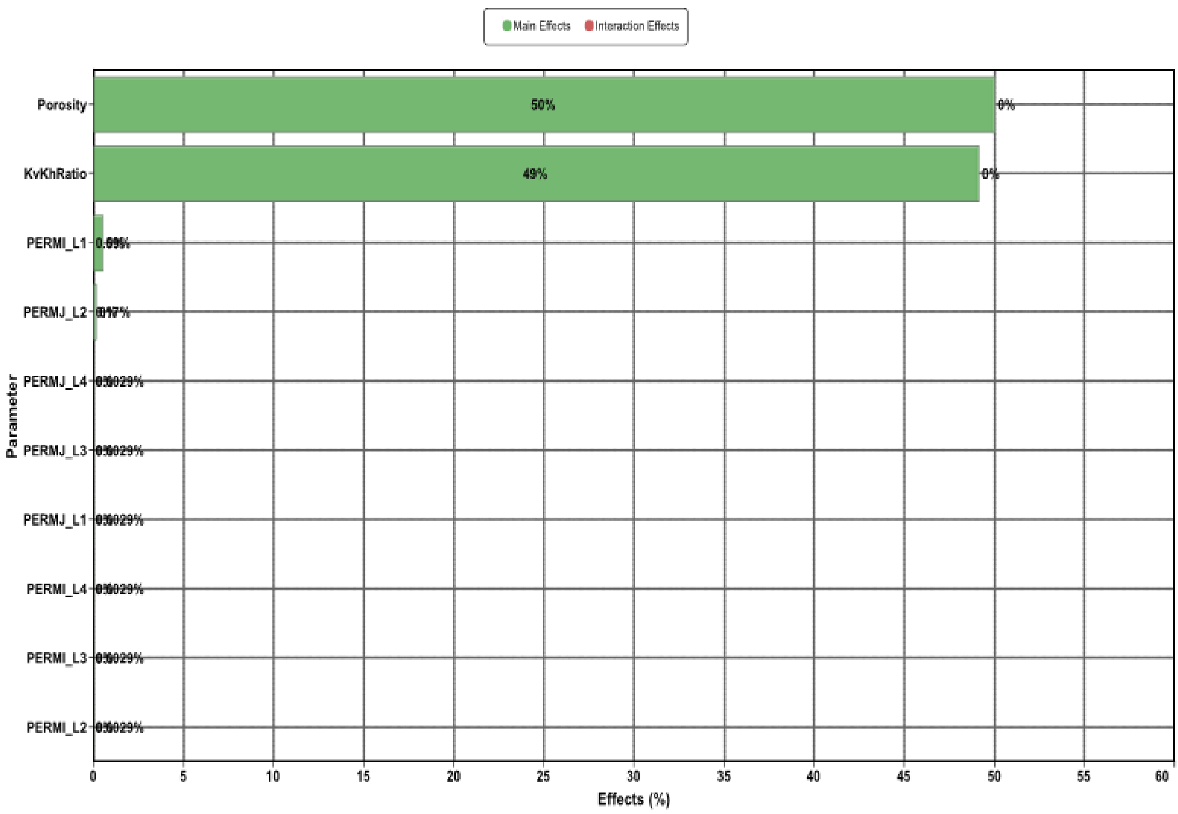

Image: Sobol Analysis

Well-2 Sensitivity Analysis and Results

Key Observations:

- **Effects Estimation:** Porosity has the highest positive effect on cumulative oil production with a value of 1.15×10^5, followed by KvKh Ratio (1.00×10^5). The interaction terms such as $KvKhRatio^2$ (-1.10×10^5) negatively influence production.
- **Monte Carlo and Morris Analysis:** Porosity (115,373.79) and KvKh Ratio (110,000) show the most significant elementary effects, demonstrating their dominance in influencing reservoir behavior.
- **Sobol Analysis:** Porosity and KvKh Ratio together contribute to almost all the main effects (approximately 50% each), while the interaction effects are negligible.

Well-3 Sensitivity Analysis and Results

Key Observations:

- **Effects Estimation:** Like Well-2, Porosity (1.16×10^5) and KvKh Ratio (9.98×10^4) are the most influential. However, the interaction terms (-1.08×10^5 for $KvKhRatio^2$) remain consistent in negatively impacting oil production.
- **Monte Carlo and Morris Analysis:** KvKh Ratio and Porosity stand out as the dominant parameters, with KvKh Ratio showing an elementary effect mean of 95,500, while porosity remains around 115,686.7.
- **Sobol Analysis:** Porosity (50.23%) slightly exceeds the influence of KvKh Ratio (49.01%) in main effects. This well also confirms negligible contributions from other parameters.

Well-4 Sensitivity Analysis and Results

Key Observations:

- **Effects Estimation:** Porosity (1.15×10^5) and KvKh Ratio (9.98×10^4) remain consistent as the leading factors influencing cumulative production. Interaction effects (-1.08×10^5) again negatively impact results.
- **Monte Carlo and Morris Analysis:** Similar trends are observed, with KvKh Ratio (91,200) and Porosity (114,763.94) driving the overall production response.
- **Sobol Analysis:** The main effects of Porosity (49.79%) and KvKh Ratio (49.38%) dominate, with minimal contributions from interaction effects or other parameters.

Results and Discussion

1. Base Case Modelling and Reservoir Performance

The base case provided a comprehensive understanding of the reservoir's baseline performance. The cumulative oil production for the entire field was observed to be around **3,408.8 MSM^3**, with **826.62 MMSM^3 of gas** and **4.52 MSM^3 of water** produced. The field's total hydrocarbon pore volume and total pore volume provided a solid basis for further analysis, ensuring accurate modeling of fluid flow and production forecasts.

The **production constraints** implemented in the base case, such as maintaining bottom-hole pressure above 1,000 kPa and restricting gas-oil ratio to below 3,000 m^3/m^3, successfully controlled excessive gas or water production. These constraints played a vital role in optimizing oil recovery and minimizing risks such as gas breakthrough or water coning.

2. Sensitivity Analysis and Parameter Evaluation

The **sensitivity analysis (SA)** revealed that Porosity and KvKh Ratio were the most influential parameters across all wells. These two parameters contributed the most to variations in cumulative oil production, as highlighted by the Monte Carlo, Morris, and Sobol analyses.

Key Findings:

- **Porosity:** Responsible for approximately **50% of the total effects** in Sobol analysis, Porosity consistently emerged as the dominant factor affecting production. Higher porosity values correlate with increased hydrocarbon storage and flow capacity.
- **KvKh Ratio:** Contributing nearly **49% of total effects**, the KvKh Ratio's influence emphasizes the importance of anisotropy in permeability, which governs vertical fluid flow and sweep efficiency.
- Interaction terms (KvKhRatio^2) negatively impacted oil production, suggesting a non-linear behavior and diminishing returns at higher anisotropy levels.

3. **Well-by-Well Performance** Each well exhibited similar trends in terms of parameter sensitivity:

- **Well-1:** Porosity and KvKh Ratio dominated, with cumulative oil production highly responsive to their changes.
- **Well-2 to Well-4:** These wells confirmed the findings from Well-1, with consistent trends observed in both positive and negative parameter effects. However, slight variations in parameter contributions highlight reservoir heterogeneity and localized variations in permeability and porosity.

Performance Observations:

- Wells targeting **high-permeability zones** achieved better recovery.
- **Cumulative oil production** increased with optimized porosity and KvKh Ratio settings, but excessive anisotropy or high interaction effects negatively impacted production.

4. Proxy Analysis and Objective Functions

The proxy model accurately predicted cumulative oil production, with an **R-squared value of 0.96**, demonstrating excellent model reliability. The equation derived from the proxy analysis effectively quantified parameter contributions and interactions, offering a robust tool for future optimization.

Key insights from the **proxy analysis**:

- **KvKh Ratio** and **Porosity** had the highest coefficients, indicating their dominant influence on oil recovery.
- Interaction effects, while significant, accounted for minor contributions compared to the primary effects of Porosity and KvKh Ratio.

5. **Monte Carlo and Sobol Analysis**

The **Monte Carlo simulation** confirmed Porosity and KvKh Ratio as the most sensitive parameters, with minimal contributions from other parameters. Similarly, **Sobol analysis** validated the findings, showing nearly equal contributions from Porosity and KvKh Ratio to cumulative oil production, with negligible interaction effects.

Conclusions

1. **Base Case Summary:** The base case modeling established a comprehensive understanding of the reservoir's performance under initial conditions.

- **Key production outputs:**
    - Cumulative oil production: **3,408.8 MSM^3**
    - Gas production: **826.62 MMSM^3**
    - Water production: **4.52 MSM^3**
- Operational constraints, such as maintaining a bottom-hole pressure of 1,000 kPa and limiting the gas-oil ratio to 3,000 m^3/m^3, successfully prevented operational risks like gas breakthrough and water coning.

The base case set a solid foundation for sensitivity analysis by establishing initial fluid distribution, well performance, and reservoir pressure trends.

2. **Sensitivity Analysis (SA) Summary:** The **SA studies** identified **Porosity** and **KvKh Ratio** as the most significant parameters affecting oil production:

    - **Porosity** contributed **50% of the total effects** and was directly proportional to oil recovery due to its influence on hydrocarbon storage and flow capacity.

    - **KvKh Ratio** contributed **49%**, highlighting the importance of permeability anisotropy in vertical fluid movement and sweep efficiency.

    - **Interaction effects** (e.g., KvKhRatio^2) revealed diminishing returns at higher anisotropy levels, indicating a non-linear impact on recovery.

- **Well-specific findings:**

- Consistent trends were observed across all wells (Well-1 to Well-4), with minor variations due to reservoir heterogeneity.
- Wells targeting **high-permeability zones** achieved optimal performance, emphasizing the importance of well placement strategies.

3. **Proxy and Statistical Analysis:** The **proxy model** demonstrated excellent predictive accuracy, with an **R-squared value of 0.96**, effectively quantifying parameter contributions and interactions.

- **Key parameter effects:**
  - Positive contributions from Porosity and KvKh Ratio.
  - Negative contributions from interaction terms ($KvKhRatio^2$), underscoring the non-linear behavior of reservoir performance.

4. **Key Findings**

- **Monte Carlo and Sobol Analysis:**
  - Reinforced the dominance of Porosity and KvKh Ratio, with negligible contributions from other parameters.
  - Confirmed the minimal interaction effects, validating the robustness of individual parameter optimization.
- **Enhanced Production Strategies:**
  - Targeting zones with optimal Porosity and KvKh Ratio led to improved cumulative oil recovery.
  - The findings offer valuable insights for refining well placement and reservoir management strategies.

5. **Major Conclusions**

1. **Porosity and KvKh Ratio are the most critical parameters** influencing oil recovery in the reservoir.
2. **Sensitivity analysis and proxy modeling** provide robust tools for identifying and optimizing key reservoir properties, leading to improved decision-making and resource utilization.
3. Interaction effects play a secondary role compared to primary parameter effects, indicating that straightforward optimization of key parameters is sufficient for enhancing production.
4. Sustainable reservoir management can be achieved by balancing operational constraints with optimized production strategies, ensuring long-term recovery goals.

Group Reflection and Acknowledgment

Group Reflection

This project has been a collective effort, showcasing excellent teamwork, collaboration, and dedication from all members. Each member played a vital role in ensuring the success of the project, from data analysis to simulation, sensitivity studies, and reporting. Regular discussions and brainstorming sessions fostered a positive environment, allowing us to overcome challenges together and bring out the best in each other.

Through this project, we not only deepened our technical understanding of reservoir modeling and performance optimization but also honed essential skills such as communication, problem-solving, and time management. Working together strengthened our ability to share ideas, respect diverse opinions, and leverage each other's strengths.

Vote of Thanks

We would like to extend our heartfelt gratitude to everyone who contributed to the successful completion of this project:

- **Our mentors and supervisors,** for their guidance, expertise, and constant encouragement throughout the process.
- **Our institution,** for providing the tools, resources, and support necessary to carry out this project effectively.
- **Our peers and colleagues,** for their constructive feedback and collaboration.

Lastly, a special thank you to our team members for their hard work, persistence, and enthusiasm. This project stands as a testament to what we can achieve when we work together with a shared vision and dedication. Thank you all!

Team (Exxon Mobil)

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Abhinav Medithi,

Sumanth Kumar Chadipiralla.

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