Revitalizing a Mature Oil Field in Libya's Sirte Basin: An Integrated Reservoir Simulation and Economic Optimization Study

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Abstract

The X oil field in Libya's Sirte Basin, with proven reserves exceeding 5 billion barrels in the basin, is experiencing a significant production decline due to insufficient natural aquifer support. This study presents an integrated reservoir simulation and economic optimization approach to revitalize this mature asset. Using the ECLIPSE 100 simulator, we developed a dynamic 3D black-oil model that accurately captured the field's weak aquifer drive through rigorous history matching (1999–present). The model evaluated multiple development scenarios, including hydraulic fracturing and infill drilling with vertical and horizontal wells. Results indicate that horizontal infill drilling in the structurally advantageous northern sector provided the best single-technique recovery (13.40%, 28.54 MMSTB). However, an integrated strategy combining northern horizontal wells with southern vertical exploratory drilling achieved superior outcomes: recovery factor of 17.65% and cumulative production of 37.60 MMSTB—a six-fold increase over the base "do-nothing" case (2.81%, 5.98 MMSTB). Economic evaluation, including detailed net present value (NPV) and sensitivity analysis, confirmed the financial viability of this optimal approach, generating an NPV of $671.84 million and a net cash flow of $2,294.63 million at a 10% discount rate. Sensitivity analysis demonstrated resilience to oil price fluctuations and discount rate variations. This study demonstrates that data-driven integrated modeling can unlock substantial unrealized potential in mature fields, providing a replicable framework for similar assets in the Sirte Basin and analogous carbonate reservoirs worldwide.

Keywords: Mature field redevelopment, Reservoir simulation, Horizontal infill drilling, Economic optimization, Sirte Basin, Weak aquifer drive

المستخلص

يُعاني حقل النفط X في حوض سرت بليبيا، الذي تتجاوز الاحتياطيات المؤكدة في الحوض 5 مليارات برميل، من انخفاض ملحوظ في الإنتاج نتيجة ضعف الدعم الطبيعي من المكمن المائي. تقدم هذه الدراسة منهجية متكاملة لمحاكاة المكمن والتحسين الاقتصادي بهدف إعادة تنشيط هذا الحقل الناضج. وباستخدام برنامج المحاكاة ECLIPSE 100، تم تطوير نموذج ديناميكي ثلاثي الأبعاد من نوع Black–Oil، نجح في تمثيل آلية الدفع بالمكمن المائي الضعيف في الحقل بدقة، وذلك من خلال إجراء مطابقة تاريخية صارمة للفترة من عام 1999 وحتى الوقت الحاضر.

قيّم النموذج عدة سيناريوهات لتطوير الحقل، شملت التكسير الهيدروليكي وحفر الآبار التعويضية باستخدام آبار رأسية وأفقية. وأظهرت النتائج أن حفر الآبار الأفقية التعويضية في القطاع الشمالي ذي المزايا التركيبية حقق أفضل معدل استخلاص عند استخدام تقنية منفردة، حيث بلغ 13.40%، بإنتاج تراكمي قدره 28.54 مليون برميل قياسي.(MMSTB)

ومع ذلك، حققت الاستراتيجية المتكاملة التي تجمع بين الآبار الأفقية في القطاع الشمالي وحفر آبار رأسية استكشافية في القطاع الجنوبي نتائج أفضل، حيث بلغ معامل الاستخلاص 17.65 %والإنتاج التراكمي 37.60 مليون برميل قياسي (MMSTB)، أي ما يعادل زيادة تقارب ستة أضعاف مقارنة بحالة الأساس "عدم القيام بأي إجراء(Do–Nothing) "، التي حققت معامل استخلاص قدره 2.81% وإنتاجًا تراكميًا بلغ 5.98 مليون برميل قياسي.

كما أكد التقييم الاقتصادي، الذي شمل حسابًا تفصيليًا لصافي القيمة الحالية (NPV) وتحليل الحساسية، الجدوى المالية لهذا النهج الأمثل؛ إذ حقق صافي قيمة حالية قدرها 671.84 مليون دولار وصافي تدفق نقدي بلغ 2,294.63 مليون دولار عند معدل خصم قدره 10%. وأظهر تحليل الحساسية قدرة المشروع على الصمود أمام التغيرات في أسعار النفط ومعدلات الخصم.

وتوضح هذه الدراسة أن النمذجة المتكاملة القائمة على البيانات يمكن أن تسهم في استغلال إمكانات كبيرة غير مستثمرة في الحقول الناضجة، كما توفر إطارًا قابلًا للتطبيق والتكرار على أصول مماثلة في حوض سرت وفي المكامن الكربوناتية المماثلة حول العالم.

الكلمات المفتاحية :إعادة تطوير الحقول الناضجة، محاكاة المكامن، حفر الآبار الأفقية التعويضية، التحسين الاقتصادي، حوض سرت، الدفع بالمكمن المائي الضعيف.

INTRODUCTION

The global energy landscape remains heavily reliant on hydrocarbon resources, with mature oil fields accounting for approximately 70% of the world's current production [1, 2]. Efficient reservoir development and management are critical to maximizing hydrocarbon recovery and ensuring the economic viability of these assets. Libya's Sirte Basin, containing proven reserves exceeding 5 billion barrels [3], represents a significant component of global hydrocarbon resources. However, many fields in this basin, including the X Field, face declining production due to natural depletion and insufficient aquifer support, highlighting the urgent need for optimized redevelopment strategies.

Reservoir management has evolved significantly with advancements in modeling capabilities [4]. Key themes relevant to this study include: 1) Integrated reservoir characterization, combining static geological data with dynamic production information [5]; 2) Reservoir simulation fundamentals, where numerical models predict reservoir behavior under various scenarios [6]; 3) Advanced drilling technologies, including horizontal and multilateral wells that improve reservoir contact and drainage efficiency [7]; 4) Enhanced oil recovery methods, ranging from infill drilling to more complex chemical and thermal processes [8]; and 5) Economic evaluation frameworks that assess project viability through metrics like net present value (NPV) and internal rate of return (IRR) [9].

The X Field, discovered in 1961 but only producing since 1999, currently yields approximately 500 barrels per day from five wells, with recovery estimated at only 2.81% of original oil in place. This underperformance, coupled with the basin's substantial remaining potential, makes it an ideal candidate for comprehensive redevelopment planning.

While previous studies have addressed geological aspects of Sirte Basin reservoirs [10], few have presented integrated simulation-economic workflows tailored specifically to mature fields with weak aquifer support. Asheibi and Shams [11] examined reservoir geometry and depositional architecture but did not incorporate dynamic simulation or economic optimization. Recent advances in reservoir simulation [12, 13] and drilling technology [14] provide new opportunities for revitalizing such mature assets.

This study addresses this gap by developing a full-field dynamic model to evaluate multiple development scenarios for X Field, including base depletion, infill drilling (vertical and horizontal), hydraulic fracturing, and combined strategies. Each scenario is assessed through both technical metrics (recovery factor, cumulative production) and economic indicators (NPV, payout time). The novelty of this work lies in its integrated approach—combining detailed geological modeling, rigorous history matching, multi-scenario forecasting, and comprehensive economic analysis specifically designed for weak-aquifer-driven mature fields. Additionally, we contextualize this hydrocarbon-focused study within the broader energy transition, noting the growing importance of alternative energy materials while addressing the immediate practical need to optimize existing petroleum assets.

The primary objectives are: (1) to develop a reliable dynamic model through rigorous history matching; (2) to evaluate various development scenarios both technically and economically; (3) to identify the optimal strategy for maximizing recovery while ensuring profitability; and (4) to provide a replicable framework for similar mature fields. The following sections detail the methodology, results, and implications of this comprehensive study.

1. METHODOLOGY

2. 2.1 Data Acquisition and Model Setup

The dataset for this study was provided by Mabruk Oil Company (MOC), comprising comprehensive geological and engineering information required for reservoir modeling and simulation. The data structure and simulation workflow were initially validated to ensure consistency and reliability. Data components included:

- Well Logs: Complete wireline logs from all five wells (gamma-ray, neutron, resistivity, density) used for petrophysical analysis to determine porosity, water saturation, and net pay.
- Core Data: Laboratory measurements from two wells providing precise porosity, permeability, and rock-type data for log calibration and rock typing.
- Technical Reports: Internal documents detailing geological context, production history, and previous reservoir studies.
- Production Data: Historical records (1999–present) of oil, gas, and water rates, along with flowing and static bottom-hole pressures for history matching.
- Seismic Data: 3D seismic volumes used to interpret key horizons, faults, and structural framework.

The simulation grid was constructed with dimensions 50 × 60 × 15 layers, with cell sizes ranging from 50×50 m to 100×100 m horizontally and 1–5 m vertically, based on flow unit delineation. Porosity was upscaled using arithmetic averaging, while permeability employed harmonic averaging to preserve flow characteristics.

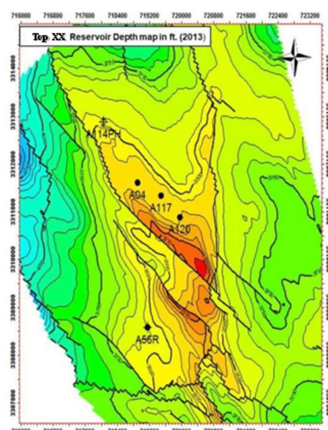

Fig 1. Map indicating well locations producing

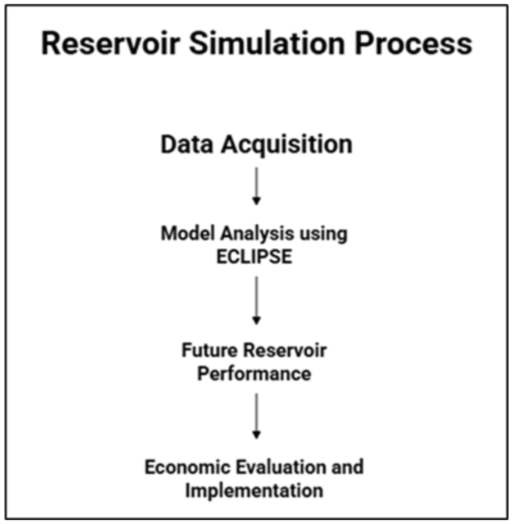

Fig 2. Methodology workflow

2.2 Model Construction and History Matching

Reservoir simulation was performed using the ECLIPSE 100 Black-Oil simulator. The static geological model, integrating seismic interpretation, well logs, and core data, was converted to a dynamic simulation grid with defined rock properties and fluid interactions.

Aquifer Modeling: A Carter-Tracy analytical aquifer was attached to the reservoir model, with parameters calibrated to match observed pressure decline. Aquifer size was estimated at 3× reservoir volume with moderate connectivity based on material balance analysis. Sensitivity analysis showed that recovery factors vary by ±15% with aquifer strength changes.

History Matching: The dynamic model was calibrated using production data from 1999 to present. Key parameters adjusted included permeability distribution (via multiplier fields), relative permeability curves, and aquifer strength. Match quality was quantified using normalized root mean square error (NRMSE), achieving values below 5% for oil rates and 8% for bottom-hole pressures. The successful history match (Fig. 2) validated the model's predictive capability for scenario forecasting.

Equations: The model solved standard black-oil equations:

$$\frac{\partial}{\partial t}(\phi\,\rho_\alpha S_\alpha) = \nabla\cdot\left(\rho_\alpha \frac{k\,k_{r\alpha}}{\mu_\alpha}\nabla\Phi_\alpha\right) + q_\alpha$$

Where:

- α — phase (oil, water, or gas)
- ϕ — porosity
- ρ_α — phase density
- S_α — phase saturation
- k — absolute permeability
- $k_{r\alpha}$ — relative permeability of the phase
- μ_α — phase viscosity
- Φ_α — phase potential (typically $\Phi_\alpha = p_\alpha + \rho_\alpha g z$)
- q_α — source/sink term (well terms)

2.3 Development Scenarios

The base case ("do-nothing") projected field performance under current operations. Multiple development scenarios were then simulated over a 34-year forecast period (to 2060):

1. **Infill Drilling:**
   - Case 1-1: Vertical infill drilling (4 new wells)
   - Case 1-2: Horizontal infill drilling (3 new wells, 1000-1500 ft laterals)
   - Case 1-3: Combined vertical and horizontal drilling
2. **Stimulation:**
   - Case 2-1: Hydraulic fracturing in existing wells (modeled with local grid refinement, 150 ft half-length, 3000 md-ft conductivity)
3. **Exploration & Development:**
   - Case 3-1: Southern area vertical development (2 exploratory wells)
4. **Integrated Optimum Case:**
   - Combined Case 1-2 (northern horizontal) and Case 3-1 (southern vertical)

Well placements were geologically justified based on structural position, facies distribution, and distance to oil-water contact (Fig. 5). Operational constraints included minimum bottom-hole pressure (1500 psi) and maximum water cut (95%).

2.4 Economic Evaluation

Economic viability was assessed using standard petroleum economics. Key assumptions:

- Oil price: Base case \$60/bbl, with sensitivity at \$40, \$60, \$80/bbl
- Discount rates: 5%, 10%, 15%, 20%, 25%
- CAPEX: Drilling (\$5M vertical, \$8M horizontal), completion (\$2M), fracturing (\$1.5M per well)
- OPEX: \$15/bbl fixed, \$5/bbl variable

Economic metrics calculated:

- Net Present Value (NPV): Discounted cash flows
- Net Cash Flow (NCF): Undiscounted cash flows
- Cumulative Free Cash Flow (CFCF): Cumulative undiscounted cash flow
- Profitability Index Ratio (PIR): NPV per unit investment
- Maximum Exposure: Peak negative cash flow
- Payout Time (POT): Time to recover initial investment

Sensitivity analysis examined the impact of oil price and discount rate variations on NPV, with tornado charts quantifying parameter influence (Figs. 16-17).

RESULTS AND DISCUSSION

The outcomes of the simulation show a clear comparison of the technical and economic performance of the various development options vs the baseline. The analysis is designed so that each scenario's technical outcomes are presented first, followed by a full explanation of the economic assessment.

3.1 Technical Performance

Base Case: The "do-nothing" scenario yielded only 2.81% recovery (5.98 MMSTB), confirming rapid decline due to weak aquifer support and demonstrating the urgent need for intervention.

Infill Drilling Scenarios:

- **Case 1-1 (Vertical):** 10.46% recovery, 22.28 MMSTB. Improved drainage but limited by water coning and localized sweep.
- **Case 1-2 (Horizontal):** 13.40% recovery, 28.54 MMSTB. Superior sweep efficiency and delayed water breakthrough due to increased reservoir contact.
- **Case 1-3 (Combined):** 12.27% recovery, 26.15 MMSTB. Incremental gain over vertical-only, but less efficient than horizontal-only configuration.

Stimulation and Exploration:

- **Case 2-1 (Hydraulic Fracturing):** 12.24% recovery, 26.06 MMSTB. Short-term productivity boost, but limited long-term recovery enhancement compared to new drainage points.
- **Case 3-1 (Southern Vertical Development):** 12.24% recovery, 26.06 MMSTB. Confirmed southern potential but dependent on local reservoir quality variations.

Optimal Integrated Case: Combining northern horizontal infill drilling with southern vertical development achieved 17.65% recovery (37.60 MMSTB)—a six-fold improvement over base case. This strategy effectively drained both structurally high northern areas (via horizontal wells) and previously untapped southern volumes (via vertical wells), representing the most comprehensive reservoir management approach.

Technical Feasibility: All proposed scenarios are operationally feasible given current industry capabilities in the Sirte Basin. Horizontal drilling and hydraulic fracturing are established technologies in the region, though the optimal case requires careful sequencing and simultaneous operations management. The geological rationale for well placement is supported by structural maps showing higher permeability channels in the northern sector oriented parallel to proposed horizontal well trajectories.

Aquifer Sensitivity: Recovery factors varied by ±15% with aquifer strength changes, highlighting the importance of this parameter in forecasting. However, even with pessimistic aquifer assumptions, the optimal case consistently outperformed all alternatives.

Figures 3-14 illustrate the field's performance across all scenarios, showing cumulative production, production rates, and pressure dynamics. The production profiles demonstrate clear differentiation between strategies, with horizontal wells showing higher initial rates and more sustained production (Figs. 7-8).

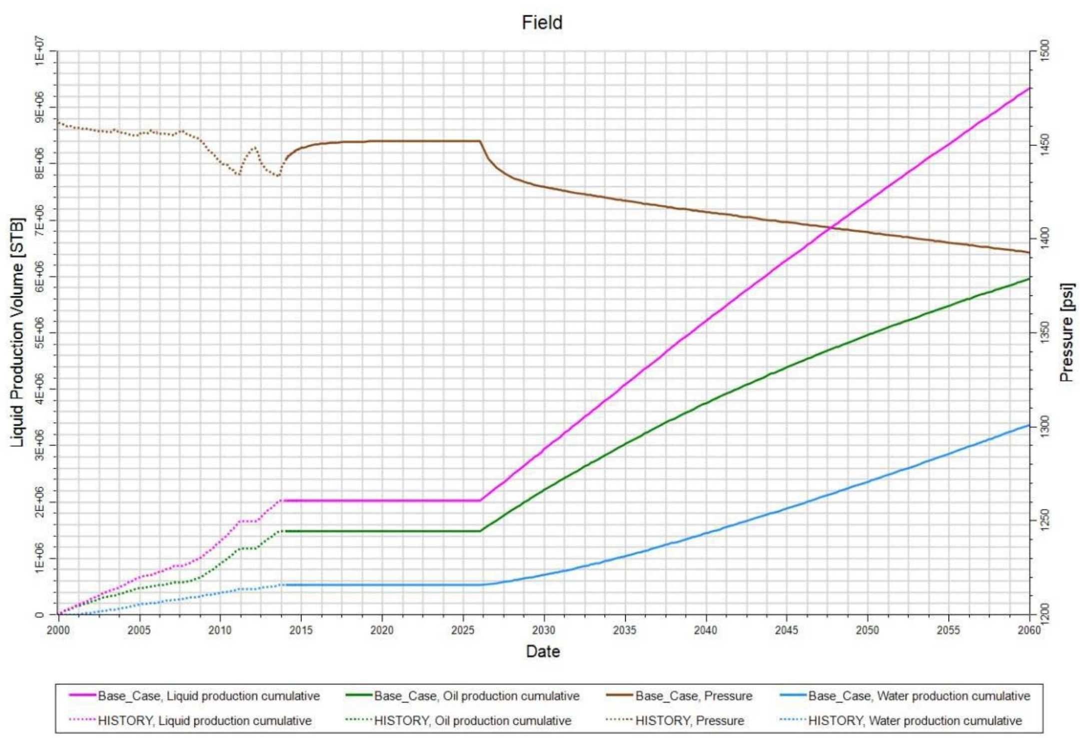

Fig. 3 Profile of reservoir output performance under natural depletion conditions

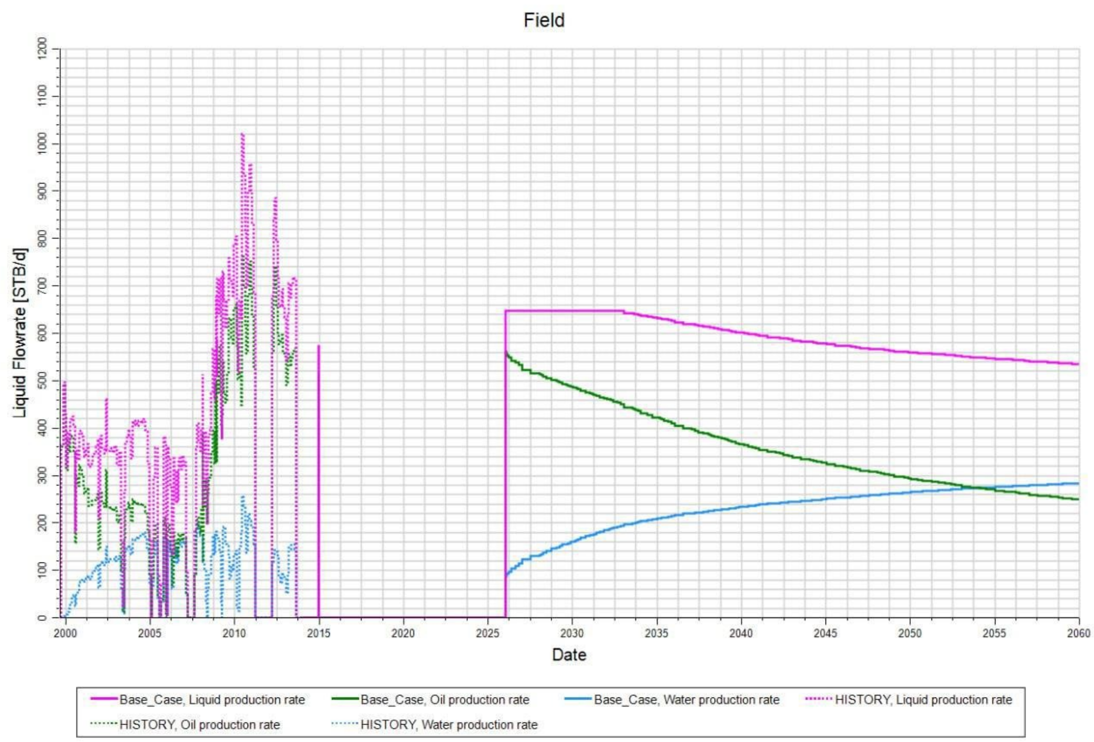

Fig. 4 Field production rate profiles (Historical and prediction)

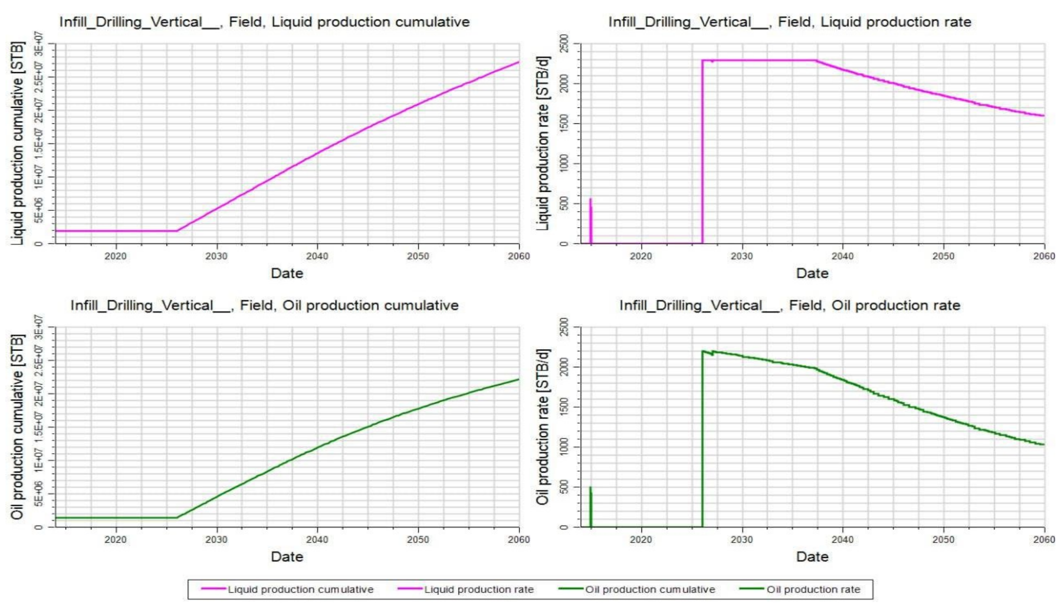

Fig. 5 Cumulative production and production rate profile for vertical wells

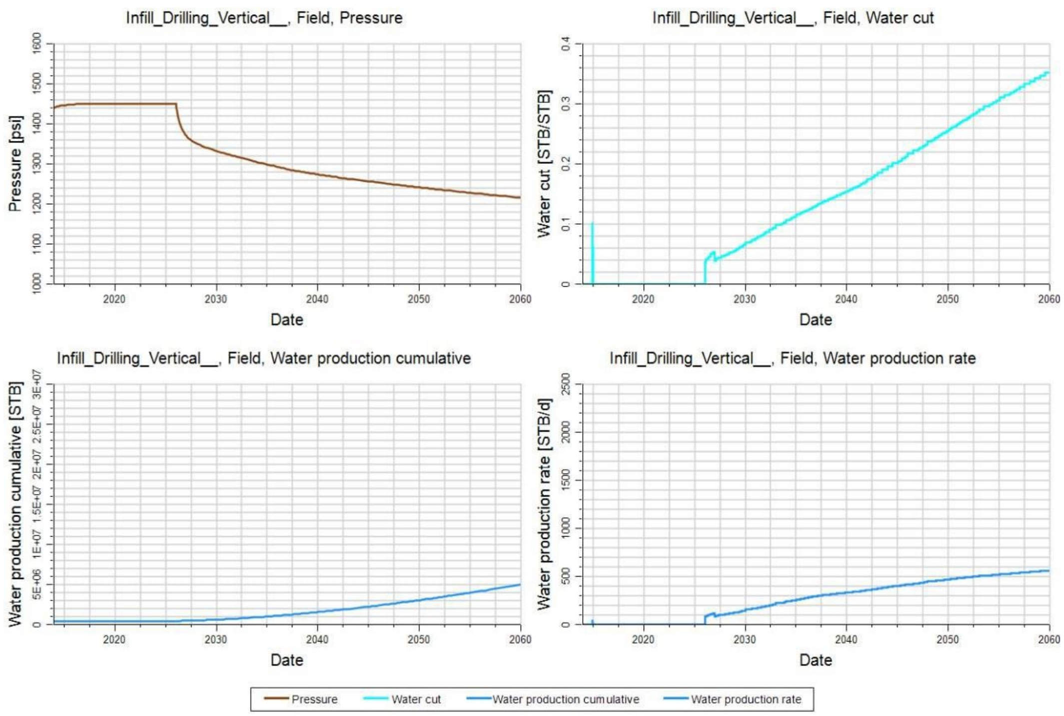

Fig. 6 Field performance evaluation for vertical wells

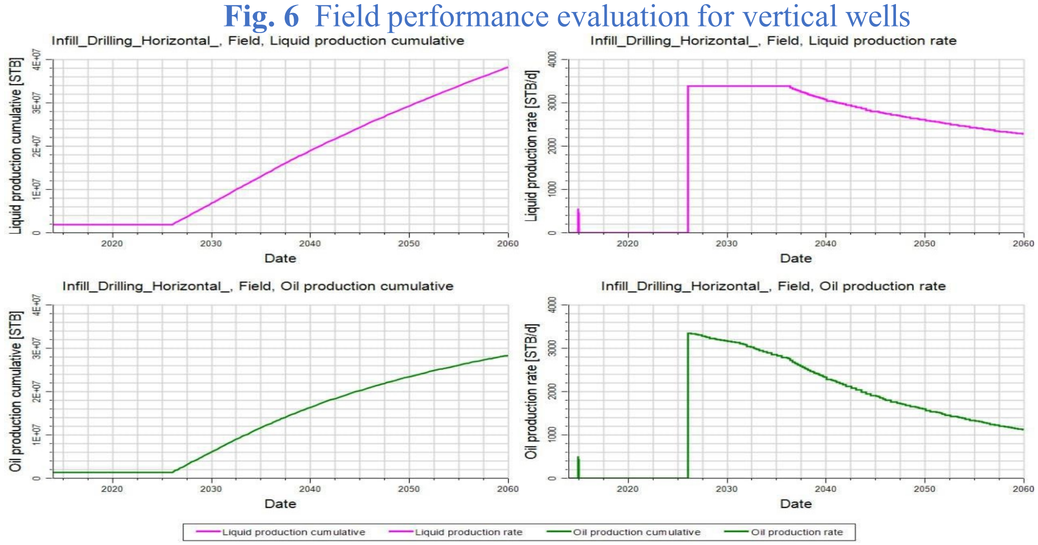

Fig. 7 Cumulative production and production rate profile for horizontal wells

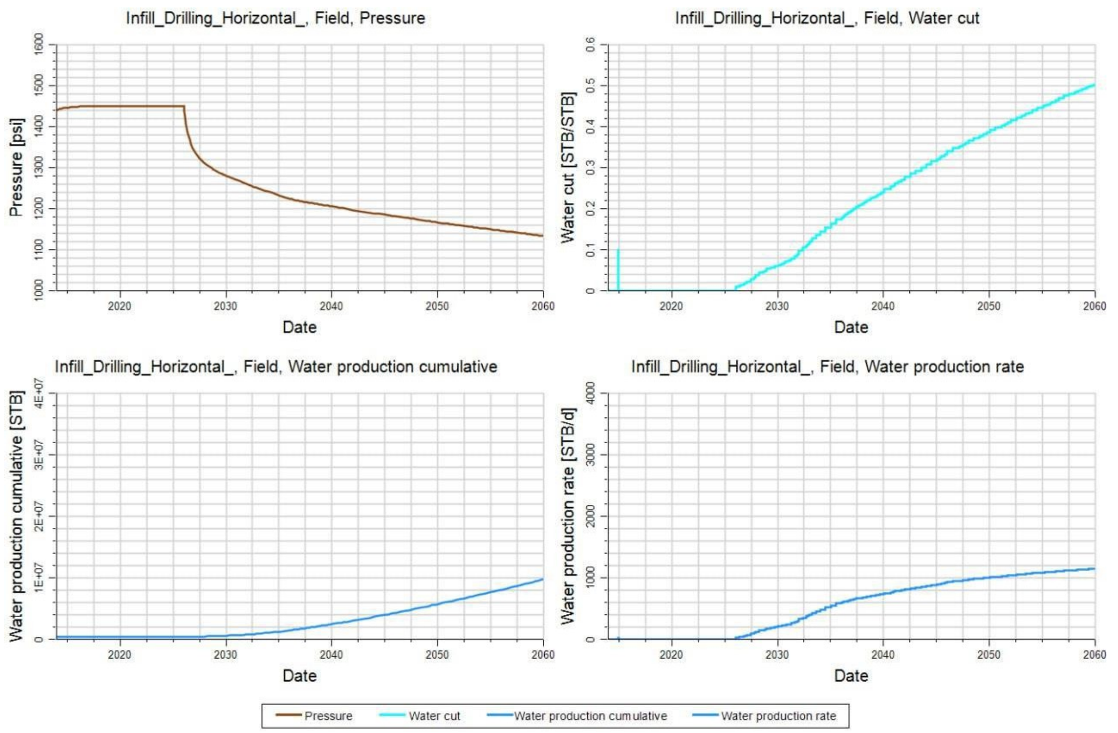

Fig. 8 Field performance evaluation for horizontal wells

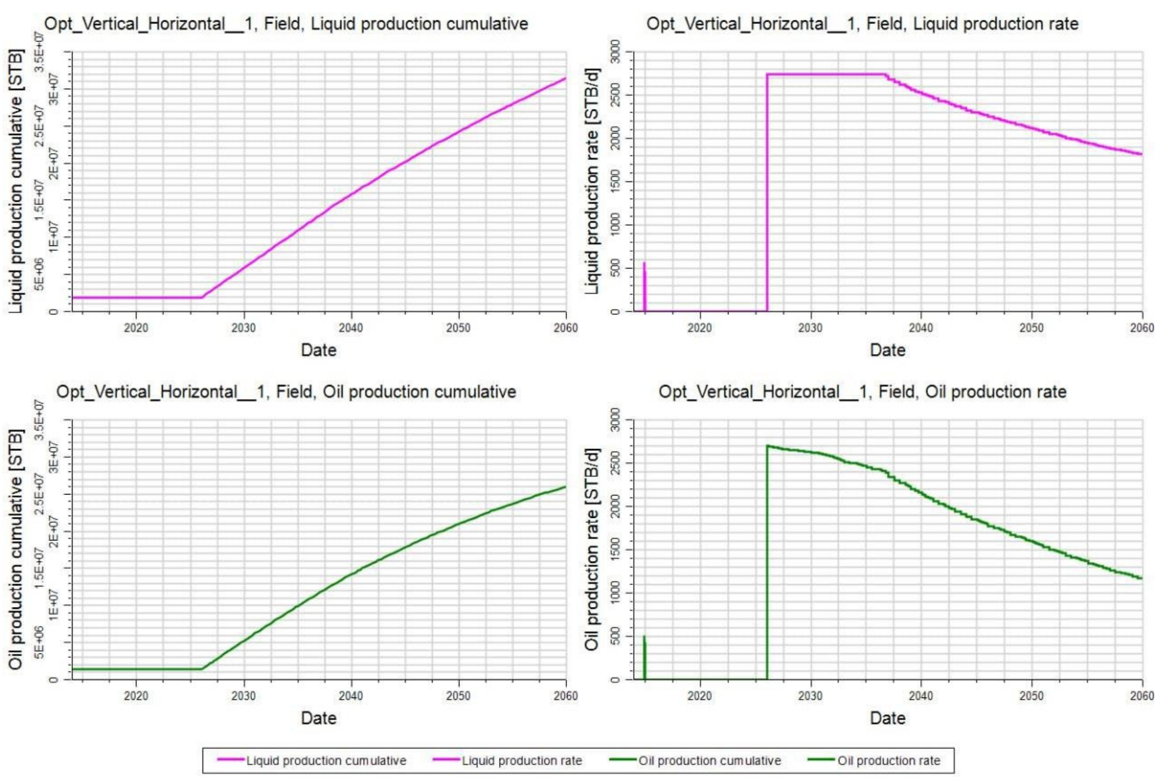

Fig. 9 Cumulative production and production rate profile of case 1-3

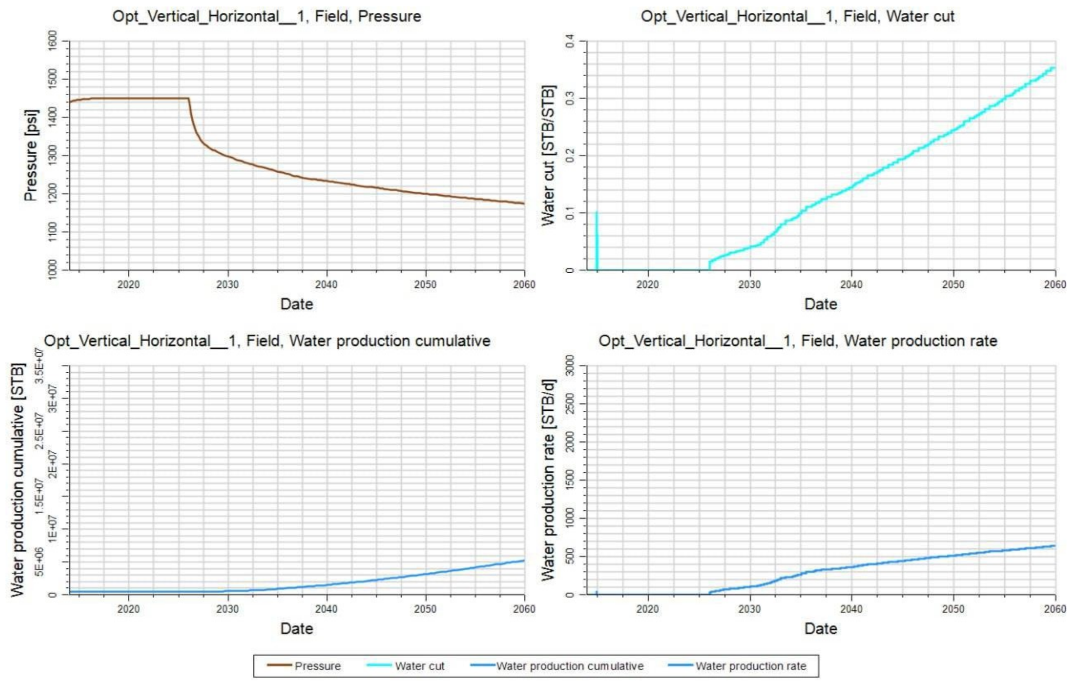

Fig. 10 Field performance evaluation for case 1-3

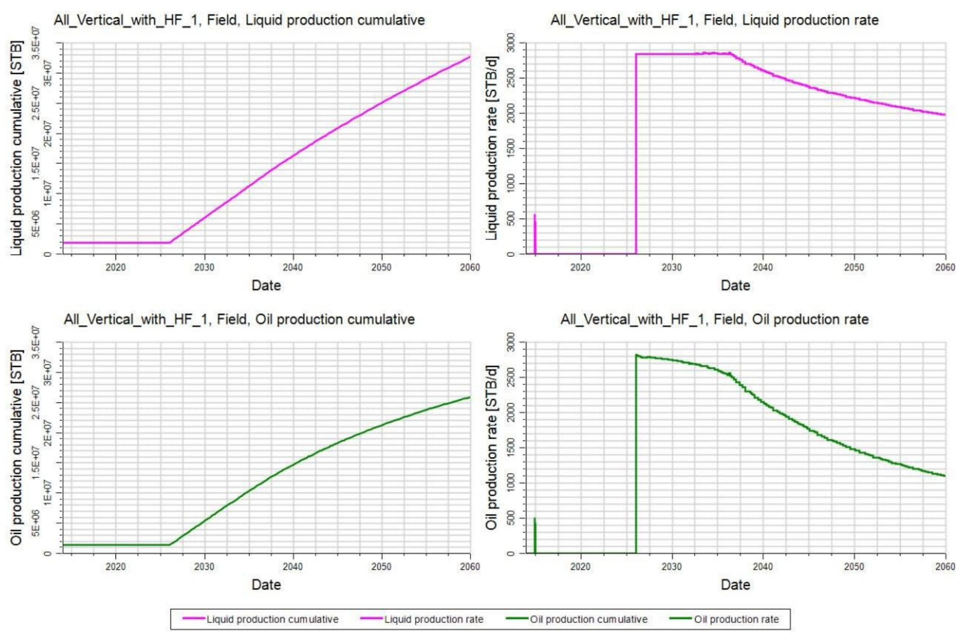

Fig. 11 cumulative production and production rate profile of case 2-1

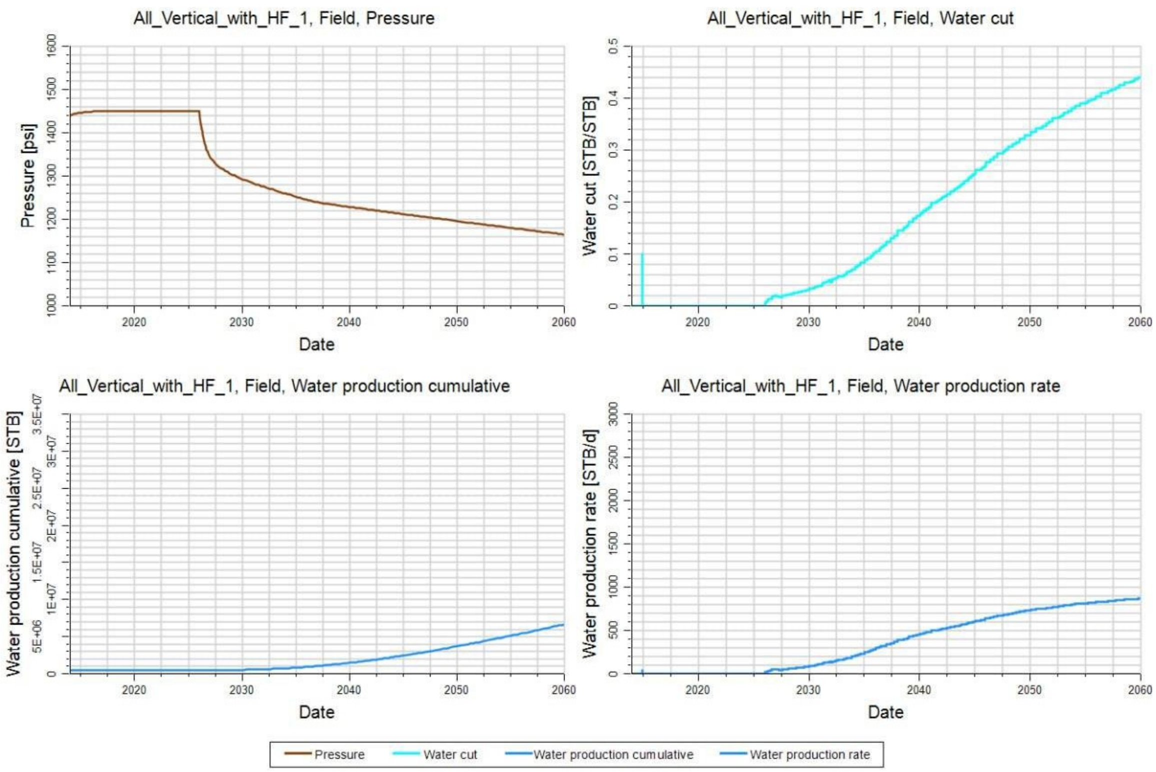

Fig. 12 Field performance evaluation of case 2-1

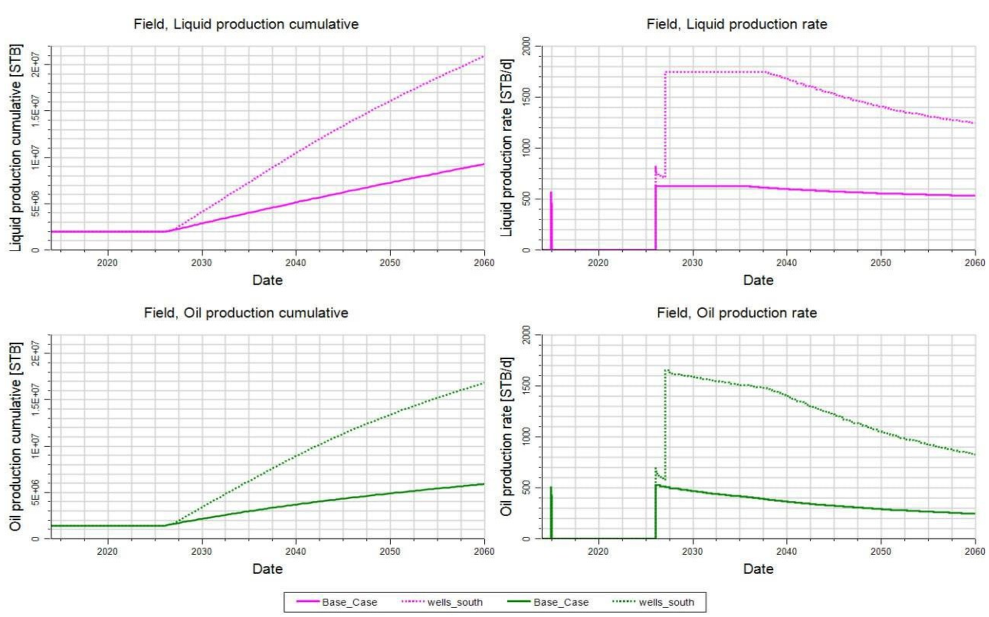

Fig. 13 Cumulative production and production rate profile of case 3-1

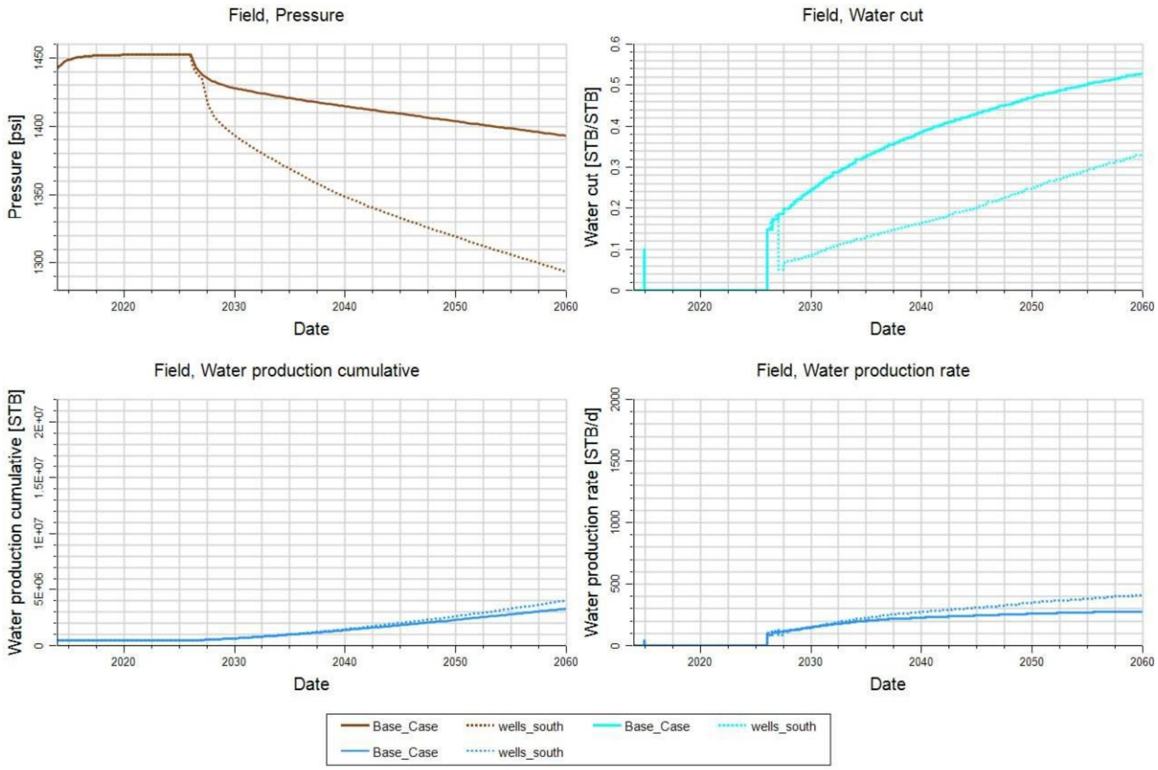

Fig. 14 field performance evaluation: pressure, for the case 3-1

3.2Economic Evaluation

- **Economic Performance at Base Conditions ($60/bbl, 10% discount):**

The economic analysis revealed substantial differences between scenarios (Table 1):

Table 1: Economic Indicators for All Scenarios ($60/bbl, 10% discount rate

Profit Indicators	Base Case	Case 1-1	Case 1-2	Case 1-3	Case 2-1	Case 3-1
CFCF ($MM)	341.49	1194.51	1633.67	1480.95	1446.78	816.32
NPV ($MM)	97.87	314.46	496.07	407.36	412.17	197.65
Max Exposure ($MM)	10.59	40.04	59.51	50.02	52.68	27.89
PIR ($/$)	9.24	26.656	47.014	34.194	27.395	29.37

• **Optimal Case Performance:**
The integrated optimal case generated:

- Cumulative Free Cash Flow (CFCF): $2,294.63 MM
- NPV @10%: $671.84 MM
- Maximum Exposure: $85.23 MM
- Payout Time: 4.2 years

• **Sensitivity Analysis:**
A comprehensive sensitivity analysis assessed the optimal development plan's resilience to market volatility (Table 2):

Table 2: NPV Sensitivity to Oil Price and Discount Rate for Optimal Case ($MM)

Oil Price ($/bbl)	NPV @ 5% ($MM)	NPV @ 10% ($MM)	NPV @ 15% ($MM)	NPV @ 20% ($MM)	NPV @ 25% ($MM)
10	67.08	19.68	-0.58	-10.39	-15.54
20	278.85	150.11	90.92	59.33	40.54
40	702.39	410.97	273.91	198.77	152.69
60	1125.93	671.84	465.91	338.21	264.85
80	1549.47	932.70	639.90	477.66	377

.Key findings from sensitivity analysis:

- Oil price variation ($40-$80/bbl) caused NPV changes of ±40%
- Discount rate variation (5-25%) resulted in NPV reductions up to 75%
- Break-even oil price at 25% discount: $12.77/bbl
- At a $10/bbl oil price, the rate of return (ROR) is 14.97%

3. CONCLUSIONS

This study developed and applied an integrated reservoir simulation-economic workflow to optimize development of the mature X Field in Libya's Sirte Basin. The comprehensive analysis leads to the following conclusions:

1. Integrated Modeling Value: The combined geological, dynamic, and economic approach successfully identified optimal development strategies that balance technical recovery with financial returns, providing a replicable framework for similar mature fields.

2. Base Case Limitations: Without intervention, the field would recover only 2.81% of the original oil in place due to weak aquifer support, confirming the critical need for redevelopment planning.

3. Technical Superiority of Horizontal Wells: Horizontal infill drilling in the northern sector provided the best single-technique recovery (13.40%), outperforming vertical wells (10.46%) and hydraulic fracturing (12.24%) due to improved reservoir contact and sweep efficiency.

4. Optimal Integrated Strategy: Combining northern horizontal development with southern vertical exploratory drilling achieved maximum recovery (17.65%, 37.60 MMSTB) through comprehensive reservoir drainage, representing a six-fold improvement over the base case.

5. Economic Viability: The optimal strategy generates an NPV of $671.84 million at 10% discount rate, demonstrating strong profitability with a payout time of 4.2 years and an acceptable risk profile.

6. Resilience to Market Conditions: Sensitivity analysis confirms the plan's robustness across a range of oil prices (break-even at $12.77/bbl for 25% discount rate) and discount rates, indicating strong economic resilience.

8-RECOMMENDATION

Immediate implementation of the integrated development strategy is recommended to realize the field's substantial untapped potential. Further data acquisition, particularly pressure transient analysis and updated seismic, would reduce uncertainties and potentially identify additional opportunities. This workflow provides a replicable template for similar mature fields in the Sirte Basin and analogous settings worldwide, contributing to more sustainable hydrocarbon recovery during the energy transition.

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Conflicts of Interest

The authors declare no conflicts of interest.

ABBREVIATIONS

MMSTB = Million Stock Tank Barrels

NPV = Net Present Value

NCF = Net Cash Flow

CFCF = Cumulative Free Cash Flow

B/D = Barrels Per Day

EIA = Energy Information Administration

POT = Payout Time

MOC = Mabruk Oil Company

EOR = Enhanced Oil Recovery

PIR = Profitability Index Ratio

CAPEX = Capital Expenditures

OPEX = Operating Expenses

TVO = Temporal Value of Money

IRR = Internal Rate of Return

ROR = Rate of Return References

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