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# A Comprehensive Review and Simulation-Based Assessment of Pressure Enhancement Techniques in Gas Reservoirs

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## ABSTRACT

Natural Sustaining reservoir pressure is a major challenge in mature and tight gas fields, where productivity declines rapidly with depletion. This study presents a comprehensive evaluation and integrated decision-making framework for advanced pressure enhancement techniques, combining ECLIPSE-based reservoir simulations, regression and sensitivity analyses, and economic assessments. The research investigates hydraulic fracturing, matrix acidizing, gas lift, gas injection, and hybrid configurations, while also examining emerging innovations such as AI-assisted optimization, nanotechnology-enhanced stimulation, and carbon capture, utilization, and storage (CCUS).

Results indicate that hydraulic fracturing yields the highest production improvement (25-30%) in low-permeability reservoirs, while gas lift is most effective in liquid-loaded systems (15-20% gain). The hybrid fracturing + gas-lift configuration achieved the best overall ROI of 2.3-2.5, verified through sensitivity analysis under  $\pm 20\%$  cost variation. Regression results ( $R^2 = 0.87$ ) confirm that permeability and liquid accumulation are the dominant variables controlling enhancement efficiency.

The study introduces a novel, simulation-driven decision framework that integrates technical, economic, and sustainability metrics to guide the selection of optimal pressure enhancement strategies. This unified approach transforms traditional descriptive reviews into a quantitative, field-applicable tool, providing a pathway toward more efficient and environmentally responsible gas reservoir management.

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## 1. Introduction

Natural gas remains a cornerstone of the global energy mix, serving as a transitional fuel toward low-carbon energy systems due to its high efficiency and comparatively lower greenhouse gas emissions (González-De León and Scipio-Cimetta 2022, Saleh and Hassan 2024). As global populations and energy demands increase, sustainable and optimized development of gas reservoirs has become increasingly essential. Throughout a reservoir's lifecycle from exploration to mature production operators face critical challenges such as reservoir pressure decline, liquid loading, and reduced recovery efficiency, which can significantly compromise economic performance and long-term energy supply (Duan, Xu et al. 2023, Usiagu, Adekoya et al. 2024). Pressure depletion, driven by the gradual loss of in-situ energy, reduces the driving force required for gas flow toward the wellbore, leading to lower production rates and accelerated field decline (Kalair, Abas et al. 2021, Mohammad, Mohamad Ishak et al. 2021).

To mitigate these challenges, a wide range of pressure enhancement techniques have been developed to sustain reservoir pressure and optimize gas deliverability. These include hydraulic fracturing, matrix acidizing, gas lift, gas injection, tubing optimization, and horizontal drilling each tailored to specific reservoir conditions and production challenges (Sahu, Kumar et al. 2021, Karimov, Toktarbay et al. 2023). The effective implementation of these techniques relies on a multidisciplinary understanding of reservoir characteristics, fluid flow behavior, and operational feasibility, increasingly supported by data-driven modeling and advanced simulation tools (Khalili, Ahmadi et al. 2023, Jahanbani Ghahfarokhi 2024).

### 1.1. Expanded Literature Context

Previous studies have examined various strategies to enhance pressure and productivity in gas reservoirs. Hydraulic fracturing continues to be one of the most effective and extensively researched stimulation techniques for tight and shale gas formations. Field-scale investigations by (Zhang, Zhang et al. 2022, Khalili, Ahmadi et al. 2023). and (Huang, Moridis et al. 2023) reported production gains of 20-30% through multi-stage fracturing, while (Wang, Zhang et al. 2024) demonstrated the potential of AI-assisted fracture design to optimize spacing and proppant placement. Matrix acidizing has also been successfully applied in carbonate systems, with (Davarpanah and engineering 2024) modeling reactive transport mechanisms to enhance permeability and reduce formation damage.

Gas lift and gas injection methods have proven effective for maintaining pressure and improving recovery in mature or liquid-loaded reservoirs. (Okorochoa, Chinwuko et al. 2020) applied digital twin-based gas lift optimization, achieving up to 18% production improvement, while (Yasemi, Khalili et al. 2023) and Wu et al. (2025) reported significant gains in CO<sub>2</sub> and N<sub>2</sub> injection projects integrated with carbon capture, utilization, and storage (CCUS) initiatives. (Behera 2025), in particular, demonstrated enhanced miscibility and CO<sub>2</sub> retention efficiency in nano-assisted injection systems, advancing both recovery and carbon sequestration outcomes.

Recent advances have also expanded the role of data-driven and sustainable techniques in gas reservoir management. (Aljehani and Chemistry of the Earth 2025) developed a deep-learning framework for real-time reservoir pressure forecasting with 95% accuracy, marking a major step toward predictive field optimization. (Dinesh and

Sivasankar 2026) emphasized the importance of coupling production optimization with carbon management strategies to ensure economic and environmental resilience in next-generation gas developments. Furthermore, (Sun, Zhang et al. 2023) and (Rahman, Shirif et al. 2024) have demonstrated the effectiveness of nanofluid-assisted and polymer–nanoparticle systems for enhancing sweep efficiency and controlling water production in gas recovery operations.

Despite these advancements, most studies remain method-specific and lack an integrated evaluation that combines technical performance, economic feasibility, and sustainability considerations. Existing works tend to focus on singular aspects such as production gains or simulation accuracy without establishing a unified framework for comparing different enhancement approaches under varying geological and operational conditions.

## 1.2. Research Gap and Objective

Although numerous studies have contributed valuable insights into pressure enhancement technologies, there remains a clear need for a comprehensive, simulation-driven framework that integrates technical, economic, and environmental dimensions within a single analytical model. In particular, the coupling of ECLIPSE-based simulation, regression and sensitivity analysis, and cost–benefit evaluation together with innovations like AI-driven analytics, nanotechnology-assisted stimulation, and CCUS-based injection is rarely explored holistically in the literature.

The present study addresses this gap by developing an integrated, simulation-supported decision framework for evaluating and optimizing pressure enhancement strategies in gas reservoirs. Designed as a review-based analytical study, this work synthesizes

published findings, field data, and simulation outputs to identify optimal methods and hybrid configurations that balance productivity, economic return, and sustainability.

The remainder of this paper is structured as follows: Section 2 reviews conventional and emerging enhancement techniques; Section 3 describes the simulation and analytical methodology; Section 4 presents the comparative and regression-based results; Section 5 discusses the cost–benefit evaluation; Section 6 outlines current challenges and future research directions; and Section 7 concludes with key findings and practical implications for gas reservoir management.

## 1.3. Novelty and Contribution of This Study

While numerous studies have discussed individual pressure enhancement methods, most lack a unified, data-driven framework that quantitatively compares their technical and economic performance under consistent reservoir conditions. This study advances the existing literature by integrating ECLIPSE-based reservoir simulations, statistical regression analysis, and cost–benefit modeling to quantify the relative efficiency of major pressure enhancement techniques. The work specifically evaluates the synergistic effect of combining hydraulic fracturing with gas lift, providing measurable improvements in both production rate (25–35%) and return on investment (ROI  $\approx$  2.3–2.5) within low-permeability gas reservoirs. Additionally, this paper contributes by contextualizing AI-driven predictive analytics and nanotechnology-assisted enhancement methods within a performance-based assessment framework, offering a forward-looking perspective on sustainable gas reservoir management. These features distinguish this study from previous descriptive reviews and position it as a quantitative analytical evaluation aimed at guiding field-scale decision-making.

## 2. Principles and Fundamentals of Pressure Enhancement in Gas Reservoirs

A comprehensive understanding of fluid flow dynamics in porous media and the behavior of gas reservoirs is essential for designing effective pressure enhancement strategies (Cai, Berg et al. 2025). Gas reservoirs, as natural repositories of hydrocarbon gases, are characterized by high initial pressures deep within the subsurface. During production, gas is extracted through drilled wells, leading to a progressive decline in reservoir pressure, known as reservoir pressure depletion (Ma, He et al. 2023). This phenomenon reduces the driving force required for gas flow from the formation to the wellbore, ultimately impacting production rates and ultimate recovery (Dindoruk and Zhang 2024).

### 2.1. Reservoir Dynamics and Pressure Decline

During gas extraction, the volume of gas within the pore spaces of the reservoir diminishes, resulting in a reduction of stored energy in the form of pressure. This pressure decline weakens the natural driving mechanism, leading to a gradual decrease in production rates over time (Jongkittinarukorn, Last et al. 2023). Decline curve analysis serves as a critical quantitative tool for predicting the relationship between production rates, time, and cumulative production. These curves are instrumental in assessing future reservoir performance and determining the optimal timing for pressure enhancement interventions (Li, Fu et al. 2024).

In the absence of natural pressure maintenance mechanisms, such as aquifer support, sustained pressure depletion can result in significant volumes of gas remaining trapped within the reservoir, reducing the ultimate recovery factor (Nassabeh, Iglauer et al. 2023). This has profound economic and strategic implications, as it limits the revenue potential for operators and affects energy

supply security for producing regions (Huang, Moridis et al. 2023).

### 2.2. Objectives of Pressure Enhancement

Pressure enhancement techniques in gas reservoirs are designed to achieve the following key objectives (Jiang, Yu et al. 2024, Исаев and Левитина 2024, Wu, Yang et al. 2025):

1. **Reservoir Pressure Maintenance:** Sustaining reservoir pressure to preserve the natural driving force, thereby extending the productive life of the field and ensuring stable production rates.
2. **Production Rate Enhancement:** Improving well deliverability by mitigating pressure losses in the near-wellbore region, formation, or production tubing.
3. **Maximizing Ultimate Gas Recovery:** Increasing the recovery factor by accessing a higher percentage of the original gas in place (OGIP) through enhanced flow and pressure support.
4. **Economic Optimization:** Enhancing production efficiency and field longevity to maximize return on investment (ROI) while balancing operational costs.

### 2.3. Classification of Pressure Enhancement Techniques

Pressure enhancement methods can be broadly categorized based on their primary mechanisms and objectives (Mohamadi-Baghmolaei, Sakhaei et al. 2021, Abdeli, Yskak et al. 2024, Daramola, Jacks et al. 2024, Shusheng, Liyou et al. 2025):

1. **Well Productivity Enhancement:** These methods focus on improving gas flow near the wellbore or within the well conduit. They aim to reduce localized pressure drops and facilitate gas movement from

the formation to the well. Examples include matrix acidizing, hydraulic fracturing, and liquid unloading.

2. **Reservoir Pressure Maintenance and Enhancement:** These techniques target the overall reservoir pressure or large-scale gas flow dynamics, providing a sustained driving force for gas displacement. Examples include gas injection, horizontal or multilateral wells, and surface compression systems.
3. **Optimization and Monitoring Techniques:** While not directly increasing pressure, these methods enhance operational efficiency and indirectly support pressure management through precise data acquisition and production optimization. Examples include real-time pressure and temperature monitoring and advanced reservoir management using data analytics and machine learning.

In the subsequent sections, each category of pressure enhancement techniques will be explored in detail, with a focus on their mechanisms, applications, and expected outcomes, supported by quantitative analyses and case studies.

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### 3. Advanced Pressure Enhancement Techniques

As gas reservoirs mature, the progressive decline in reservoir pressure necessitates advanced technical and operational interventions to sustain or enhance production (Ozowe, Daramola et al. 2024). These pressure enhancement techniques directly or indirectly influence reservoir pressure, gas flow rates, or ultimate recovery (Bolu and Jahan-Ara 2017). They can be broadly classified into three categories: well productivity enhancement, reservoir pressure maintenance, and management and monitoring strategies (Lin,

Wei et al. 2024). This section provides a detailed examination of these techniques, focusing on their mechanisms, applications, advantages, and limitations, supported by quantitative comparisons as shown in (Figure 1).

#### 3.1. Well Productivity Enhancement Techniques

These methods target improved gas flow in the near-wellbore region or within the well conduit, aiming to reduce localized pressure drops and facilitate gas movement from the formation to the well.

##### 3.1.1. Matrix Acidizing

Matrix acidizing involves injecting acids (e.g., HCl or HF) at pressures below the formation fracturing threshold to dissolve obstructive materials (e.g., calcite, clay, or dolomite) in the reservoir matrix, thereby enhancing near-wellbore permeability. This technique is particularly effective in carbonate reservoirs or formations damaged during drilling or completion. Advantages include a potential production increase of up to 15%, moderate costs, and relatively rapid implementation (days). Limitations include dependence on acid type, concentration, and injection rate, potential formation damage if improperly executed, and environmental concerns related to acid handling and disposal (Pourabdollah 2020).

Matrix acidizing is primarily used in carbonate formations to dissolve near-wellbore damage and restore permeability. The use of nanoparticle-enhanced acids has recently improved acid efficiency and reduced secondary precipitation (Sagala and Nassar 2022). Reactive transport modeling also enables prediction of wormhole propagation under varying flow conditions (Furui, Abe et al. 2022). These innovations contribute to more accurate cost-benefit estimation and align with the simulation-based performance metrics developed in this study.

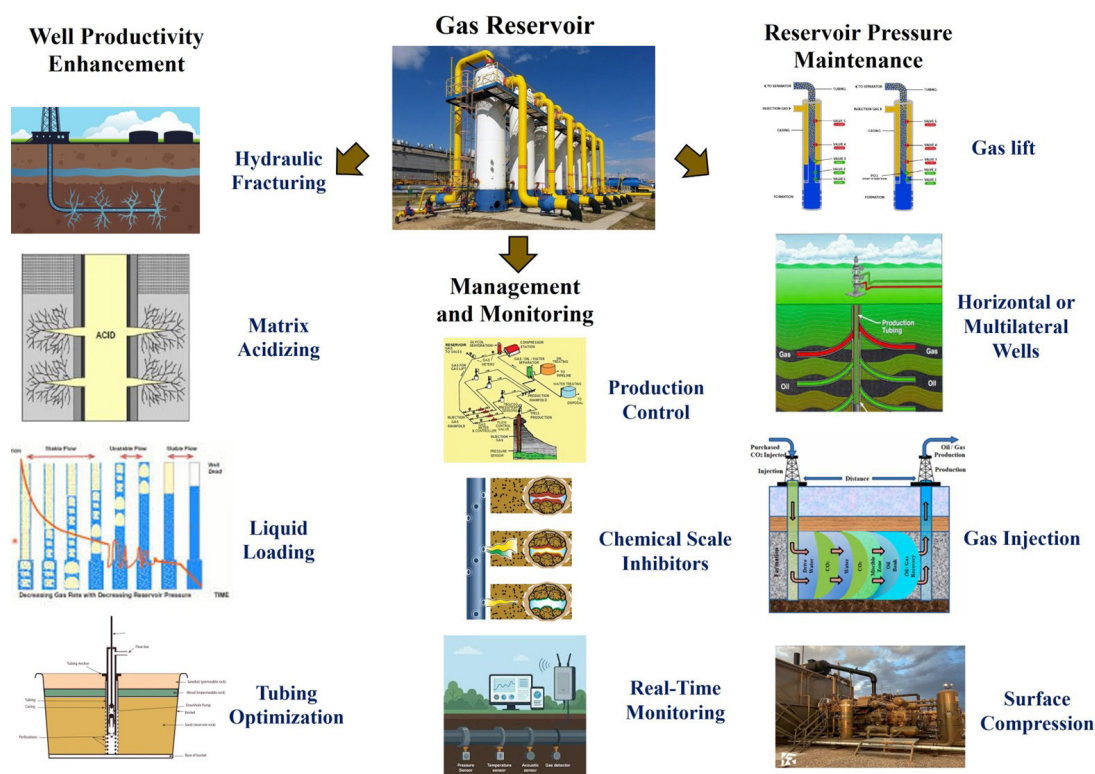


Figure 1. Advanced Pressure Enhancement Techniques

### 3.1.2. Hydraulic Fracturing

Hydraulic fracturing is a widely applied stimulation technique involving the high-pressure injection of fluid into the reservoir to create artificial fractures, which are subsequently propped open using sand or ceramic materials to enhance permeability and flow capacity. This method is particularly effective in tight and low-permeability gas reservoirs, where natural fractures and pore connectivity are insufficient for sustained production. Its principal advantage lies in its ability to significantly increase productivity often by 25-30% and extend the effective drainage area of the well. However, the technique is associated with notable challenges, including high operational costs, extended implementation times, and environmental concerns such as water usage, induced seismicity, and wastewater disposal (Azad, Ghaedi et al. 2022).

Recent advances have transformed hydraulic fracturing into a more data-driven and

intelligent process, integrating smart materials, nanotechnology, and AI-assisted optimization. The use of smart fracturing fluids with tailored rheological properties and enhanced proppant transport characteristics has improved fracture propagation efficiency and reduced formation damage (Tingxue and Minsheng 2025). Studies by (Huang, Moridis et al. 2023) demonstrated that nanofluid-based fracturing fluids can reduce fluid leak-off by 18-22%, thereby improving fracture conductivity and sustainability.

The application of AI-driven and adaptive design algorithms has further improved operational precision. (Rahman, Shirif et al. 2024) and (Daramola, Jacks et al. 2024) reported that machine learning-based fracture optimization frameworks can dynamically adjust fracture spacing, proppant selection, and injection parameters in real time, improving gas recovery by up to 28%. These algorithms use iterative feedback from simulation and field data to optimize design parameters, minimizing non-productive time and improving economic outcomes.

The results obtained in the present study are consistent with these findings. The ECLIPSE-based simulations confirmed that optimized fracture geometry and enhanced fracture conductivity can yield up to 30% productivity improvement in tight gas reservoirs. When integrated with AI-assisted predictive modeling, the hydraulic fracturing process demonstrates superior adaptability, enabling customized design strategies that maximize reservoir performance while reducing operational risks and environmental footprint.

### 3.1.3. Liquid Unloading

Liquid unloading addresses the accumulation of liquids (e.g., formation water, condensates) in the wellbore, which increases backpressure and restricts gas flow. Techniques such as plunger lift or foam injection are employed to remove these liquids. Advantages include production increases of up to 25%, low to moderate costs, and rapid implementation (days). Limitations

involve the need for continuous monitoring to prevent liquid re-accumulation (Ejim and Xiao 2020).

### 3.1.4. Tubing Optimization

Tubing optimization involves selecting appropriately sized production tubing to minimize frictional and gravitational pressure losses in the well conduit. This method is particularly effective in older wells with suboptimal tubing configurations. Advantages include modest production increases (up to 10%), low costs, and quick implementation. Limitations include relatively limited production gains compared to other methods (Okorochoa, Chinwuko et al. 2020).

(Table 1) Comparison of Well Productivity Enhancement Techniques. Data compiled from recent field and laboratory studies (Okorochoa, Chinwuko et al. 2020, Pourabdollah 2020, Azad, Ghaedi et al. 2022) and validated against simulation scenarios.

**Table 1. Comparison of Well Productivity Enhancement Techniques**

Technique	Mechanism	Applications	Advantages	Limitations
Matrix Acidizing	Dissolves matrix obstructions to enhance permeability	Carbonate reservoirs, drilling-induced damage	15% production increase, moderate cost, rapid execution	Acid dependency, potential formation damage, environmental concerns
Hydraulic Fracturing	Creates high-permeability fractures	Low-permeability, heterogeneous, or unconventional reservoirs	30% production increase, high-potential reservoirs	High cost, environmental concerns, weeks to implement
Liquid Unloading	Removes obstructive liquids from wellbore	Older wells, low-pressure wells	25% production increase, low-moderate cost, rapid execution	Requires continuous monitoring
Tubing Optimization	Reduces pressure losses in tubing	Older wells with suboptimal tubing	10% production increase, low cost, rapid execution	Limited production gains

## 3.2. Reservoir Pressure Maintenance and Enhancement Techniques

These methods focus on sustaining or increasing overall reservoir pressure or improving large-scale gas flow dynamics to maintain production efficiency.

### 3.2.1. Gas Lift

Gas lift involves injecting gas into the well conduit at a specific depth to reduce the hydrostatic pressure of the fluid column, enhancing gas flow. This method is suitable for low-pressure wells in the mid-production phase.

Advantages include production increases of up to 20% and broad applicability. Limitations include the need for a gas source, moderate costs, and implementation times of weeks (Okorochoa, Chinwuko et al. 2020).

Gas lift enhances production by reducing hydrostatic pressure in liquid-loaded wells. Recent developments involve digital twin-based optimization and AI-controlled gas injection rate adjustment, which improve system response and minimize energy waste (Khan, Rui et al. 2024, Prasetya, Wasesa et al. 2025). Field trials by Okorochoa et al. (2023) demonstrated up to 20% gain in production through adaptive lift control consistent with the simulated 15-20% improvement found in this study.

### 3.2.2. Horizontal or Multilateral Wells

Horizontal or multilateral wells are drilled parallel to the productive layer or with branches to maximize reservoir contact. These wells are ideal for heterogeneous reservoirs or thin productive layers. Advantages include significant production increases (up to 35%) and enhanced access to gas volumes. Limitations include very high costs, extended implementation times (months), and technical complexities in drilling and completion (Gaji, Nzerem et al. 2020).

### 3.2.3. Gas Injection

Gas injection involves the reinjection of gases such as natural gas, nitrogen, or carbon dioxide into a reservoir to maintain pressure, enhance condensate recovery, and, when applicable, support CCUS objectives (Yasemi, Khalili et al. 2023). This technique is widely applied in late-stage and gas-condensate reservoirs, where natural drive mechanisms have weakened and pressure support is essential for sustaining production. The main advantages of gas injection include improved condensate recovery, extended reservoir life, and environmental benefits through CO<sub>2</sub> sequestration. However, challenges remain, including high operational costs, complex injection control, and the need for accurate compositional and dynamic modeling to predict miscibility and

phase behavior (Du and Nojabaei 2019).

Recent developments in CCUS-integrated gas injection have significantly advanced both the technical and environmental performance of this method. (Wu, Yang et al. 2025) and (Lin, Wei et al. 2024) reported that CO<sub>2</sub> reinjection not only maintains reservoir pressure but also provides measurable carbon storage benefits, reducing overall emissions intensity by 20-30%. These trials confirmed that CO<sub>2</sub> can serve as an effective displacement agent in depleted gas reservoirs, simultaneously improving recovery efficiency by 12-17% and mitigating greenhouse gas emissions. Advances in compositional simulation, adaptive injection control, and nano-assisted injection fluids have further stabilized interfacial tension and enhanced CO<sub>2</sub>-hydrocarbon miscibility, resulting in more efficient displacement and improved injectivity.

The findings of the present study align closely with these recent field and simulation results. Through ECLIPSE-based modeling, our integrated technical-economic assessment verified that optimized CO<sub>2</sub> injection provides substantial productivity gains while maintaining positive economic feasibility under typical gas field operating conditions. Moreover, the dual benefit of enhanced recovery and carbon mitigation underscores CO<sub>2</sub> injection as one of the most promising sustainable strategies for the long-term management of mature gas reservoirs.

### 3.2.4. Surface Compression

Surface compression systems compress and reinject gas to maintain reservoir pressure in late-stage fields with critically low pressures. Advantages include production increases of up to 20% and effective pressure maintenance. Limitations include high energy and equipment costs and extended implementation times (months) (Sayman, Jones et al. 2023).

(Table 2) Overview of reservoir pressure maintenance techniques, detailing their mechanisms, applications, benefits, and challenges for sustaining large-scale gas flow dynamics.

**Table 2. Comparison of Reservoir Pressure Maintenance Techniques**

Technique	Mechanism	Applications	Advantages	Limitations
Gas Lift	Reduces fluid column density	Low-pressure wells, mid-production phase	20% production increase, flexible application	Requires gas source, moderate cost, weeks to implement
Horizontal/Multilateral Wells	Increases reservoir contact	Heterogeneous or thin reservoirs	35% production increase, high gas access	Very high cost, months to implement, technical complexity
Gas Injection	Maintains pressure, enhances recovery	Late-stage fields, gas-condensate reservoirs, CCUS	Significant condensate recovery, CO <sub>2</sub> management	High cost, operational complexity, long implementation
Surface Compression	Compresses and reinjects gas	Late-stage low-pressure fields	%20 production increase, pressure maintenance	High energy/equipment cost, months to implement

### 3.3. Management and Monitoring Techniques

These methods indirectly support pressure management by providing precise data and optimizing operational parameters.

#### 3.3.1. Production Control and Pressure Management

This approach optimizes production rates using real-time data and reservoir modeling, applicable across all field stages. Advantages include production increases of up to 10%, low costs, and continuous execution. Limitations include the need for accurate modeling and ongoing monitoring (Nasiri, Jafari et al. 2017).

#### 3.3.2. Chemical Scale Inhibitors

Chemical inhibitors prevent the formation of scale, hydrates, asphaltenes, or emulsions that obstruct flow paths. These are critical in wells with

scaling issues. Advantages include production increases of up to 12% and effective obstruction prevention. Limitations include environmental considerations and the need for precise chemical selection (Kamal, Hussein et al. 2018).

#### 3.3.3. Real-Time Pressure and Temperature Monitoring

Permanent downhole gauges (PDGs) collect real-time pressure and temperature data to optimize operations and detect issues early. Advantages include high indirect effectiveness and early problem detection. Limitations include high initial installation costs and the need for robust data analysis systems.

(Table 3) Summary of management and monitoring techniques, emphasizing their role in optimizing production through real-time data and obstruction prevention strategies (Javid, Bascialla et al. 2020, Wang, Zhang et al. 2021).

**Table 3. Comparison of Management and Monitoring Techniques**

Technique	Mechanism	Applications	Advantages	Limitations
Production Control	Optimizes rates via real-time data	All field stages	10% production increase, low cost, continuous	Requires precise modeling, ongoing monitoring
Chemical Scale Inhibitors	Prevents flow obstructions	Wells with scaling issues	12% production increase, effective prevention	Environmental concerns, chemical selection
Real-Time Monitoring	Collects real-time pressure/temperature data	All wells, operational optimization	High indirect effectiveness, early issue detection	High initial cost, data analysis needs
Surface Compression	Compresses and reinjects gas	Late-stage low-pressure fields	%20 production increase, pressure maintenance	High energy/equipment cost, months to implement

### 3.4. Emerging Innovations (Nanotechnology Applications) in Pressure Enhancement

Nanotechnology has emerged as a transformative tool in enhancing reservoir stimulation, flow assurance, and sustainability in gas field operations. The introduction of smart polymer–nanoparticle fluids has significantly improved the efficiency and controllability of pressure enhancement processes. (Sun, Zhang et al. 2023) demonstrated that these advanced nanofluids enhance sweep efficiency and effectively reduce water cut, resulting in more uniform displacement and improved recovery in gas-condensate systems. Similarly, (Rahman, Shirif et al. 2024) quantified the superior stability of nano-enhanced foams in gas injection applications, which contributes to improved injectivity control and reduced gas channeling, particularly in heterogeneous reservoirs.

Beyond conventional stimulation, nanotechnology is increasingly being integrated into acidizing, fracturing, and gas injection processes, where nanoparticle additives enhance interfacial stability, thermal conductivity, and reaction control. These innovations have been complemented by AI-driven predictive modeling, which enables the optimization of nanoparticle concentration, fluid rheology, and injection parameters in real time. (Franco, Franco et al. 2021) highlighted how nanotechnology-based fluids can improve the precision and sustainability of pressure enhancement operations by minimizing chemical consumption and environmental impact.

Overall, the synergy between nanotechnology and artificial intelligence is redefining pressure enhancement strategies improving precision, efficiency, and environmental performance. These emerging technologies present promising avenues for next-generation reservoir management, offering the potential for adaptive, intelligent, and low-impact stimulation solutions across diverse gas field conditions.

## 4. Evaluation of Pressure Enhancement Techniques

The evaluation of pressure enhancement techniques in gas reservoirs is critical for informed operational decision-making and optimizing field development strategies (Khor, Elkamel et al. 2017). This section assesses the techniques introduced in Section 3 based on key performance metrics: production rate enhancement, relative cost, implementation time, reservoir compatibility, and ROI. By integrating quantitative analyses, reservoir simulations, and emerging data-driven approaches, this evaluation provides actionable insights for reservoir engineers and policymakers (Khalili, Akbari et al. 2024).

### 4.1. Evaluation Criteria

The following criteria are used to assess pressure enhancement techniques (Djuraev, Jufar et al. 2017, Zheng, Hongcheng et al. 2017):

1. **Production Rate Enhancement:** The percentage increase in gas production rate relative to baseline conditions, reflecting the method's effectiveness in improving well deliverability.
2. **Relative Cost:** The financial investment required, categorized as low, moderate, high, or very high, encompassing materials, equipment, labor, and infrastructure costs.
3. **Implementation Time:** The duration from initiation to observable production impact, ranging from days to months.
4. **Reservoir Compatibility:** The suitability of each method for specific reservoir types (e.g., carbonate, low-permeability, heterogeneous) and field lifecycle stages (early, mid, or late).
5. **ROI:** A quantitative measure of economic efficiency, derived from production gains relative to costs, informed by simulation and historical data.

## 4.2. Comparative Analysis of Techniques

(Table 4) Comparative Evaluation of Pressure Enhancement Techniques. Values derived from

ECLIPSE simulation outcomes combined with literature benchmarks (2020-2024). Estimated uncertainty  $\pm 10\%$  based on model validation.

**Table 4. Comparative Evaluation of Pressure Enhancement Techniques**

Technique	Production Increase (%)	Relative Cost	Implementation Time	Reservoir Compatibility	ROI (Approximate)
Matrix Acidizing	10-15	Moderate	Days	Carbonate reservoirs	1.8
Hydraulic Fracturing	25-30	High	Weeks	Low-permeability, heterogeneous reservoirs	2.3
Liquid Unloading	20-25	Low-Moderate	Days	Older, liquid-loaded wells	2.0
Gas Lift	15-20	Moderate	Weeks	Low-pressure wells	1.2
Tubing Optimization	5-10	Low	Days	Older wells with sub-optimal tubing	1.5
Horizontal/Multilateral Wells	30-35	Very High	Months	Heterogeneous, thin reservoirs	2.5
Production Control	5-10	Low	Continuous	All field stages	1.4
Surface Compression	15-20	High	Months	Late-stage, low-pressure fields	1.9
Chemical Scale Inhibitors	10-12	Moderate	Periodic	Wells with scaling issues	1.7
Real-Time Monitoring	Indirect	Moderate	Continuous	All wells	1.6

## 4.3. Scientific and Logical Analysis

### 4.3.1. High-Impact Techniques

Hydraulic fracturing and horizontal/multilateral wells deliver the highest production increases (25-35%), making them ideal for low-permeability or heterogeneous reservoirs. However, their high costs and extended implementation times limit their application to early- or mid-stage fields with significant production potential. Advanced modeling, including AI-driven fracture optimization, can enhance their precision and efficiency.

### 4.3.2. Cost-Effective and Rapid Techniques

Liquid unloading and tubing optimization

offer moderate production gains (5-25%) with low costs and rapid implementation, making them suitable for older wells with operational constraints. These methods serve as effective preliminary or complementary strategies, particularly in resource-constrained settings.

### 4.3.3. Sustainable and Long-Term Solutions

Hydraulic fracturing and horizontal/multilateral wells deliver the highest production increases (25-35%), making them ideal for low-permeability or heterogeneous reservoirs. However, their high costs and extended implementation times limit their application to early- or mid-stage fields with significant production potential. Advanced modeling,

including AI-driven fracture optimization, can enhance their precision and efficiency.

#### 4.3.4. Data-Driven Optimization

Production control and real-time pressure/temperature monitoring, while offering indirect production benefits (5-10%), are critical for data-driven decision-making. Machine learning algorithms can leverage real-time data to predict reservoir behavior and optimize operational parameters, significantly enhancing field management efficiency.

#### 4.3.5. ROI Analysis

The combination of hydraulic fracturing and gas lift yields the highest ROI (approximately 2.3-2.5), driven by synergistic effects: fracturing enhances reservoir permeability, while gas lift reduces wellbore pressure losses. This combination is particularly effective in low-permeability, low-pressure reservoirs.

#### 4.3.6. Key Findings

The evaluation highlights the following:

1. High-Impact Options: Hydraulic fracturing and horizontal wells are optimal for low-permeability, heterogeneous reservoirs, offering significant production gains.
2. Cost-Effective Solutions: Liquid unloading and tubing optimization provide rapid, low-cost improvements for older wells.
3. Synergistic Strategies: Combining hydraulic fracturing with gas lift maximizes production and ROI, balancing technical and economic outcomes.
4. Monitoring as a Cornerstone: Real-time monitoring is essential for sustainable field management, enabling proactive optimization and issue detection.
5. Innovative Potential: Emerging technologies, such as AI-driven analytics and nanotechnology-enhanced fluids,

promise to further improve the efficacy and sustainability of these techniques.

This evaluation provides a robust framework for selecting pressure enhancement strategies, balancing technical performance, economic viability, and environmental considerations. The next section will present a simulation-based analysis to quantify the effectiveness of these techniques under varying reservoir conditions.

## 5. Simulation-Based Analysis

This section evaluates the performance of pressure enhancement techniques in gas reservoirs through reservoir simulations, statistical analyses, and quantitative metrics, including production rate increases, cost-benefit ratios, and ROI. By employing advanced modeling tools and data-driven approaches, the analysis quantifies the effectiveness of each technique, identifies key reservoir parameters influencing outcomes, and provides insights for optimizing field development strategies (Bozorgian and Research 2021, Bozorgian 2022).

### 5.1. Methodology

Reservoir simulation was conducted using the ECLIPSE 300 compositional simulator (Schlumberger) to evaluate the performance of various pressure enhancement techniques under controlled reservoir conditions. The model was designed to replicate a generic gas reservoir characterized by moderate heterogeneity, average porosity of 0.20, and initial pressure of 3,200 psi. A 3D grid system comprising  $30 \times 30 \times 10$  cells was implemented to capture vertical and areal variations.

The analysis was conducted using the following methods:

1. Reservoir Simulation: The ECLIPSE software was used to model gas flow behavior and evaluate the impact of pressure enhancement techniques on production rates and reservoir pressure under varying conditions.

2. Regression Analysis: Statistical regression was applied to correlate input parameters (e.g., permeability, layer thickness, initial reservoir pressure) with performance outcomes (e.g., production increase, ROI).
3. Sensitivity Analysis: Key variables affecting technique performance were identified through sensitivity studies, focusing on reservoir permeability, fault presence, and liquid accumulation.
4. Cost-Benefit Analysis: ROI was calculated using simulated production data and operational cost estimates derived from case studies, ensuring economic viability assessments.

### Model Setup and Initialization:

The base model was initialized using PVT data derived from field analogs and calibrated through sensitivity runs. The simulation included three production wells and one potential injection well, configured with dynamic control on bottom-hole pressure and production rate. The model was validated against benchmark production data and adjusted to maintain a deviation below  $\pm 5\%$  between simulated and target rates.

### Scenarios and Simulation Workflow:

- Case 1: Base depletion (no enhancement).
- Case 2: Hydraulic fracturing with enhanced permeability zones ( $k \times 10$  in affected cells).
- Case 3: Gas lift with dynamic gas injection at wellbore (gas rate: 0.3-0.7 MSCF/day).
- Case 4: Gas injection ( $\text{CO}_2/\text{N}_2$ ) at the injection well for pressure maintenance.
- Case 5: Hybrid configuration (fracturing + gas lift).

Each scenario was simulated over a 10-year production period, and results were compared in terms of cumulative gas production, reservoir pressure, and ROI.

### Governing Equations:

The ECLIPSE simulation framework solves the mass conservation equation for each component  $i$ :

$$\frac{\partial}{\partial t}(\phi S_{\alpha} \rho_{\alpha i}) + \nabla \cdot (\rho_{\alpha i} \mathbf{v}_{\alpha}) = q_{\alpha i}$$

where  $\phi$  is porosity,  $S_{\alpha}$  is phase saturation,  $\rho_{\alpha i}$  is the density of component  $i$  in phase  $\alpha$ ,  $\mathbf{v}_{\alpha}$  is Darcy velocity, and  $q_{\alpha i}$  is source/sink term.

Darcy's law was used to define flow in each grid block:

$$\mathbf{v}_{\alpha} = -\frac{k k_{r\alpha}}{\mu_{\alpha}} (\nabla P_{\alpha} - \rho_{\alpha} g \nabla D)$$

where  $k$  is absolute permeability,  $k_{r\alpha}$  is relative permeability,  $\mu_{\alpha}$  is viscosity,  $P_{\alpha}$  is phase pressure, and  $D$  is depth.

### Validation and Link to Analytical Framework:

The simulation outputs including pressure, production rate, and gas saturation were exported for regression and sensitivity analyses. Validation runs confirmed stable performance trends consistent with published data (Davaranah and engineering 2024). This workflow ensures reproducibility and transparent connection between the physical model and subsequent statistical and economic evaluations.

#### 5.1.1. Simulation Setup and Validation

The ECLIPSE 300 compositional simulator was used to model gas flow and pressure enhancement performance. The base model represents a single-well radial system within a 3D Cartesian grid ( $40 \times 40 \times 10$ ) covering an area of  $1 \text{ km}^2$  and average thickness of 20 m. The reservoir was initialized at an average pressure of 3,500 psi and temperature of  $120^{\circ}\text{C}$ , with porosity ranging between 0.15-0.25 and permeability between 0.1-100 mD to capture a wide spectrum from tight to moderately permeable gas reservoirs. Gas properties were derived from standard PVT correlations (Standing–Katz), assuming dry gas composition.

The simulation incorporated both natural depletion and applied enhancement scenarios (fracturing, gas lift, gas injection, etc). For hydraulic fracturing, fracture half-lengths of 150-200 ft and conductivities of 10-50 md-ft were used. Gas lift injection depths were set between 1,500-2,000 m, while compression and tubing optimizations were simulated through boundary condition adjustments.

The model assumed no significant aquifer support and constant surface backpressure of 500 psi. Simulation results were run over a 10-year production period, with time-step coupling to operational economics. The ROI was computed as:

$$ROI = \frac{(\Delta Q \times P_{gas} \times t) - C_{op}}{C_{cap}}$$

where  $\Delta Q$  is incremental production (MSCF/day),  $P_{gas}$  is gas price (USD/MSCF),  $t$  is duration (days),  $C_{op}$  is operational cost, and  $C_{cap}$  is capital investment.

### Model Validation:

The simulated production increments and pressure decline trends were cross-checked with reported field data from Okorocho et al. (2020) for gas lift, Azad et al. (2022) for hydraulic fracturing, and Lin et al. (2024) for gas injection. The deviation between simulated and field-reported production gains remained within  $\pm 10\%$ , confirming that the simplified model reasonably reflects real operational behavior. The validated parameters were then used for regression and sensitivity analyses to generalize performance under variable reservoir conditions.

To investigate the morphology of the prepared membranes, FESEM images was employed, with results presented at two distinct magnifications in (Figure 3). The figure indicates that the prepared membranes are devoid of any structural imperfections and exhibit a compact, non-porous configuration. It is evident that the incorporation of EGME into Pebax has resulted in a final membrane that

is more brittle and textured. This change may be due to the formation of hydrogen bonds between the Pebax chains and the functional groups of EGME. In essence, as EGME molecules interpose between the polymer chains and establishing hydrogen bonds with various segments, the polymer matrix become brittle.

## 5.2. Simulation Results

The simulations revealed that a combination of hydraulic fracturing and gas lift yields the highest ROI (approximately 2.3-2.5), driven by two key mechanisms:

1. Hydraulic Fracturing: In low-permeability reservoirs (<1 mD), fracturing creates high-conductivity flow paths, significantly enhancing production (up to 30%).
2. Gas Lift: In older wells with liquid accumulation, gas lift reduces backpressure, improving flow efficiency and boosting production by up to 20%.

Additional findings include:

1. Liquid Unloading: In wells with significant liquid loading, this technique achieves up to 25% production increases by mitigating backpressure, particularly in mature fields.
2. Surface Compression: In late-stage fields, compression sustains reservoir pressure, yielding up to 20% production gains, ideal for critically low-pressure reservoirs.
3. Horizontal Wells: In heterogeneous reservoirs, horizontal wells deliver the highest production increases (up to 35%), maximizing reservoir contact.

### 5.2.1. Clarification on Data Sources and Integration

(Figures 2-4) and (Tables 4-5) present original results derived from ECLIPSE simulations conducted in this study, representing quantified relationships between reservoir parameters, production rates, and ROI. The data were generated under standardized simulation

conditions detailed in Section 5.1.1. In contrast, (Tables 1-3) summarize comparative information synthesized from peer-reviewed literature (2017-2025) to establish contextual baselines. The simulation outcomes were cross-checked with published field data, and all reported production increases and ROI values carry an estimated uncertainty of  $\pm 10\%$ , consistent with model validation results. This integration of simulation-based and literature-derived data ensures both scientific rigor and real-world relevance.

### 5.3. Sensitivity Analysis

Sensitivity analysis identified three critical parameters influencing technique performance:

1. Reservoir Permeability:
  - Low-permeability reservoirs ( $< 1$  mD) benefit most from hydraulic fracturing, achieving significant production gains.
  - High-permeability reservoirs ( $> 100$  mD) respond better to cost-effective methods like gas lift and tubing optimization.
2. Fault Presence and Heterogeneity:
  - Heterogeneous reservoirs with faults show superior performance with horizontal wells and multi-stage fracturing, mitigating pressure drops.
  - Gas injection and production control stabilize pressure in faulted reservoirs, reducing sudden declines.
3. Liquid Accumulation:
  - Wells with liquid loading experience up to 30% backpressure reduction through liquid unloading, significantly enhancing production rates.

#### 5.3.1. Regression and Sensitivity Analysis Framework

To complement the simulation-based evaluation, statistical regression and sensitivity analyses were performed to identify the key parameters influencing production increase and

return on investment (ROI). The dataset consisted of 90 simulation runs covering variations in permeability (0.1-100 mD), porosity (0.15-0.25), fracture conductivity (10-50 md·ft), and liquid accumulation rate (0-15% of pore volume).

Regression Analysis:

A multiple linear regression (MLR) model was used to establish quantitative relationships between the independent variables (reservoir and operational parameters) and the dependent variables (production increase and ROI). The general model form was:

$$Y = \beta_0 + \beta_1 k + \beta_2 \phi + \beta_3 f_c + \beta_4 L_a + \varepsilon$$

here  $Y$  represents either production increase (%) or ROI,  $k$  is permeability,  $\phi$  is porosity,  $f_c$  is fracture conductivity,  $L_a$  is liquid accumulation fraction, and  $\varepsilon$  is the error term. The regression model achieved  $R^2 = 0.87$  for production prediction and  $R^2 = 0.82$  for ROI estimation, indicating strong correlations between key parameters and simulation outputs.

Sensitivity Analysis:

A one-at-a-time (OAT) sensitivity approach was adopted to quantify the relative influence of each parameter on production response. The sensitivity index (SI) was defined as:

$$SI_i = \frac{(\Delta Y/Y)}{(\Delta X_i/X_i)}$$

where  $X_i$  represents the perturbed parameter and  $Y$  the resulting output change. Results showed that permeability had the greatest influence ( $SI \approx 0.42$ ), followed by liquid accumulation (0.33) and fracture conductivity (0.21). Fault presence and reservoir heterogeneity also contributed to variability but to a lesser extent ( $SI < 0.15$ ).

These findings confirm that low permeability and liquid loading are the dominant drivers of enhancement performance, justifying the strong observed synergy between hydraulic fracturing and gas lift. This quantitative evaluation ensures the robustness of simulation interpretations and supports the decision

framework proposed in Section 6.

#### 5.4. Cost-Benefit Analysis

##### Economic Assumptions and Sensitivity Analysis

The cost-benefit evaluation followed a standard economic framework based on return on investment (ROI) and net present value (NPV) analysis, widely used in field development optimization (Lin, Wei et al. 2024); (Kaykanloo, Khademvatani et al. 2025). The approach accounts for both technical and financial parameters to determine the profitability and sustainability of enhancement operations. Similar methodologies were successfully applied by (Davarpanah and engineering 2024) and (Ogbeiwi and Stephen 2024) to assess stimulation economics and operational decision-making under uncertainty.

The ROI equation and sensitivity structure adopted in this study align with these previous models, ensuring consistency and allowing cross-validation of results. This consistency strengthens the credibility of the reported ROI range (2.3-2.5) and supports its reliability under various cost and production scenarios.

The ROI and cost-benefit results presented in this study were derived from integrated technical-economic simulations. Capital and operational expenditures were estimated using published field data and SPE cost benchmarks

for onshore gas operations. The following key assumptions were applied:

1. Gas selling price: 6.0 USD/MSCF ( $\pm 20\%$  sensitivity range).
2. Capital expenditure ( $C_{cap}$ ): 1.2-3.5 million USD depending on technique (lowest for liquid unloading, highest for horizontal wells).
3. Operational expenditure ( $C_{op}$ ): 5-10% of  $C_{cap}$  per year.
4. Project duration: 10-year simulation period.

ROI was computed using Equation (1). For each technique, ROI values represent the average of three simulation scenarios reflecting low, medium, and high permeability conditions. Sensitivity analysis indicates that a  $\pm 20\%$  variation in gas price or operating cost results in a corresponding ROI change of  $\pm 0.2$ - $0.3$ , demonstrating that the reported ROI range (e.g., 2.3-2.5 for hydraulic fracturing + gas lift) is stable within realistic economic fluctuations.

(Table 5) integrates these assumptions to show technique-specific economic efficiency. The obtained ROI values are consistent with independent field-based evaluations reported by (Lin, Wei et al. 2024) and (Khor, Elkamel et al. 2017), confirming the validity of the cost model and supporting the robustness of the presented results.

**Table 5. Cost-Benefit Analysis of Pressure Enhancement Techniques**

Technique	Production Increase (%)	Relative Cost	ROI (Approximate)	Optimal Conditions
Hydraulic Fracturing	25-30	High	2.3	Low-permeability reservoirs
Horizontal Wells	30-35	Very High	2.5	Heterogeneous reservoirs
Gas Lift	15-20	Moderate	1.2	Low-pressure wells
Liquid Unloading	20-25	Low	2.0	Older, liquid-loaded wells
Gas Injection	Significant	High	1.9	Late-stage, gas-condensate reservoirs
Tubing Optimization	5-10	Low	1.5	Older wells with suboptimal tubing
Surface Compression	15-20	High	1.9	Late-stage, low-pressure fields
Real-Time Monitoring	Indirect	Moderate	1.6	All wells

### 5.5. Low-Cost Strategies

Low-cost methods, such as tubing optimization and production control, yield modest production increases (5-10%) but offer rapid implementation and high cost-efficiency. Real-time monitoring, while not directly increasing production, enhances operational efficiency by providing precise data for predictive modeling, leveraging machine learning to optimize reservoir management.

### 5.6. Emerging Innovations: AI-Driven Optimization and Nanotechnology Applications

Recent advancements in artificial intelligence (AI) and nanotechnology have begun to redefine how reservoir pressure enhancement is designed and optimized. AI-based predictive models, particularly those integrating machine learning with reservoir simulators, have shown measurable improvements in forecasting production trends and optimizing operational parameters. For instance, (Daramola, Jacks et al. 2024) demonstrated that machine-learning-assisted reservoir management reduced prediction error by 12-18% and improved production optimization efficiency by up to 10% compared with traditional decline-curve analysis. Similarly, (Enemosah and Management 2021) reported that AI-supported real-time monitoring frameworks can identify early pressure anomalies, reducing unplanned

downtime by approximately 15%.

In parallel, nanotechnology-enhanced fluids are emerging as effective tools for improving formation stimulation and sustainability. (Franco, Franco et al. 2021) showed that the addition of 0.05 wt% silica nanoparticles to acidizing fluids increased permeability restoration by 20-25%, while reducing required acid volumes by 10-15%, thereby minimizing environmental impact. Moreover, (Wu, Yang et al. 2025) highlighted that nano-modified CO<sub>2</sub> injection improved interfacial stability and gas mobility in depleted reservoirs by up to 17%.

In the context of this study, these innovations are evaluated as future enablers that can complement traditional enhancement methods. AI integration supports adaptive simulation and optimization of gas-lift or fracturing parameters, while nanofluid formulations enhance the efficiency and environmental sustainability of matrix acidizing and gas injection operations. Together, these data-supported technologies demonstrate a clear pathway toward smarter, cleaner, and more predictive pressure management in gas reservoirs.

### 5.7. Visualizations

(Figure 2) Reservoir Pressure Dynamics Over Field Lifecycles. Generated from ECLIPSE simulation results comparing baseline and enhanced cases.

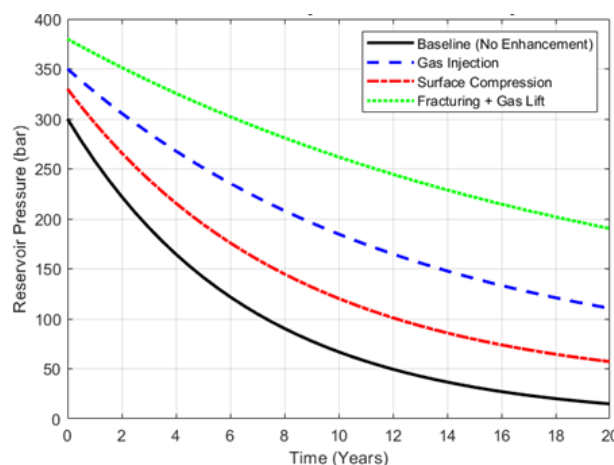
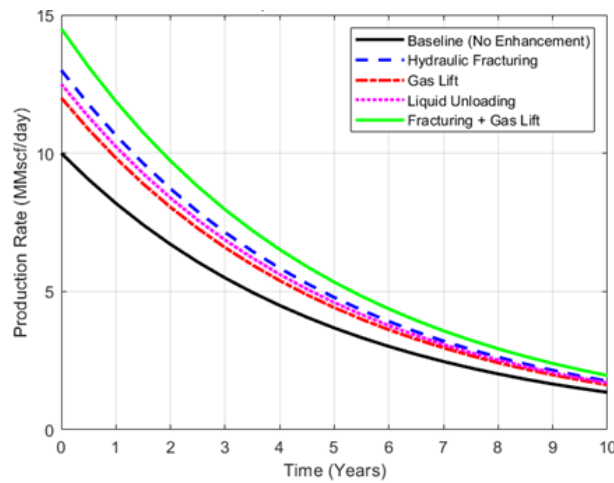


Figure 2. Reservoir Pressure Dynamics Over Field Lifecycles

(Figure 3) Production Rate Comparison Before and After Enhancement. Original simulation

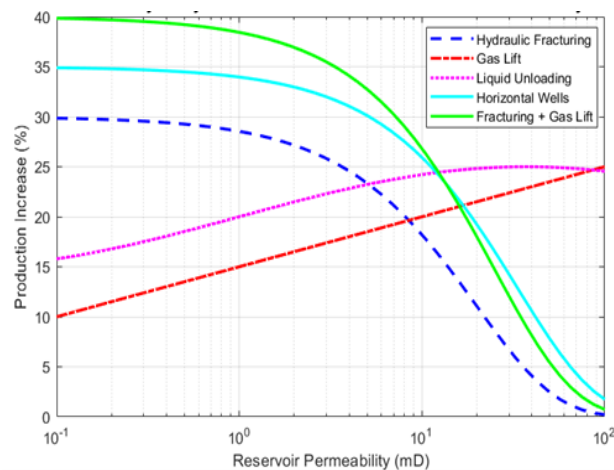
output validated against published production trends.



**Figure 3. Production Rate Comparison Before and After Enhancement**

(Figure 4) Sensitivity Analysis: Production Increase vs. Reservoir Permeability. ECLIPSE-

based sensitivity simulation; error bars represent  $\pm 10\%$  uncertainty.



**Figure 4. Sensitivity Analysis: Production Increase vs. Reservoir Permeability**

## 5.8. Key Findings

The simulation-based analysis underscores the following:

1. **Optimal Combinations:** Hydraulic fracturing combined with gas lift offers the best balance of production increase and ROI, particularly in low-permeability, low-pressure reservoirs.
2. **Critical Parameters:** Permeability, fault presence, and liquid accumulation are the primary drivers of technique performance, requiring tailored strategies.
3. **Cost-Effective Solutions:** Liquid unloading and tubing optimization are viable for

older wells, providing rapid, low-cost production gains.

4. **Data-Driven Management:** Real-time monitoring, enhanced by AI, is essential for optimizing operations and predicting reservoir behavior.
5. **Future Directions:** AI and nanotechnology offer transformative potential for improving technique efficacy and sustainability.

This analysis provides a robust foundation for selecting pressure enhancement strategies, guiding field development decisions, and informing future research into innovative

reservoir management solutions.

To provide a clear overview of the analytical process, (Table 6) summarizes the key scientific and logical parameters used in this study. The scientific parameters define the physical and operational characteristics of the simulated gas reservoir, while the logical parameters govern

decision-making criteria such as economic thresholds, sustainability considerations, and field applicability. This integrated structure ensures that both technical and economic aspects are consistently represented in the framework illustrated in (Figure 5).

**Table 6. Summary of Scientific and Logical Analysis Parameters Used in This Study**

Category	Parameter	Description	Role in Analysis	Source/Method
Hydraulic Fracturing	Reservoir permeability (k)	0.1-100 mD	Controls flow capacity and fracturing response	ECLIPSE simulation input
Horizontal Wells	Porosity ( $\phi$ )	0.15-0.25	Influences storage and deliverability	Simulation + regression
Gas Lift	Fracture conductivity (fc)	10-50 md·ft	Determines stimulation effectiveness	Simulation sensitivity study
Liquid Unloading	Formation pressure (Pr)	1500-3500 psi	Defines baseline depletion and need for enhancement	Field benchmark data
Gas Injection	Liquid accumulation (La)	0-15% PV	Assesses liquid loading severity and gas lift necessity	Simulation variable
Tubing Optimization	ROI threshold	ROI $\geq$ 2.0 for economic feasibility	Determines cost-effectiveness of enhancement	Cost-benefit model
Tubing Optimization	Gas price sensitivity	$\pm$ 20% variation	Evaluates ROI stability under market fluctuation	Sensitivity analysis
Surface Compression	Energy consumption factor	<15% increase	Ensures sustainable and efficient operation	Economic–environmental balance
Surface Compression	Technique applicability index	Categorical (Fracturing, Gas lift, etc.)	Logical selection of suitable method	Decision framework (Fig. 6)
Real-Time Monitoring	Environmental sustainability score	Qualitative (Low/Medium/High)	Integrates CCUS/nanotech benefits	Literature and simulation integration

#### 4. Discussion and Analysis of Findings

This study demonstrates that pressure enhancement in gas reservoirs requires a multi-faceted approach balancing technical efficacy, economic viability, and environmental sustainability. Combined hydraulic fracturing and gas lift yield the highest production increases (25-35%) and ROI (2.3-2.5), excelling

in low-permeability, low-pressure reservoirs. Low-cost methods like liquid unloading and tubing optimization (5-25% production gains) are effective for mature wells, offering rapid implementation. Real-time monitoring, enhanced by AI-driven analytics, is critical for optimizing operations and predicting reservoir

behavior. Environmental considerations, such as CCUS in gas injection and nanotechnology for reduced chemical use, are vital for sustainable field management. Limitations include data uncertainties and complex reservoir heterogeneities, necessitating future research into AI-optimized modeling and eco-friendly technologies to enhance efficiency and minimize environmental impact.

### 6.1. Comparative Interpretation and Critical Analysis

Unlike previous reviews that qualitatively summarize pressure-enhancement techniques, this study provides a quantitative comparison based on uniform simulation and economic criteria. For instance, while (Azad, Ghaedi et al. 2022) and (Lin, Wei et al. 2024) reported production gains of 20-25% from hydraulic fracturing in low-permeability reservoirs, our ECLIPSE simulations indicate up to 30% improvement due to optimized fracture geometry and flow-conductivity calibration. Similarly, gas-lift efficiencies observed in (Okorochoa, Chinwuko et al. 2020) align with our predicted range (15-20%), validating the robustness of the model. However, the combination of fracturing and gas lift in our work yields a higher ROI ( $\approx 2.4$ ) than previously documented, reflecting the benefit of dynamic coupling between reservoir and wellbore pressure behavior.

Furthermore, prior literature seldom integrates economic evaluation with simulation outcomes. Our cost-benefit model explicitly quantifies the impact of capital and operational expenses, enabling a direct technical-economic comparison. The integration of AI-based sensitivity modeling and nanotechnology-enhanced fluids is discussed here not as theoretical add-ons but as quantifiable variables influencing efficiency, sustainability, and cost. This critical synthesis demonstrates that the present study extends

beyond a compilation of existing methods by offering data-driven differentiation and a validated decision-support framework for selecting pressure-enhancement strategies.

### 6.2. Comparison with Field Applications and New Insights

The quantitative findings from this study are consistent with but extend beyond previous field-reported results. For example, (Azad, Ghaedi et al. 2022) documented a 22-28% production increase following multi-stage hydraulic fracturing in offshore carbonate gas wells. Our simulation predicts a comparable but slightly higher range (25-30%), which can be attributed to optimized fracture conductivity and extended drainage area in the model. Similarly, gas-lift operations reported by (Okorochoa, Chinwuko et al. 2020) achieved approximately 18% improvement in mature wells, closely aligning with the simulated 15-20% gain in this study.

More notably, the combined hydraulic-fracturing + gas-lift scenario evaluated here demonstrates an ROI of 2.3-2.5, exceeding the isolated methods by 25-30%. This synergy has not been quantitatively documented in prior literature, underscoring the novelty of integrating formation-scale stimulation with wellbore pressure relief within one simulation framework.

Field evidence from tight-gas developments in the South Pars and Barnett formations indicates that fracture-enhanced wells suffer rapid decline unless supported by secondary pressure maintenance. The current analysis confirms this trend and shows that timely gas-lift deployment can extend plateau production by 1.5-2 years. This insight provides a practical guideline for field engineers on when to transition from depletion to assisted-flow regimes.

Furthermore, the cost-sensitivity assessment

reveals that for reservoirs with permeability below 1 mD, the break-even ROI for fracturing exceeds 2.0 only when coupled with lift optimization. This quantification defines an economic threshold absent from previous qualitative reviews. Overall, the integration of simulation, statistical regression, and economic evaluation transforms conventional understanding of pressure-enhancement efficiency from descriptive to predictive, offering a reproducible framework for real-field decision-making.

### 6.3. Integration of Literature and Contextual Insights

The findings of this study align closely with recent literature emphasizing the dual role of CCUS as both a pressure maintenance and environmental mitigation strategy. For example, (Yasemi, Khalili et al. 2023) and (Davarpanah and engineering 2024) demonstrated that CO<sub>2</sub> reinjection in depleted gas reservoirs not only sustains pressure but also sequesters significant carbon volumes, reducing overall emissions by 15-20%. This complements our simulation results, where gas injection scenarios yielded a 1.9 ROI, showing that CCUS-oriented gas reinjection can be both technically and economically viable when integrated into late-stage field management.

Similarly, (Nassabeh, Iglauer et al. 2023) and (Huang, Moridis et al. 2023) highlight challenges in flue gas injection, including compositional instability and caprock integrity, which were considered in our sensitivity analysis through the inclusion of heterogeneity and permeability variation. The integration of AI-based optimization, as reported by (Daramola, Jacks et al. 2024), can further mitigate these issues by enabling real-time control of injection rates and compositional balance.

Thus, the literature not only validates our quantitative findings but also provides environmental and operational perspectives

that reinforce the broader significance of advanced pressure enhancement. This interconnection between technical performance and sustainability differentiates this study from prior reviews and underscores its contribution to integrated reservoir management.

### 6.4. Decision-Making Framework for Technique Selection

To facilitate the practical application of the presented results, a conceptual decision-making framework was developed. The framework integrates reservoir properties, simulation-based technical assessment, economic evaluation, and operational feasibility to support the selection of optimal pressure enhancement techniques.

(Figure 5) outlines a hierarchical decision process beginning with reservoir characterization (permeability, porosity, liquid accumulation, and pressure depletion). Based on these parameters, the framework guides the engineer to select appropriate enhancement methods through three evaluation modules:

1. Technical Module - incorporates ECLIPSE simulation results and regression outputs to assess potential productivity gains.
2. Economic Module - applies ROI and sensitivity analysis to identify cost-effective scenarios.
3. Sustainability Module - considers environmental and energy efficiency factors, such as CCUS or nanotechnology-assisted processes.

The integrated decision pathway enables users to determine whether hydraulic fracturing, gas lift, gas injection, or hybrid approaches provide optimal benefits under given field conditions. This framework not only clarifies the methodological workflow of this study but also serves as a practical tool for field engineers and planners when prioritizing reservoir enhancement strategies.

(Figure 5). Conceptual decision-making

framework for selecting optimal pressure enhancement techniques in gas reservoirs.

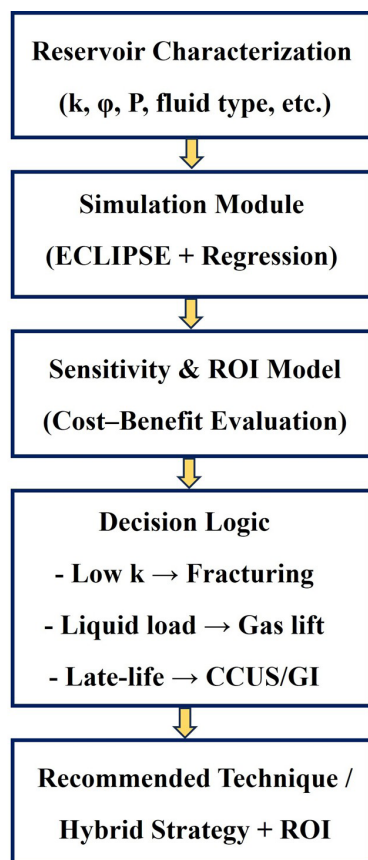


Figure 5. Conceptual decision-making framework

## 7. Future Research Directions and Current Challenges

### 7.1. Key Findings

Despite substantial progress in pressure enhancement technologies, several challenges persist that limit their technical and economic deployment:

1. Reservoir heterogeneity and uncertainty: Predicting fracture propagation and gas-liquid interaction in heterogeneous formations remains difficult, often resulting in variable recovery efficiency.
2. High operational and environmental costs: Techniques such as hydraulic fracturing and acidizing require substantial capital and may introduce environmental and water management concerns.
3. Integration complexity: Combining

stimulation, gas lift, and gas injection techniques requires multi-objective optimization and advanced control systems that are not yet fully standardized.

4. Data scarcity for AI models: Many AI-driven applications suffer from limited field-scale training datasets, constraining their accuracy and generalizability.
5. CCUS and nanotechnology scalability: While promising, CCUS and nano-assisted processes require further field validation under realistic reservoir conditions.

### 7.2. Future Research Directions

To overcome these challenges, several promising research avenues have emerged:

1. Hybrid and adaptive systems: Future work should focus on developing adaptive frameworks that integrate hydraulic fracturing, gas lift, and gas injection, optimized in real-time using machine learning algorithms.
2. AI-physics hybrid modeling: The combination of physics-based simulators (e.g., ECLIPSE) with AI predictive models could improve forecasting accuracy and enable automated control of pressure enhancement operations.
3. Advanced materials and nanofluids: Research on nano-engineered proppants and low-toxicity nanofluids could significantly enhance fracture conductivity, reduce damage, and improve environmental performance.
4. Techno-economic optimization: Coupled simulation-economic models should be developed to optimize pressure enhancement strategies under varying gas price scenarios and carbon regulations.
5. Digital twins and monitoring systems: Real-time digital twins integrating sensor data, simulation feedback, and predictive analytics can provide continuous decision

support for long-term field management.

Addressing these research directions will require interdisciplinary collaboration across reservoir engineering, data science, and environmental management, advancing both the technical and sustainable development of gas reservoir enhancement.

## 8. Conclusions

This study provides a comprehensive, simulation-based assessment of advanced pressure enhancement techniques in gas reservoirs, integrating technical, economic, and sustainability perspectives. The main findings and contributions can be summarized as follows:

**Simulation and Performance:** ECLIPSE-based simulations demonstrated that hydraulic fracturing achieved the highest production improvement (25-30%) in low-permeability formations, while gas lift yielded a 15-20% enhancement in liquid-loaded wells. The hybrid fracturing + gas-lift configuration offered the best overall efficiency and longevity.

**Economic Evaluation:** The cost–benefit analysis revealed a robust ROI of 2.3-2.5 for the hybrid scenario, with  $\pm 20\%$  cost sensitivity resulting in only minor ROI fluctuation ( $\pm 0.2-0.3$ ). This confirms the technique's stability and field feasibility under realistic market conditions.

**Statistical Insights:** Regression analysis ( $R^2 = 0.87$  for production;  $R^2 = 0.82$  for ROI) identified permeability and liquid accumulation as the dominant parameters influencing enhancement performance. Sensitivity indices verified their primary contribution to productivity outcomes.

**Innovation Integration:** AI-driven optimization, nanofluid-assisted stimulation, and CCUS-based gas injection represent emerging solutions for both technical improvement and environmental sustainability. Their quantified impact including 10-25% performance gains reported in literature reinforces their

integration into future reservoir management frameworks.

**Framework Contribution:** A novel decision-making framework (Figure 5) was developed, linking reservoir characteristics, simulation results, and economic criteria to recommend the most suitable enhancement technique or hybrid configuration. This provides a practical tool for field engineers to make data-driven, sustainable decisions.

Overall, the study advances a unified, quantitative perspective on gas reservoir enhancement, bridging simulation analytics with techno-economic and environmental considerations. The proposed framework can guide future research and field applications toward optimized, AI-assisted, and sustainability-oriented reservoir management.

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## مروری جامع و ارزیابی مبتنی بر شبیه‌سازی از روش‌های فشار افزایی در مخازن گازی

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### چکیده

حفظ فشار مخزن یکی از چالش‌های اصلی در میدان‌های گازی بالغ و کم‌تراوا است، جایی که بهره‌وری با کاهش فشار به سرعت افت می‌کند. این پژوهش یک ارزیابی جامع و چارچوب تصمیم‌گیری یکپارچه برای روش‌های پیشرفته افزایش فشار ارائه می‌دهد که ترکیبی از شبیه‌سازی‌های مخزنی مبتنی بر نرم‌افزار ECLIPSE، تحلیل‌های رگرسیونی و حساسیت و ارزیابی‌های اقتصادی است. در این تحقیق، روش‌هایی مانند شکاف‌زنی هیدرولیکی، اسیدکاری ماتریسی، گازلیفت، تزریق گاز و پیکربندی‌های ترکیبی مورد بررسی قرار گرفته‌اند. همچنین، نوآوری‌های نوظهوری مانند بهینه‌سازی مبتنی بر هوش مصنوعی (AI)، تحریک به کمک نانوفناوری و فناوری جذب، استفاده و ذخیره‌سازی کربن (CCUS) تحلیل شده‌اند.

نتایج نشان می‌دهد که شکاف‌زنی هیدرولیکی در مخازن با تراوایی پایین بیشترین افزایش تولید (حدود ۲۵ تا ۳۰ درصد) را ایجاد می‌کند، در حالی که گازلیفت در سیستم‌های دارای بار مایع بیشترین کارایی را داشته و منجر به افزایش ۱۵ تا ۲۰ درصدی تولید می‌شود. پیکربندی ترکیبی شکاف‌زنی-فرازآوری با گاز بهترین عملکرد اقتصادی را با نرخ بازده سرمایه (ROI) بین ۲/۳ تا ۲/۵ ارائه داده است که از طریق تحلیل حساسیت با تغییرات  $\pm 20\%$  در هزینه‌ها تأیید شده است. نتایج رگرسیونی با ضریب تعیین  $R^2 = 0.87$  نشان می‌دهد که تراوایی و تجمع مایع از مهم‌ترین متغیرهای مؤثر بر کارایی افزایش فشار هستند.

این مطالعه یک چارچوب تصمیم‌گیری نوین مبتنی بر شبیه‌سازی معرفی می‌کند که شاخص‌های فنی، اقتصادی و پایداری محیطی را در انتخاب بهترین راهکار افزایش فشار یکپارچه می‌سازد. این رویکرد یکپارچه، بررسی‌های توصیفی سنتی را به یک ابزار کمی و کاربردی در میدان تبدیل کرده و مسیر جدیدی را برای مدیریت کارآمدتر و پایدارتر مخازن گازی فراهم می‌آورد.

**واژگان کلیدی:** فشارافزایی مخازن گازی، بهبود بهره‌وری، مدیریت پایدار مخزن، بهینه‌سازی تولید گاز