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Optimization of Gas Condensate Production Performance in Bahr Essalam Field, Libya

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ABSTRACT

This study investigates production optimization strategies for gas condensate reservoirs, with a focus on the Bahr Essalam Field located in the NC41 Concession of the Sabratah Offshore Basin, Northwest Libya. Gas condensate reservoirs present significant production challenges due to pressure depletion, which can reduce well productivity, gas deliverability, and overall recovery efficiency. Effective pressure management is therefore essential to sustain reservoir performance and enhance hydrocarbon recovery. The objective of this work is to optimize gas production from the central wells in Structure "C" of the Bahr Essalam Field, one of the largest offshore gas-producing fields in the region, extending across Libyan and Tunisian offshore waters. Field data provided by Mellitah Oil & Gas Company were analyzed using Flow-After-Flow testing techniques. The methodology integrates Excel-based Flow-After-Flow analysis with PROSPER software within the Integrated Production Modeling (IPM) framework. Inflow Performance Relationship (IPR) analysis and nodal analysis were performed to evaluate well productivity and identify optimal production rates through sensitivity analysis. The results show that, after calibration and modeling, total production from the central gas wells increased from 368.5 to 381.1 MMSCFD. The calibrated model achieved strong agreement between actual and simulated gas rates, with an error of less than 3%, confirming the reliability of the approach. The findings demonstrate that systematic optimization and proper pressure management significantly improve well performance. The study concludes that continuous monitoring of wellhead pressure, implementation of pressure maintenance strategies, and periodic updating of IPR models are essential to sustain long-term production efficiency in gas condensate reservoirs.

تحسين أداء إنتاج المكمن الغازي المكثف في حقل بحر السلام، ليبيا

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الكلمات المفتاحية:
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اختبار التدفق المتتابع
المكمن الغازي المكثف
امتياز *NC41*
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حوض صبراتة البحري

الملخص

تتناول هذه الدراسة استراتيجيات تحسين الإنتاج في المكامن الغازية المكثفة (Gas Condensate Reservoirs)، مع التركيز على حقل بحر السلام الواقع في امتياز NC41 ضمن حوض صبراتة البحري في شمال غرب ليبيا. وتُعد المكامن الغازية المكثفة من أكثر المكامن تعقيداً في الإنتاج بسبب انخفاض الضغط، مما يؤدي إلى تراجع إنتاجية الآبار، وقدرة تدفق الغاز، وكفاءة الاستخلاص الكلية. لذلك فإن إدارة الضغط بشكل فعّال تُعد أمراً أساسياً للحفاظ على أداء المكمن وتعزيز استرجاع الهيدروكربونات. يهدف هذا العمل إلى تحسين إنتاج الغاز من الآبار المركزية في التركيب الجيولوجي "C" بحقل بحر السلام، والذي يُعد من أكبر الحقول الغازية البحرية المنتجة في المنطقة، ويمتد عبر المياه الإقليمية الليبية والتونسية. تم تحليل بيانات الحقل المقدمة من شركة مليته للنفط والغاز باستخدام تقنيات اختبار التدفق المتتابع (Flow-After-Flow). تعتمد المنهجية على دمج تحليل

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Flow-After-Flowباستخدام برنامج Excel مع برنامج PROSPER ضمن إطار نمذجة الإنتاج المتكاملة .(Integrated Production Modeling - IPM) كما تم إجراء تحليل علاقة أداء التدفق الداخل (IPR) والتحليل العقدي (Nodal Analysis) لتقييم إنتاجية الآبار وتحديد معدلات الإنتاج المثلى من خلال تحليل الحساسية. أظهرت النتائج أنه بعد عملية المعايرة والنمذجة، ارتفع إجمالي إنتاج الآبار الغازية المركزية من 368.5 إلى 381.1 مليون قدم مكعب قياسي يومياً .(MMSCFD) وقد حقق النموذج المُعاير توافقاً جيداً بين معدلات الغاز الفعلية والمحاكاة، مع خطأ أقل من 3%، مما يؤكد موثوقية المنهجية المستخدمة. وتُبين النتائج أن التحسين المنهجي وإدارة الضغط بشكل صحيح يؤديان إلى تحسين كبير في أداء الآبار. وتخلص الدراسة إلى أن المراقبة المستمرة لضغط رأس البئر، وتطبيق استراتيجيات الحفاظ على الضغط، والتحديث الدوري لنماذج IPR تُعد عناصر أساسية لضمان استدامة كفاءة الإنتاج على المدى الطويل في المكامن الغازية المكثفة.

1. Introduction

Gas reservoirs may contain non-hydrocarbon components such as nitrogen, carbon dioxide, and hydrogen sulfide, classifying them as sweet or sour depending on H_2S content [1]. This study focuses on production optimization of the Bahr Essalam gas condensate field offshore Libya (Block NC41), about 110 km northwest of Tripoli. Production began in 2005 with current rates of ~975 MMSCFD of gas and 30,000 bbl/d of condensate. The reservoir is mainly carbonate with gas specific gravity of 0.80 and condensate gravity of 51° API [2]. Gas condensate reservoirs show complex phase behavior where pressure depletion below dew point causes condensate banking, reducing productivity and gas deliverability [3], making production optimization necessary. Many wells operate below optimum capacity due to poor completion and limited evaluation [4]. Flow-After-Flow data from Mellitah Oil & Gas were used to evaluate deliverability and build IPR relationships [5], though low-permeability reservoirs require long stabilization times [6]. Well models were developed using PROSPER within IPM, integrating reservoir, wellbore, and surface systems, with calibration improving reliability [7]. Figures 1 and 2 present well locations and pressure distribution. This study evaluates well productivity and performs sensitivity analysis to determine optimum production rates while reducing liquid loading and condensate effects. Deliverability analysis uses the Flow-After-Flow method to estimate AOF and exponent (n), and PROSPER is used for modeling, matching, and IPR–VLP analysis. The reservoir has experienced pressure decline since 2011 of about 66 psi/year (Figure 2), increasing liquid loading and condensate banking, reducing deliverability and risking premature shutdown.

The study improves understanding of gas condensate behavior and provides optimization guidance, but is limited to selected central wells with SBHP data from only nine wells, so results do not represent the full field.

2. Literature Review

Gas condensate reservoirs are important hydrocarbon systems that initially exist as single-phase gas. When reservoir pressure falls below the dew point, retrograde condensation occurs, causing liquid dropout in the pores and reducing gas and condensate productivity [8].

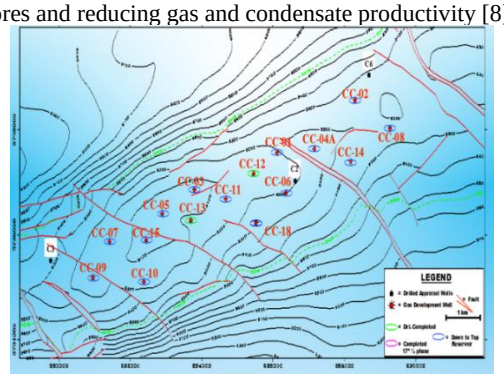


Figure 1: Bahr Essalam wells location of selected area (Mellitah, 2020).

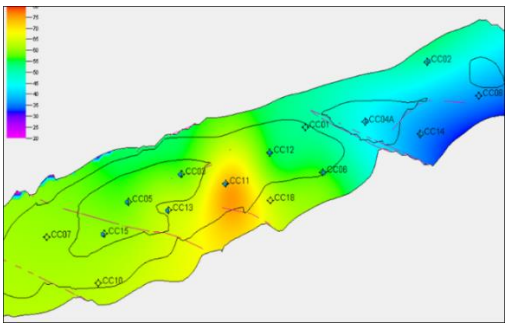


Figure 2: Bahr Essalam Field Reservoir Central Area Pressure Distribution.

Condensate accumulation near the wellbore leads to condensate banking, which lowers gas relative permeability and well deliverability [2]. Recovery factors under depletion drive conditions are typically 40–60% for gas and 10–30% for condensate [1]. When pressure drops below the dew point, condensate forms and increases near-wellbore saturation, reducing flow efficiency due to lower relative permeability. Phase behavior modeling using equations of state such as Peng–Robinson improves prediction of gas condensate performance under depletion conditions [12]. Condensate banking results from liquid accumulation near the wellbore and causes multiphase flow interference and productivity loss, which in severe cases can reduce well performance by up to 90% [1]. Gas condensate reservoirs also face key challenges including condensate banking, liquid loading, phase behavior uncertainty, and declining gas deliverability [8]. Production optimization techniques include gas recycling to maintain reservoir pressure above dew point and reduce condensate dropout, improving recovery [10]. CO_2 injection enhances condensate vaporization and sweep efficiency [11]. Hydraulic fracturing helps bypass damaged zones and condensate banks in low-permeability reservoirs [6], while horizontal wells improve reservoir contact and increase recovery compared to vertical wells [9]. Chemical treatments such as surfactants and solvents reduce condensate blockage by improving gas relative permeability near the wellbore. Integrated Production Modeling (IPM) tools such as PROSPER are widely used for nodal analysis and system optimization across reservoir, wellbore, and surface facilities [13]. Recent studies (2024–2026) focus on compositional simulation, horizontal well development, gas recycling optimization, and machine learning methods to improve prediction accuracy and enhance recovery performance in gas condensate reservoirs [14].

3. Bahr Essalam Field, NC41 Concession, Sabratah Offshore Basin, Northwest Libya

The Sabratah Basin lies on the Pelagian Shelf extending from Tunisian waters into offshore northwest Libya (see Figure 3 Satellite Image of Libya's Sedimentary Basins), covering ~24,000 km² between the Jifarah Terrace and Jarrafa Arch and bounded by major tectonic structures [16][17]. It hosts major hydrocarbon accumulations, including the Bahr Essalam Field, Libya's largest offshore gas field, operated by Mellitah Oil & Gas (NOC/Eni) and supplying gas to Italy via the Greenstream pipeline [18]. Within NC41, structure "C" represents Bahr Essalam (see Figure 4 NC41 Concession and Bahr Essalam "C" Structure Location Map), formed by WSW–ENE

anticlines [19]. The field is located 110–120 km northwest of Tripoli at ~600 ft water depth. Production started in 2005, reaching ~975 MMSCFD gas and 30,000 bbl/d condensate [20]. The reservoir is mainly carbonate (limestone) with gas specific gravity of 0.80 and condensate gravity of 51° API. It is divided into Western, Central A, Central B, and Eastern sectors (see Figures 5–6), with stronger faulting in the western sector [21].

A thin oil rim exists in Central B and Eastern areas (80 ft and 35 ft), supported by bottom and edge aquifers (Figure 6 Reservoir Zonation) [22]. The reservoir belongs to the Eocene Metlaoui Group (>900 ft thickness) [23]. Continuous optimization is required due to gas-condensate behavior [24], while integrated geological and geochemical studies improve characterization [25]. Gas well testing includes transient, production, and deliverability analysis using Flow-After-Flow multipoint tests to establish IPR from back-pressure testing (Figure 7) [26][27]. Full stabilization is often not achieved due to operational constraints [28][29].

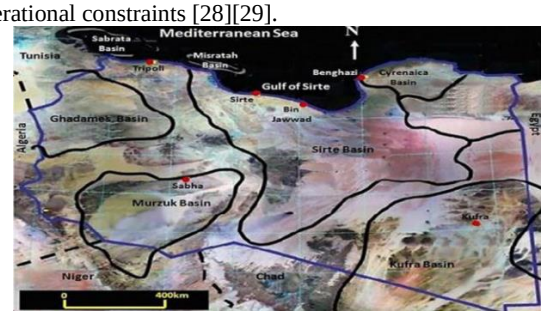


Figure 3: Satellite Image of Libya's Sedimentary Basins (Shaltami et al., 2022)

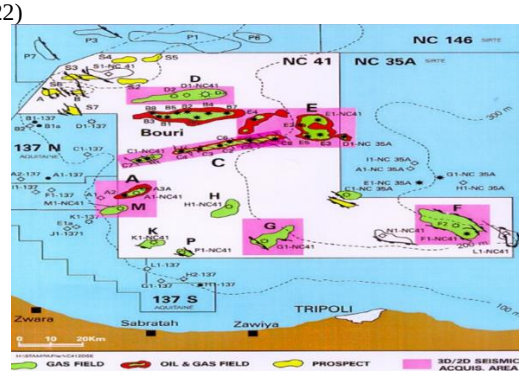


Figure 4: NC41 Concession and Bahr Essalam "C" Structure Location Map

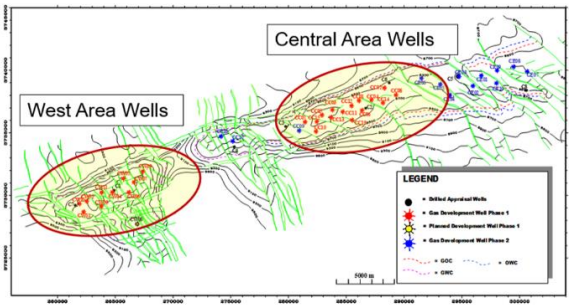


Figure 5: Central and West Area Wells Map

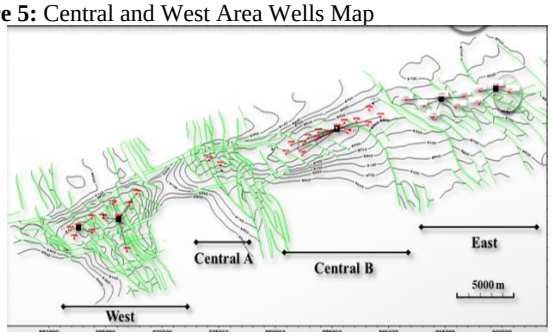


Figure 6: Field Areas Map (West, Central A, Central B, and East)

The Rawlins and Schellhardt method is used for gas well deliverability estimation [30]. Approximate stabilization is assumed when pressure variation is minimal over short periods (~15 min) [31]. The IPR curve is widely used for productivity evaluation and decline forecasting [32]. AOFP is the theoretical maximum gas rate at zero bottom-hole pressure, estimated from deliverability data for operational and regulatory use [33]. Multipoint back-pressure testing remains reliable in heterogeneous and low-permeability reservoirs [34]. Data were obtained from Central Area wells in the Bahr Essalam Field (see Figure 8 and Table 1).

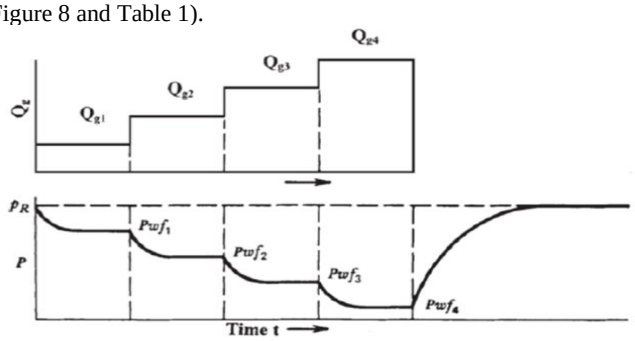


Figure 7: Conventional multi-point test (Smith, 1990).

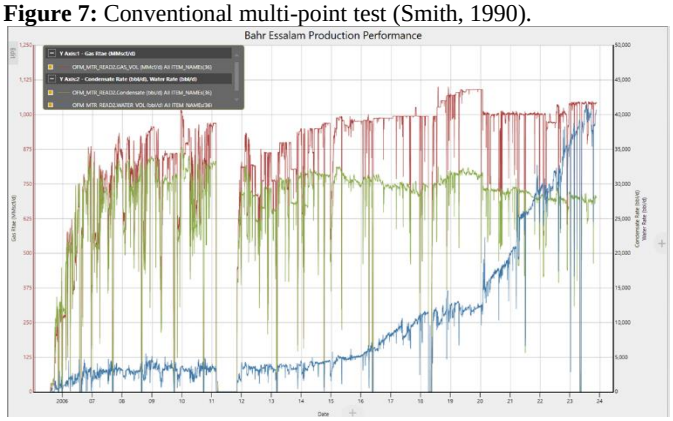


Figure 8: Bahr Essalam Field Production Performance

Routine production data for the selected Central Area wells show a total production of about 368.5 MMSCFD, with WHP ranging from 140–157 barg and reservoir pressure around 76 barg. The production-performance record shown in Figure 8 covers 2005–2024. Figure 9 shows the SBHP trend at datum, including an average pressure decline of approximately 66 psi/year [35]. After 2009, the decline slows, suggesting partial aquifer support or undeveloped eastern zones [36]. The western area shows stronger depletion (well CC11), indicating a possible pressure sink and water coning risk [37], while the eastern area shows lower depletion (~55 psi/year) with stronger pressure support [38].

The well data (CC01–CC18) show variations in choke size, WHP, WHT, gas rate, and test pressure, with total production of 368.5 MMSCFD, confirming the overall field performance level.

4. Methodology

Research Steps: Analytical and simulation work was performed using Microsoft Excel and PROSPER to integrate gas deliverability analysis with production system modeling for well evaluation and optimization in Bahr Essalam field [39].

Data Collection and Analysis Period: The production-performance record used in this study spans 2005–2024. The deliverability and PROSPER analyses use the available Flow-After-Flow, SBHP, well-test, and production records for the selected Central Area wells. The optimization comparison uses 368.5 MMSCFD as the baseline and 381.1 MMSCFD as the modeled post-optimization production rate.

General Workflow Steps: Figure 10 shows the overall methodology workflow from data collection and quality control through deliverability analysis, PROSPER modeling, matching, sensitivity analysis, and production optimization [40].

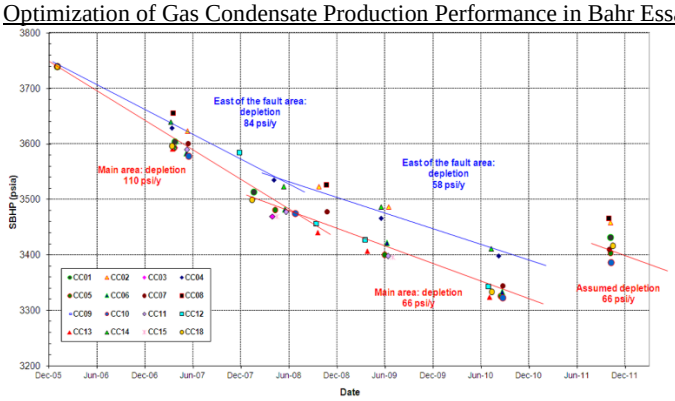


Figure 9: Bahr Essalam Field – SBHP at Datum (Central Area)

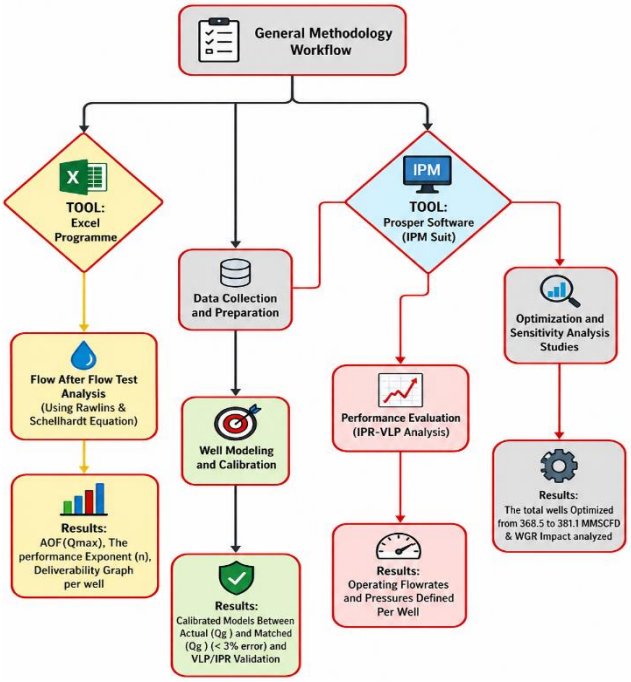


Figure 10: General Methodology Workflow for Gas Condensate Well Performance Optimization

Flow-After-Flow Test Analysis (Test #1): The Flow-After-Flow deliverability test was implemented in Excel. The Back-Pressure Test defines the inflow performance relationship between gas rate and bottom-hole flowing pressure or WHP, used to estimate production under varying conditions [41]. The Rawlins and Schellhardt equation is the main gas deliverability model [42].

$$Q_g = C\left(P_r^2 - P_{wf}^2\right)^n$$

Qg = Gas flow rate, scf/day
Pr = Reservoir pressure, psia
Pwf= Bottom-hole flowing pressure, psia
C= Performance coefficient
n= Deliverability exponent

If the coefficients C and n are determined, the gas flow rate at any bottom-hole flowing pressure can be estimated. Taking logarithms of both sides gives [43]:

$$\log(Q_g) = \log(C) + n\log(P_r^2 - P_{wf}^2)$$

This equation indicates that plotting flow rate against pressure-squared drawdown on logarithmic scales produces a straight line. In practice, the industry often reverses the plot and graphs (Pr2−Pwf2) versus Qg, resulting in a line with slope 1/n1. This graph is commonly known as the Deliverability Curve or Back-Pressure Plot, as shown in Figure 11 [44].

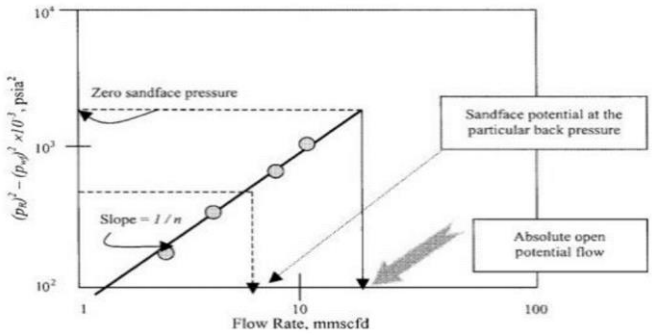


Figure 11: Well Deliverability Curve (Chaudhry, 2003)

The deliverability exponent n can be calculated from any two points on the straight line:

$$n = \frac{\log(Q_{g2}/Q_{g1})}{\log(\Delta P_2^2/\Delta P_1^2)}$$

Once n is known, the performance coefficient C can be calculated from:

$$C = \frac{Q_g}{(P_r^2 - P_{wf}^2)^n}$$

The inflow performance calculations were based on four production test periods for each well. Deliverability testing has long been used in the petroleum industry to evaluate gas well flow potential and productivity [45].

PROSPER Software (Test #2): PROSPER is a petroleum engineering software by Petroleum Experts Ltd. used for production system analysis, well modeling, tubing hydraulics, pipeline flow, and optimization [46]. It predicts pressure losses, temperature behavior, and system performance, and includes sensitivity tools for optimization and forecasting [47]. Within the IPM framework, PROSPER is used for well performance evaluation and optimization [48]. Figure 12 shows the PROSPER workflow shows the modeling procedure.

The software process consists of four phases (Figure 13). Phase 1 builds a well model using PVT, IPR, well trajectory, tubing, and surface data [49]. Phase 2 matches the model with well test data to represent real field behavior [50]. Phase 3 analyzes inflow, outflow, choke, and surface constraints [51]. Phase 4 optimizes production by identifying bottlenecks and applying sensitivity analysis [52].

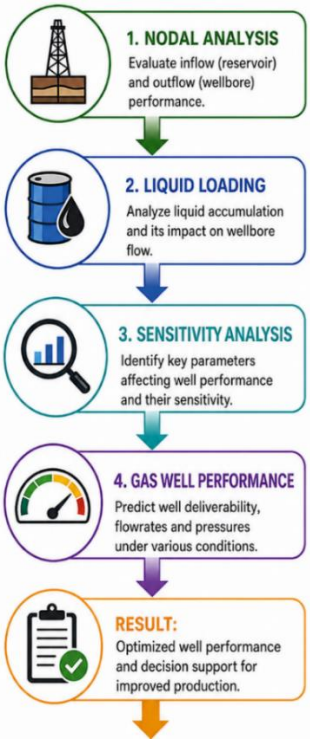


Figure 12: Single Well Performance Model Workflow.



Figure 13: Workflow for Well Modeling and Performance Analysis

5. Results and Discussion

Results of Static Bottom-Hole Pressure for Central Wells: The PROSPER model calibration for the Central Wells Area of the Bahr Essalam Field compares actual and simulated gas production rates for each well. The results show very close agreement between measured and matched values, with errors below 3%, confirming high model accuracy and reliable calibration.

The comparison indicates consistent performance across wells such as CC-01, CC-05, CC-06, CC-12, and CC-18, as well as CC-04, CC-10, CC-13, and CC-14, all showing minimal deviations between actual and simulated rates. The total production of 368.5 MMSCFD represents the baseline field performance prior to optimization. Overall, the results confirm that the PROSPER model is well calibrated and suitable for further performance evaluation and optimization analysis.

To achieve 381.1 MMSCFD, choke-up was applied to wells with lower bottom-hole pressure differentials along with WHP adjustments. The results show overall improved field performance. Well-wise, CC-01, CC-05, and CC-06 show clear production increases after optimization. CC-10 shows only slight improvement despite high pressure differential, while CC-12 and CC-18 show small gains with stable behavior. In contrast, CC-04, CC-13, and CC-14 show minimal change or slight reduction, indicating limited response to adjustments. Overall production increased from 368.5 to 381.1 MMSCFD (~3.4%), confirming that small operational changes in choke and pressure control improve gas deliverability.

Long-Term Evaluation: The modeled increase represents the immediate optimization response and does not, by itself, establish long-term sustainability. A practical field evaluation period of 6–12 months is recommended after implementation, with monthly tracking of gas rate, WHP, SBHP, condensate, and water production and at least quarterly review and updating of the PROSPER/IPR models. This period would allow the operator to distinguish sustained performance improvement from short-term operational effects and to adjust choke and pressure-management settings as reservoir conditions evolve.

Results from Excel Sheet: Deliverability tests were conducted on Central Area wells in the Bahr Essalam Field to evaluate flow capacity. Seven wells were tested at multiple rates using four choke sizes, with downhole gauges recording bottom-hole pressure. AOF was calculated using the back-pressure equation in Excel. The deliverability results show the performance exponent (n) and AOF for seven wells, indicating variations in production potential across the field. Wells CC06, CC04, and CC14 have the highest AOF values, showing stronger production capacity, while CC18 shows moderate potential. CC12, CC13, and CC05 have lower AOF values, indicating reduced deliverability compared to the top wells. Overall, the results highlight clear differences in well productivity, useful for future optimization and production planning.

Representative AOF deliverability curves are retained for wells CC04, CC06, and CC18 (Figures 14–16). The remaining well results are summarized in Table 2. The AOF values range from approximately 208 to 899 MMSCFD, with CC06 showing the highest theoretical deliverability. The retained curves demonstrate the linear log–log trend used with the Rawlins and Schellhardt relationship.

Table 2: Summary of AOF deliverability results for the selected Central Area wells.

Well	AOF (MMSCFD)	Interpretation
CC04	~660	High deliverability
CC05	~208	Lower deliverability
CC06	~899	Highest deliverability
CC12	~280	Moderate deliverability
CC13	~210	Lower deliverability
CC14	~659	High deliverability
CC18	~387	Moderate deliverability

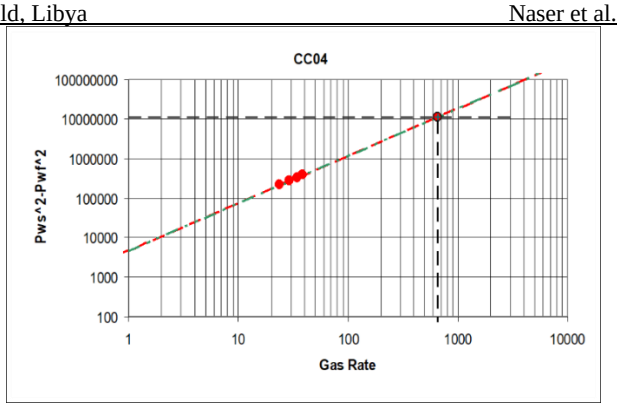


Figure 14: Bahr Essalam Central Area – Gas Well CC04 (AOF Deliverability Curve)

Well Performance Using PROSPER Software: IPR and VLP data were defined as multipoint inputs using a multi-rate C and n approach based on well-test data at different flow rates. From Figure 17, the inflow–outflow intersection for CC04 gives an operating flow rate of ~39.8 MMSCFD at 150 barg. The pressure differential of ~78.5 psi confirms a well-calibrated and consistent flow system.

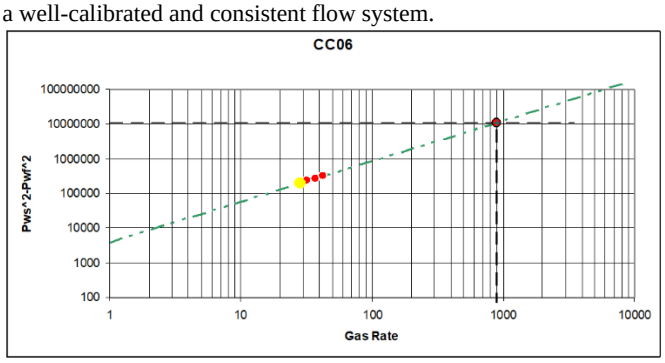


Figure 15: Bahr Essalam Central Area – Gas Well CC06 (AOF Deliverability Curve)

VLP Matching tunes multiphase-flow correlations to match downhole pressure data, while IPR matching adjusts inflow parameters so that the VLP/IPR intersection agrees with actual rates. The complete well-by-well operating results are summarized in Table 3. For CC01, the modeled rate increases from approximately 35.3 MMSCFD at 151 barg to 52.5 MMSCFD at 135 barg, demonstrating the benefit of lower WHP.

The IPR–VLP results are summarized in Table 3, while representative matches are retained for CC04, CC06, and CC18 (Figures 17–19). The results show that reducing the top-node pressure generally increases gas rate, while the magnitude of the response varies by well. For CC05, for example, reducing top-node pressure from 147 to 130 barg increases the modeled gas rate from 38.2 to 44.1 MMSCFD.

Table 3: Summary of IPR–VLP operating points for the selected Central Area wells.

Well	Top-node pressure (barg)	Modeled gas rate (MMSCFD)	Comment
CC04	150	~39.8	Representative match
CC01	151 / 135	~35.3 / 52.5	Rate increases as WHP is reduced
CC05	147 / 130	38.2 / 44.1	Rate increases with lower top-node pressure
CC06	151	~45.47	Representative match
CC10	140	~35.78	Operating point
CC12	157	~41.86	Operating point
CC13	151	~38.59	Operating point
CC14	150	~40.47	Operating point
CC18	150	~42.27	Representative match

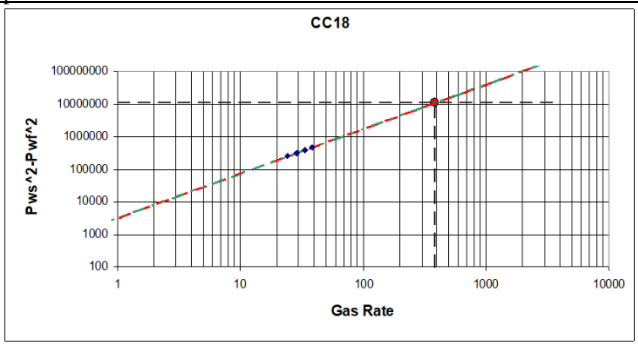


Figure 16: Bahr Essalam Central Area – Gas Well CC18 (AOF Deliverability Curve)

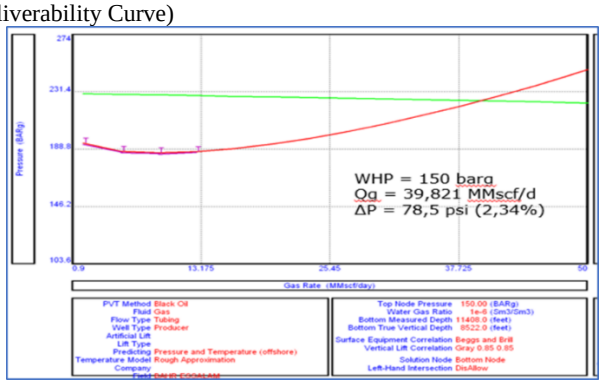


Figure 17: Bahr Essalam Central Area – Gas Well CC04 (IPR–VLP Matching)

5.4. Sensitivities to Water Production

Water-production sensitivity was evaluated for CC01 and CC10. For both wells, a 50% KH reduction was applied at WGR = 100 bbl/MMscf and a 75% reduction at WGR = 200 bbl/MMscf. The calculated responses are summarized in Table 4. Representative 2021 sensitivity plots are retained in Figures 20–21. For CC01, the comparison indicates increased water sensitivity in the later period, consistent with water encroachment and liquid loading.

Table 4: Summary of water-production sensitivity for CC01 and CC10.

Well	KH (md·ft)	KH reduction at WGR 100	KH reduction at WGR 200	Observed period response
CC01	44,311	50%	75%	Higher sensitivity in 2021; consistent with water encroachment/liquid loading
CC10	9,038	50%	75%	Stable at low WGR in 2012; sharper decline at higher WGR in 2021

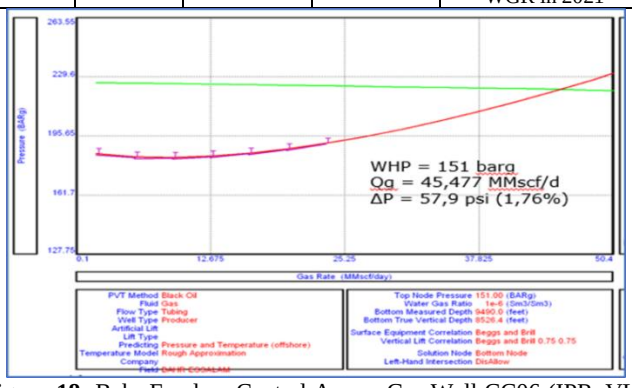


Figure 18: Bahr Essalam Central Area – Gas Well CC06 (IPR–VLP Matching)

For CC10, the calculated KH is 9,038 md·ft. The 2012 response was comparatively stable at low WGR, whereas the 2021 response declined sharply at higher WGR, indicating more advanced water breakthrough and increased pressure losses. Water-control measures should therefore be prioritized for wells showing this response.

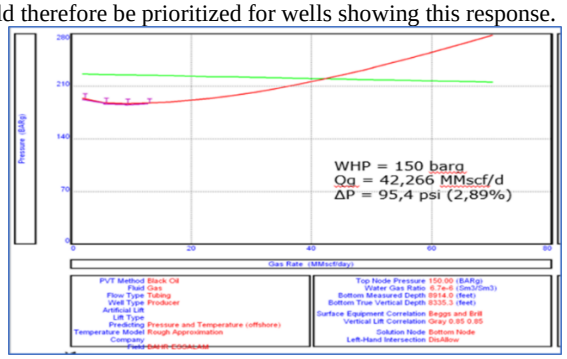


Figure 19: Bahr Essalam Central Area – Gas Well CC18 (IPR–VLP Matching)

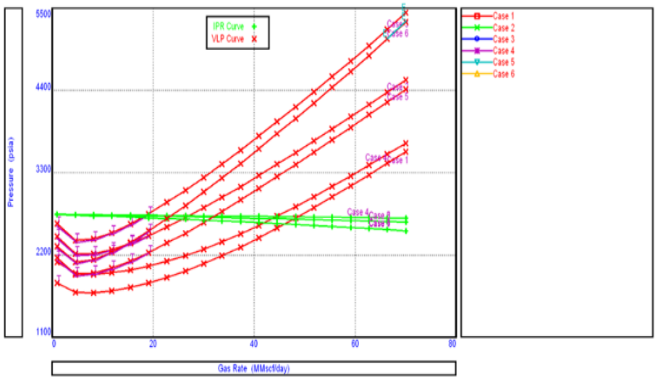


Figure 20: Bahr Essalam Central Area – Gas Well CC01 (WGR Sensitivity, 2021)

6. Conclusions and Recommendations

6.1. Conclusions

This study investigated production optimization in the Bahr Essalam gas condensate field, identifying key challenges and recovery opportunities. Results confirm that retrograde condensation and condensate banking reduce gas deliverability and productivity. A combined Excel Flow-After-Flow and PROSPER workflow was used for well evaluation and optimization. IPR analysis showed productivity decline with reservoir pressure depletion (~66 psi/year). PROSPER nodal analysis identified flow constraints and bottlenecks in Central Area wells. Model calibration showed strong agreement between measured and simulated results (error <3%). Optimization increased production from 368.5 to 381.1 MMSCFD (~3.4%). Water sensitivity showed WGR-dependent response (2–6 kbwpd tolerance). Gas condensate reservoirs require advanced optimization due to phase behavior and pressure sensitivity. The study provides practical guidance for similar offshore fields.

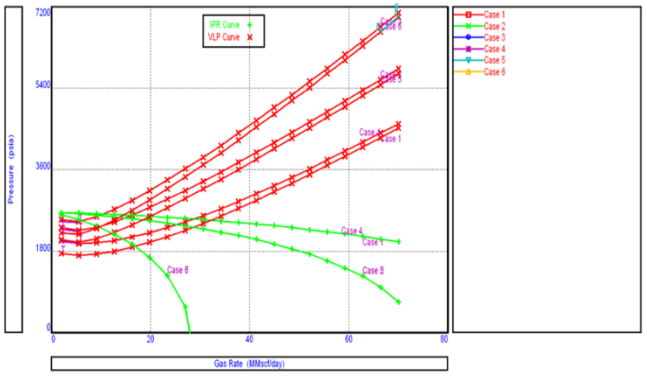


Figure 21: Bahr Essalam Central Area – Gas Well CC10 (WGR Sensitivity, 2021)

6.2. Recommendations

Continuous monitoring of reservoir pressure, condensate and water production is recommended. Periodic well testing and PROSPER updates improve prediction. Optimizing FTHP enhances gas deliverability. Water breakthrough wells should be prioritized for control. Further work should address condensate banking using gas

recycling and stimulation. Future studies should apply AI and real-time data. Economic and environmental evaluations are required. Similar studies are recommended for other areas, and performance improves with better management.

Nomenclature

Qg — gas flow rate, scf/day
Pr — reservoir pressure, psia
Pwf — bottom-hole flowing pressure, psia
C — gas-well performance coefficient
n — deliverability exponent
AOF/AOFP — absolute/absolute open-flow potential
IPR — inflow performance relationship
VLP — vertical lift performance
WHP — wellhead pressure
WHT — wellhead temperature
SBHP — static bottom-hole pressure
WGR — water–gas ratio
KH — permeability–thickness product
IPM — Integrated Production Modeling
MMSCFD — million standard cubic feet per day

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