PERFORMANCE EVALUATION OF GAS LIFT TECHNIQUES IN A NATURALLY FLOWING WELL USING PROSPER SIMULATOR: A CASE STUDY

BY

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A PROJECT SUBMITTED TO THE

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BENIN CITY.

CERTIFICATION

This is to certify that this project was carried out by IBUKUN ANNAH OGHENEOMONI of the Department of Petroleum Engineering with matriculation number ENG2006426 in partial fulfillment of the requirements for the Award of the Degree, Bachelor of Engineering (B.ENG)

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DEDICATION

This thesis is dedicated to God Almighty, who made it possible for me to complete the study successfully. This work is dedicated to my father, mother, siblings, alongside my professors and lecturers who have taught me that the best kind of knowledge to have is that which is learned for its own sake and this have been a major source of motivation in this academic journey.

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Finally, a pat on the back to myself, Ibukun Annah, for the discipline, hard work, and grace under pressure that brought this project to fruition. For managing multiple responsibilities, maintaining focus on the goal, and never losing sight of excellence even in difficult times. This accomplishment is proof that with God's guidance, determination, and support from loved ones, dreams become reality.

In conclusion, this project has been an invaluable chapter in my learning journey, and I am thankful to each and every person who has contributed to making it a success.

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ABSTRACT

As reservoir pressure declines during production, naturally flowing wells eventually require artificial lift intervention to sustain economically viable production rates. Gas lift, one of the most widely adopted artificial lift methods, operates in two primary modes: continuous and intermittent injection. Selecting the optimal mode is critical for maximizing production while minimizing operational costs, yet many operators rely on costly trial-and-error field implementations rather than systematic evaluation. This study addresses this challenge by conducting a comprehensive, simulation-based comparative analysis of intermittent and continuous gas lift performance for a naturally flowing well using PROSPER (Production and System Performance Analysis) software. The case study well is completed at a true vertical depth of 11,500ft with 2.441-inch tubing and has a productivity index of 2.01 STB/day/psi. Under natural flow conditions, the well produces 264.2 STB/day at a reservoir pressure of 4,500 psia representing only 6.2% of its absolute open flow potential of 4,733.8 STB/day. The model was validated through nodal analysis by matching inflow performance relationships with vertical lift performance curves. Both gas lift methods were systematically evaluated through rigorous simulation. Continuous gas lift optimization revealed a design injection rate of 4.53 MMscf/day producing 1,369.58 STB/day, though economic considerations favored an optimized rate of 1.0 MMscf/day yielding 1,100 STB/day, representing a 76% increase over natural flow. Intermittent gas lift design employed five gas lift valves with optimized spacing and achieved dramatically superior performance: 2,827.76 STB/day at a cycle frequency of 6.76 cycles/hour with only 0.026 MMscf/day gas injection, which is a 90.7% increase over natural flow and 61.1% improvement over continuous gas lift. The results demonstrate that intermittent gas lift provides superior production performance, exceptional gas utilization efficiency, and enhanced economic value for the studied well. This study validates that systematic, simulation-based evaluation using PROSPER enables confident, data-driven artificial lift selection, eliminating costly field trail-and-error methods.

CHAPTER ONE

INTRODUCTION

1.1 Background of Study

The petroleum industry's fundamental goal is to maximize the recovery of oil and gas from subterranean reservoirs. Initially, this process is straightforward, meaning that the natural pressure within the reservoir is typically high enough to force hydrocarbons to the surface, allowing the well to flow naturally. However, this natural flow is temporary. As production continues, reservoir pressure inevitably declines. This progressive pressure drop is the industry's central challenge, as it leads to reduced flow rates. Eventually, the reservoir pressure becomes too weak, and the well can no longer sustain economically viable production.

When the reservoir can no longer push the fluids, artificial lift methods become essential to keep the well productive. These systems must supply the extra energy needed to overcome the weight (hydrostatic pressure) of the fluid column and lift the oil to the surface. Among the numerous artificial lift technologies available, such as electrical submersible pumps (ESPs) and sucker rod pumps, gas lift has proven to be one of the most widely adopted methods. Its popularity stems from its reliability, operational flexibility, and relatively low maintenance needs, making it ideal for harsh environments like offshore or deviated wells and those producing corrosive fluids.

Gas lift works by injecting high-pressure gas into the production tubing. This process cleverly reduces the overall density of the fluid column. By making the oil column "lighter," the remaining reservoir pressure can more easily push the fluids to the surface, sustaining production. Gas lift systems operate primarily under two modes, chosen based on the well's specific characteristics: Continuous Gas Lift, which involves injecting gas at a steady, constant rate for wells with stronger productivity; and Intermittent Gas Lift, which involves injecting gas in periodic, high-pressure pulses, crucial for weaker wells where fluid must be allowed to accumulate (a "slug") before a strong gas pulse forces the batch to the surface.

The choice between continuous and intermittent gas lift is a critical design decision that directly impacts a well's profitability. An incorrect selection could lead to suboptimal production rates, excessive gas consumption, and increased operational costs. To mitigate this risk, modern petroleum engineering relies on well performance simulation tools like PROSPER (Production and System Performance Analysis). These tools allow engineers to use nodal analysis to model and predict well behavior under different operating conditions, enabling the optimization of injection parameters before costly field implementation. This study addresses this optimization imperative. By employing PROSPER simulation software to compare the production performance of both intermittent and continuous gas lift methods on a naturally flowing well, this research aims to provide data-driven insights into the most efficient gas lift strategy for maximizing oil recovery while minimizing the resource-intensive consumption of injection gas.

1.2 Statement of the Problem

The oil industry faces several critical challenges in maintaining optimal production from naturally flowing wells as they transition to requiring artificial lift:

1. Declining Reservoir Pressure and Production: Naturally flowing wells experience progressive pressure decline due to continuous fluid withdrawal, resulting in reduced flow rates, increased water cut, and eventual production cessation.
2. Gas Lift as Solution to Production Problems: Gas lift addresses fundamental production challenges, including insufficient reservoir pressure, high hydrostatic pressure in the

wellbore, high gas-oil ratios, sand production, and the need to extend well life and maximize ultimate recovery from depleting reservoirs.

3. Method Selection Challenge: Selecting between continuous and intermittent gas lift injection presents significant operational and economic challenges. Continuous gas lift may result in excessive gas consumption and operational inefficiencies when improperly applied, while intermittent gas lift requires precise cycle timing and can cause production instability if incorrectly implemented.
4. Lack of Systematic Evaluation: Most operators transition wells to gas lift without a comprehensive performance evaluation, relying on costly trial-and-error field implementations rather than predictive modeling. This results in suboptimal production rates, unnecessary operational expenditure, and the inability to maximize return on investment.
5. Absence of Simulation-Based Decision Support: The limited use of simulation tools like PROSPER for comparative analysis before field implementation leads to poor matching of gas lift methods to well conditions, a lack of injection rate optimization, and higher technical and financial risks.

This study addresses these problems by utilizing PROSPER simulation software to systematically compare intermittent and continuous gas lift methods, providing data-driven insights for optimal system selection and maximized oil recovery

1.3 Aim of the Study

This study aims to evaluate and compare the performance of intermittent and continuous gas lift injection methods for a naturally flowing well using PROSPER simulation software.

1.4 Specific Objectives

The goals of this project are to:

1. Develop a well performance model for the naturally flowing well using PROSPER software
2. Determine the oil production rate achievable with intermittent gas lift injection
3. Determine the oil production rate achievable with continuous gas lift injection
4. Determine the optimum gas injection rate for both intermittent and continuous gas lift methods
5. Compare the performance and efficiency of intermittent and continuous gas lift systems
6. Recommend the most suitable gas lift injection method for the well under study

1.5 Scope of the Study

This research is designed to be a highly focused and in-depth evaluation. Our findings will be confined to a single, specific, naturally flowing oil well, limiting the scope to a performance comparison between only two methods: intermittent gas lift and continuous gas lift.

The work will proceed strictly within the following boundaries:

- Software Focus: All modeling, simulation, and performance predictions will be conducted exclusively within the PROSPER software environment.
- Methodology: We will analyze only the two gas lift injection modes. No other artificial lift methods (like ESPs or sucker rod pumps) are included in this comparison.
- Case Study Basis: The entire analysis is founded on the specific reservoir, fluid, and completion characteristics provided for the single case study well.
- Key Metrics: The performance evaluation is focused solely on two primary indicators: oil production rates and the corresponding optimum gas injection rates for both lift methods.
- Analysis Type: This is a simulation-based study. The findings are derived entirely from computer modeling using PROSPER and do not involve actual field implementation or testing.
- Data Reliance: The accuracy of the model is dependent on the provided production data, completion data, and well schematic information used to build the digital well model.

1.6 Limitations

The following limitations are recognized in this study:

- Reliance on the Digital Model: Analysis is based entirely on PROSPER software simulation and lacks field validation. While the model is robust, actual field performance may vary due to operational conditions or reservoir complexities that a software model simply cannot capture perfectly.
- The Quality of Inputs: The precision of results is entirely dependent on the data provided. Any inaccuracies or gaps in the input data, including production history, PVT properties, or reservoir details, will directly affect the reliability of the simulation outcomes.

- One-Well Focus: This research is a single well case study. Consequently, the specific findings and final recommendations are tailored to this well alone and should not be directly applied to other wells, which may have different reservoir conditions, fluid types, or completion designs.
- Scope of Metrics: Evaluation is primarily focused on technical performance (oil production and gas injection rates). We have excluded detailed economic analysis, such as full cost-benefit evaluations, profitability metrics, or other detailed operational parameters from our scope.
- Software Constraints: The study is inherently limited by the capabilities of PROSPER software itself, including the accuracy of its internal correlations and the underlying assumptions built into its calculation models.

1.7 Justification and Significance of the Study

This study is critical because it moves beyond guesswork and directly addresses key challenges faced by the petroleum industry. The research is justified and significant for the following reasons:

1. Eliminating Costly Guesswork: Providing a systematic, simulation-based roadmap for gas lift selection dramatically reduces the financial risk and operational costs associated with inefficient trial-and-error implementations in the field.
2. Maximizing Recovery and Performance: By determining the most effective gas lift method and the optimum injection rates, the study directly translates into enhanced oil recovery and improved overall well production performance.

3. Boosting Economic Efficiency: The findings help production teams identify the optimal gas lift strategy before deployment, which is crucial for minimizing gas consumption and operational expenditure.
4. Empowering Better Decisions: This research offers production engineers and operators clear, data-driven insights. It provides the necessary technical evidence to make informed, defensible decisions about artificial lift selection tailored to specific well conditions.
5. Advancing Technical Skills: The study showcases the practical application of the industry-standard simulation tool, PROSPER, in solving a critical real-world petroleum engineering challenge, thereby contributing to the development of professional competency.
6. Contributing to Industry Knowledge: This research adds valuable knowledge to the comparative analysis of gas lift performance and establishes a replicable methodology that can be adapted for similar optimization studies across different fields.

The outcomes of this work have direct relevance to both industry practice and academic research in petroleum production engineering.

CHAPTER TWO

LITERATURE REVIEW

2.1 Natural Flow Production

During the early life of an oil well, reservoir pressure is typically sufficient to drive hydrocarbons to the surface through natural flow. In this phase, the reservoir's natural energy (primarily from rock and fluid expansion, solution gas drive, water influx, or gas cap expansion) provides the necessary force to overcome the hydrostatic pressure of the fluid column and lift fluids to the surface without external assistance (Economides et al, 2012).

Natural flow occurs when the reservoir pressure at the sand face exceeds the sum of the hydrostatic pressure of the fluid column in the wellbore, friction losses in the tubing, and surface equipment pressure. The driving mechanism originates from the pressure differential between the high-pressure reservoir and the low-pressure surface facilities. This pressure differential creates the energy required to move reservoir fluids from the formation through the wellbore and to the surface equipment.

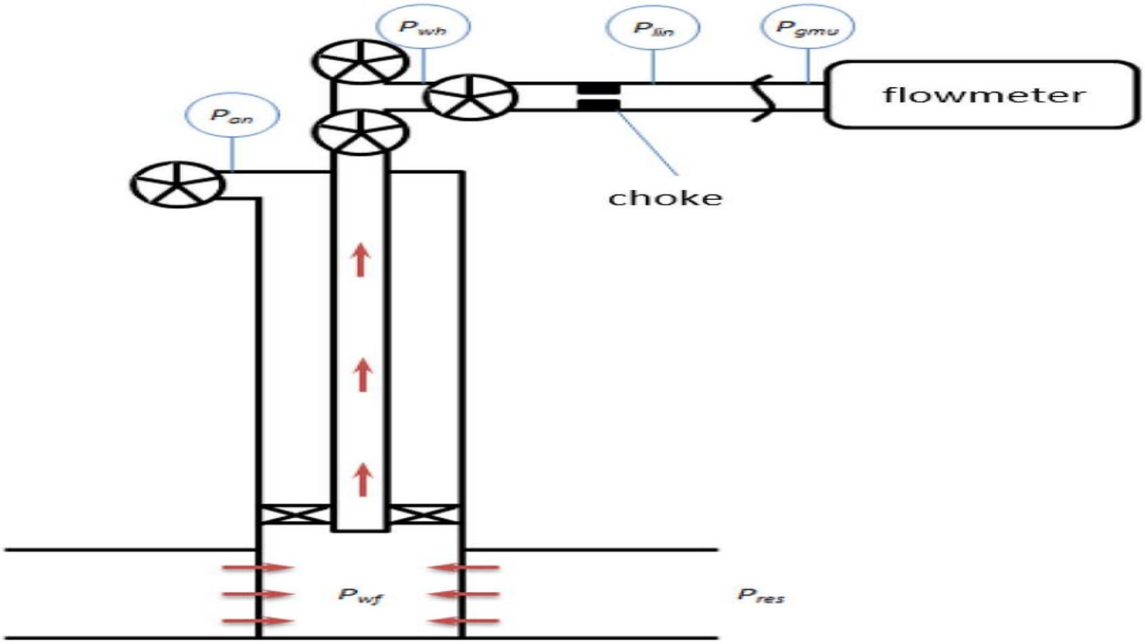


Figure 2. 1: Schematic of a naturally flowing well showing pressure measurement points and flow direction from the reservoir through tubing to surface facilities.

Where:

P_{wh} = wellhead pressure

P_{res} = reservoir pressure

P_{wf} = wellhead flowing pressure

P_{an} = annulus pressure

P_{lin} = line pressure

P_{smu} = surface measurement unit pressure

As shown in Figure 2.1, a naturally flowing well consists of a dual-string completion with production flowing through the tubing (indicated by red arrows) from the reservoir to the surface. The pressure at the wellhead (P_{wh}), line pressure (P_{lin}), and downstream measurement points must all be lower than the reservoir pressure (P_{res}) for natural flow to occur. The annulus (P_{an}) typically contains gas or fluid that provides additional monitoring capability but does not contribute to lifting in natural flow conditions.

The fundamental equation governing natural flow can be expressed as:

$P_{reservoir} + P_{hydrostatic} + P_{friction} + P_{surface}$

Where:

$P_{reservoir}$ = Reservoir pressure at the sandface

$P_{hydrostatic}$ = Hydrostatic pressure of fluid column

$P_{friction}$ = Pressure losses due to friction in tubing

$P_{surface}$ = Surface equipment back pressure

The natural flow phase represents the most economical production period for any oil well, as it requires minimal operating costs and no additional energy input beyond the reservoir's natural energy. Wells producing under natural flow conditions typically exhibit high production rates initially, which generally decline as reservoir energy depletes over time. The rate of decline depends on several factors, including reservoir drive mechanism, reservoir size, fluid properties, permeability, and production rates (Guo et al, 2007).

Natural flow is sustained as long as the pressure at the perforations remains sufficient to overcome all downstream resistances. The productivity of a naturally flowing well is concerned with the inflow performance relationship between the bottom-hole flowing pressure and production rate for a given reservoir pressure.

2.2 Reservoir Pressure Decline and Production Challenges

As production continues, reservoir pressure declines progressively due to continuous fluid withdrawal from the reservoir. This pressure depletion is a natural and inevitable consequence of hydrocarbon production and follows predictable patterns depending on the reservoir drive mechanism, fluid properties, production rates, and reservoir geometry (Ahmed, 2010).

The decline in reservoir pressure manifests in several critical production challenges that eventually necessitate artificial lift intervention.

2.2.1 Reduced production rates

As reservoir pressure decreases, the pressure differential between the reservoir and the wellbore diminishes, resulting in lower flow rates. The relationship between reservoir pressure decline and production rate is not linear; rather, it follows decline curve patterns that can be exponential, hyperbolic, or harmonic depending on the reservoir characteristics. The well's ability to deliver fluids to the surface becomes progressively limited as the driving force weakens.

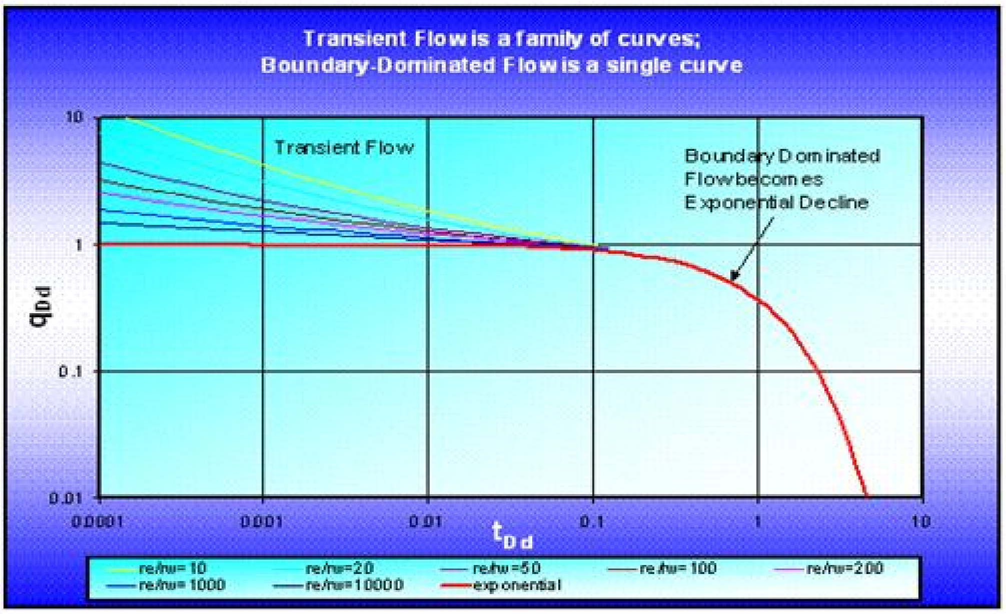


Figure 2. 2: Fetkovich decline curve shows the transition from transient flow (family of curves) to boundary-dominated flow (single exponential decline curve).

Figure 2.2 illustrates the characteristic decline behavior described by Fetkovich (1980), who demonstrated that well production typically progresses through two distinct phases. The initial phase known as transient flow, is characterized by a family of curves where the decline rate depends on the reservoir-to-wellbore radius ratio (r_e/r_w) and represents the period when the pressure transient is still propagating through the reservoir. During this phase, production rates decline gradually as the well drains an expanding volume of the reservoir.

The second phase, boundary-dominated flow, begins when the pressure transient reaches the reservoir boundaries. At this point, the entire reservoir is in communication with the wellbore, and production follows a single exponential decline curve regardless of the reservoir size. This transition is critical because it marks the point where reservoir pressure begins declining more rapidly, and the well's production becomes increasingly sensitive to pressure depletion.

Fetkovich demonstrated that the decline in production rate accelerates when bottom-hole flowing pressure drops below the bubble point pressure, causing free gas to form in the reservoir. This gas formation reduces the relative permeability to oil and further impairs the well's productivity. The resulting production decline can be described by various mathematical models, with the most common being exponential decline:

$$\mathbf{q\ (t) = q_i \times e^{(-Di \times t)}}$$

q (t) = Production rate at time t

q_i = Initial production rate

Di = Decline rate constant

t = Time

The dimensionless variables shown in Figure 2.2 allow engineers to predict decline behavior for wells with different reservoir properties and drainage areas. Wells with larger drainage areas (higher r_e/r_w ratios) maintain transient flow longer before entering boundary-dominated decline, while wells with smaller drainage areas transition to exponential decline more quickly.

2.2.2 Increased water cut

Many reservoirs experience water coning or water encroachment as pressure declines, leading to increased water production alongside oil. Water coning occurs when the pressure drawdown near the wellbore is sufficient to overcome gravity forces, causing water from the aquifer or water zone to cone upward into the perforations.

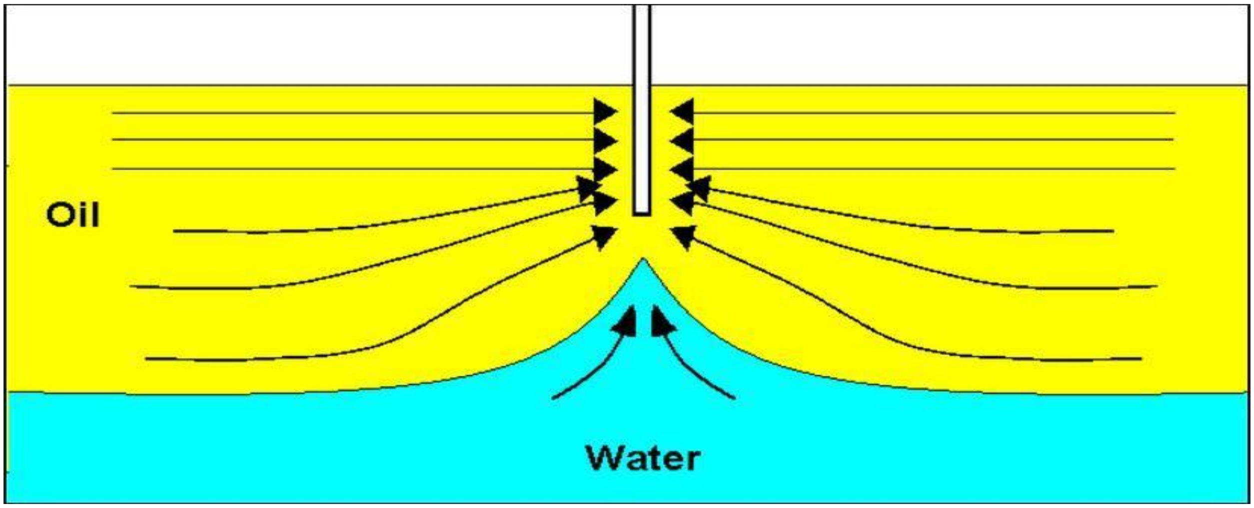


Figure 2. 3: Water coning mechanism showing the upward movement of water from the underlying aquifer toward the wellbore perforations (Okon et al, 2017)

As illustrated in Figure 2.3, water coning is a gravity-drainage phenomenon where the upward viscous forces created by production pressure drawdown overcome the downward gravitational forces that normally keep water and oil separated. The water forms a characteristic cone shape as it rises toward the perforations. Once the cone reaches the perforations, water breakthrough occurs, and the well begins producing increasing amounts of water along with oil (Terotos, I.E, 2015 P. 30).

The critical rate for water coning can be estimated using various correlations, with the most widely used being Meyer and Garder's equation or Chaperon's correlation. These relationships show that the critical rate is inversely proportional to the pressure drawdown; higher production rates create stronger drawdown and increase the likelihood of water coning. Wells with long perforation intervals, high permeability, and significant oil column thickness above the oil-water contact are less susceptible to early water breakthrough.

Increased water production has multiple detrimental effects on well performance. First, water has a higher density than oil (typically 1.0-1.1 g/cm³ compared to 0.8-0.9 g/cm³ for oil), which increases the hydrostatic pressure of the fluid column in the wellbore. This heavier column requires more reservoir pressure to lift to the surface, creating a feedback loop where declining reservoir pressure struggles to lift increasingly heavy fluid columns.

- The hydrostatic pressure difference can be significant. For example, in a 5,000-foot well:
- Pure oil column (0.85 sg): ~1,850 psi
- 50% water cut (0.93 sg average): ~2,025 psi
- 80% water cut (1.02 sg average): ~2,220 psi

This additional 370 psi of hydrostatic pressure from high water cut requires proportionally more reservoir pressure to maintain the same production rate, accelerating the need for artificial lift intervention.

Second, water production reduces the economic value of produced fluids, as water must be separated, treated, and disposed of at significant cost. Water handling costs can range from $0.50 to $5.00 per barrel, depending on the treatment requirements and disposal method. High water cut also affects the efficiency of surface facilities and can cause corrosion and scaling problems in production equipment (Kelland, 2009).

Third, water production can lead to formation damage through clay swelling, fines migration, or scale deposition near the wellbore, further reducing well productivity. Some formations are particularly sensitive to water contact, and even modest water production can cause irreversible permeability damage.

2.2.3 Gas breakthrough and production instability

In wells producing from reservoirs with gas caps or high solution gas content, declining reservoir pressure can lead to gas breakthrough. This occurs when preferential flow paths develop that allow gas to reach the wellbore ahead of oil, or when the pressure drops below the bubble point, causing solution gas to come out of the oil throughout the reservoir (Standing, 1952).

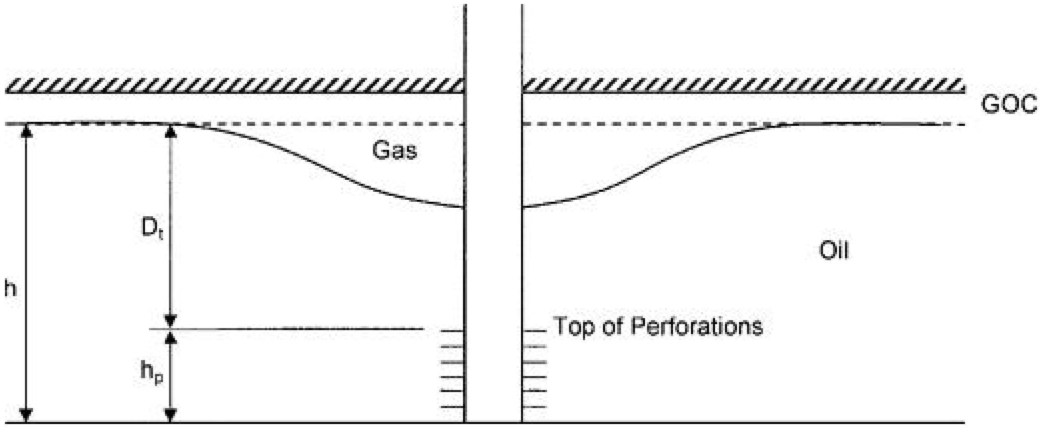


Figure 2. 4: Gas coning mechanism showing downward movement of gas from the overlying gas cap toward the wellbore perforations.

As illustrated in Figure 2.4, gas coning is the inverse of water coning, where gas from an overlying gas cap moves downward toward the producing perforations due to pressure drawdown created by production. The gas-oil contact (GOC), which is initially flat and horizontal due to gravity segregation, becomes distorted into a cone shape pointing downward toward the wellbore.

The critical parameters for gas coning include:

- h : Total oil column thickness from gas-oil contact to water-oil contact
- D_i : Initial distance from perforations to the gas-oil contact

- h_c : Height of the gas cone above the original gas-oil contact
- Top of Perforations: The completion interval where oil is produced

Similar to water coning, there exists a critical production rate below which the gas cone remains stable and does not reach the perforations. If production exceeds this critical rate, the upward viscous forces overcome the downward gravitational forces that tend to keep gas and oil separated, and the cone progresses toward the perforations. When a gas breakthrough occurs, the produced Gas-Oil Ratio (GOR) increases dramatically.

Wells completed too close to the gas cap or produced at excessive rates are particularly susceptible to early gas breakthrough. Once a breakthrough occurs, controlling or reversing the coning is extremely difficult, and the well may experience permanently elevated GOR even if production rates are subsequently reduced.

Gas breakthrough creates several operational challenges. The presence of free gas in the wellbore creates multiphase flow conditions characterized by different flow regimes, bubble flow, slug flow, churn flow, and annular flow, each with distinct pressure gradient characteristics. These flow regimes can transition unpredictably, causing production instability and making it difficult to maintain steady flow rates.

Additionally, high gas velocities can cause liquid carryover problems where oil droplets are entrained in the gas stream and lost to the gas gathering system rather than being properly separated and collected as oil production. This phenomenon reduces oil recovery efficiency and can create operational problems in gas handling facilities.

2.2.4 Liquid loading

As the well's energy decreases, liquids may accumulate in the wellbore, creating a heavier fluid column that further restricts production. This phenomenon, known as liquid loading, occurs when the gas velocity in the tubing is insufficient to lift liquid droplets to the surface (Terotos, I.E, 2015 P. 30).

The critical gas velocity required to prevent liquid loading can be estimated using correlations developed by Turner, Coleman, and others. Turner's criterion suggests a minimum gas velocity of approximately 10-20 ft/s is required to continuously remove liquids from gas wells, though the exact value depends on tubing size, pressure, temperature, and fluid properties.

Liquid loading manifests through several observable symptoms:

- Declining production rates despite stable reservoir pressure
- Increasing the flowing tubing pressure
- Erratic or intermittent flow
- Presence of liquids in gas sales lines
- Well heading (cyclic pressure and rate variations)

If liquid loading is not addressed, the accumulated liquid column can eventually become heavy enough to kill the well completely, stopping production despite significant remaining reserves in the reservoir

2.2.5 Wellbore dynamics and flow assurance

Declining reservoir pressure also affects various flow assurance issues. Lower pressures and temperatures can promote hydrate formation in gas-producing zones, paraffin deposition in oil wells, and asphaltene precipitation, all of which can restrict flow and reduce production (Musnal & Fitrianti, 2017).

The reduction in pressure also affects the efficiency of surface facilities. Separators, which rely on pressure reduction to separate gas from liquid, may not function optimally at low pressures. Pumps, compressors, and other equipment may operate outside their design envelopes, leading to inefficiencies and increased maintenance requirements.

2.2.6 Economic Considerations

Eventually, the natural flow rate declines to a point where production becomes economically unviable. This economic limit is reached when the revenue from production no longer exceeds the operating costs of maintaining the well. The well may still contain significant remaining reserves, often 70-80% of the original oil in place, but the reservoir energy is insufficient to produce them economically without intervention.

The economic limit is not a fixed value. Still, it depends on multiple factors, including oil prices, operating costs, production rates, water cut, regulatory requirements, and the availability and cost of artificial lift alternatives. In many cases, implementing artificial lift at the right time can extend the economic life of a well by decades and significantly increase ultimate recovery.

2.3 Need for Artificial Lift

When reservoir pressure becomes insufficient to lift fluids to the surface at economical rates, artificial lift methods become necessary to sustain or enhance production. Artificial lift systems provide the additional energy required to overcome the hydrostatic pressure of the fluid column in the wellbore and the pressure losses in the production system (Takacs, 2005).

The implementation of artificial lift serves several critical purposes that directly address the production challenges associated with declining reservoir pressure:

2.3.1 Production sustainability and reserve recovery

Artificial lift enables continued production from wells that would otherwise cease flowing, prevent premature abandonment of reserves, and maximize ultimate recovery from the reservoir. Studies have shown that wells equipped with appropriate artificial lift systems can produce economically for 20-30 years longer than the natural flow period, recovering an additional 15-30% of original oil in place that would otherwise remain stranded in the reservoir.

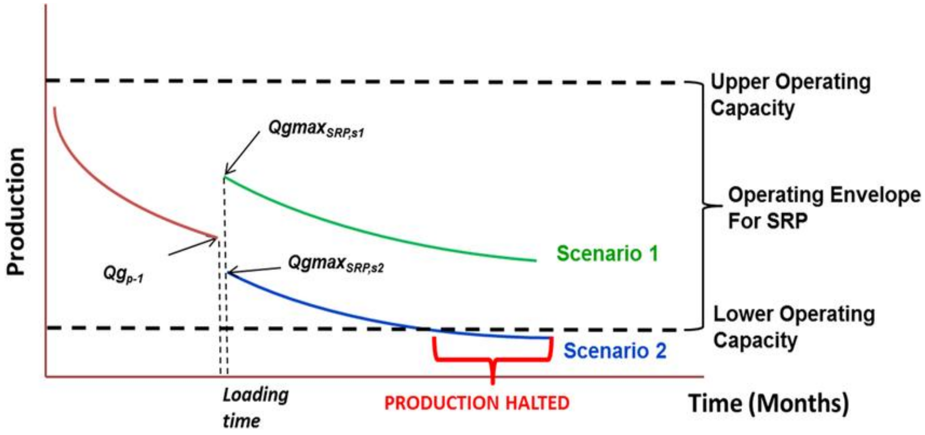
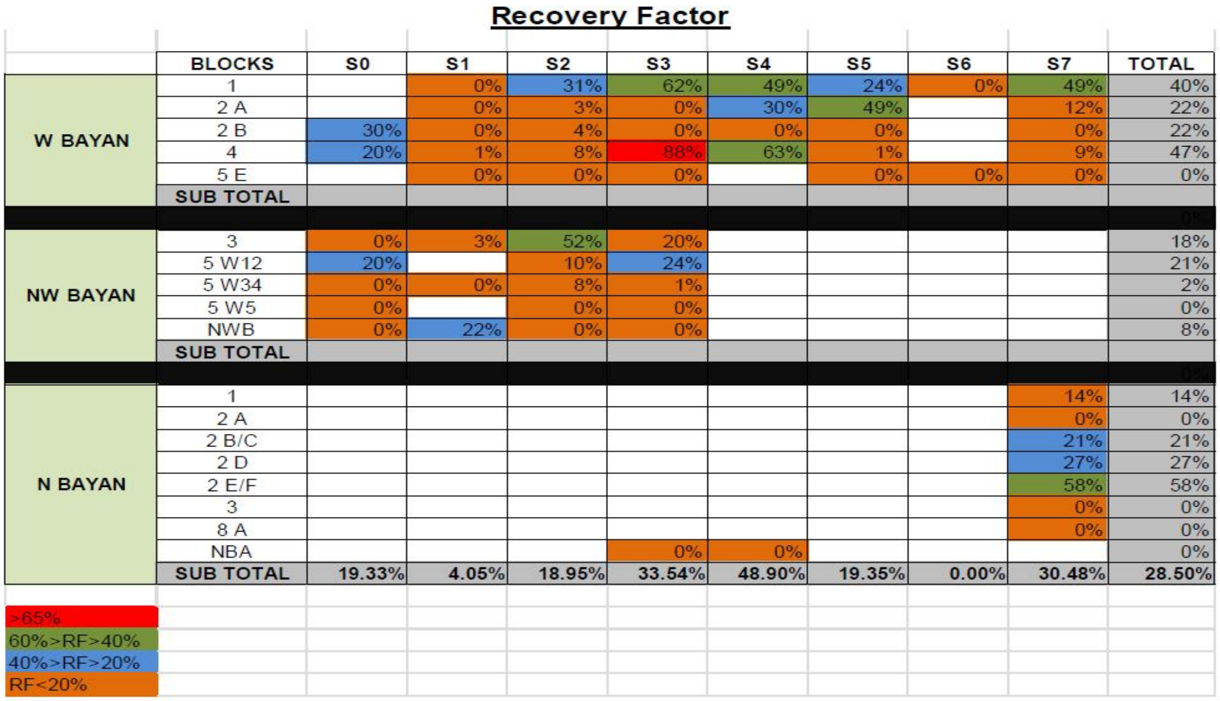


Figure 2. 5: Production decline curve showing the typical life cycle of an oil well

Figure 2.5 demonstrates the critical timing decision for artificial lift implementation. The curve shows that wells experiencing natural decline eventually reach an economic limit where operating costs exceed revenue. However, by implementing artificial lift at the optimal point, typically when production has declined to 50-70% of peak rates, operators can restore production to economically viable levels and extend well life by decades. The incremental recovery represented by the shaded area can account for 15-30% of total reserves, making artificial lift implementation one of the most value-adding decisions in field development.

Real-world examples demonstrate the dramatic impact of artificial lift on production recovery. In the Buzurgan oil field in southern Iraq, well MB21 experienced production decline to zero barrels per day due to declining reservoir pressure from 4400 psia to 3000 psia and increasing water cut up to 25%. Through the implementation of gas lift artificial lift with an optimized injection rate of 8 MMscf/day, the well was successfully revived, increasing production from 0 STB/day to 396.6 STB/day (Hatif et al., 2025).

Similarly, in the Bayan oil field offshore Sarawak, Malaysia, gas lift optimization was implemented across multiple reservoir blocks experiencing production decline. The optimization strategy resulted in expected additional recovery ranging from 1% to 16% of original oil in place across different field segments, with some high-performing blocks achieving recovery factors exceeding 10% through gas lift implementation (Roslan, 2012).



Recovery Factor

	BLOCKS	S0	S1	S2	S3	S4	S5	S6	S7	TOTAL
W BAYAN	1		0%	31%	62%	49%	24%	0%	49%	40%
	2 A		0%	3%	0%	30%	49%		12%	22%
	2 B	30%	0%	4%	0%	0%	0%		0%	22%
	4	20%	1%	8%	88%	63%	1%		9%	47%
	5 E		0%	0%	0%		0%	0%	0%	0%
	SUB TOTAL									
										0%
NW BAYAN	3	0%	3%	52%	20%					18%
	5 W12	20%		10%	24%					21%
	5 W34	0%	0%	8%	1%					2%
	5 W5	0%		0%	0%					0%
	NWB	0%	22%	0%	0%					8%
	SUB TOTAL									
										0%
N BAYAN	1								14%	14%
	2 A								0%	0%
	2 B/C								21%	21%
	2 D								27%	27%
	2 E/F								58%	58%
	3								0%	0%
	8 A								0%	0%
	NBA				0%	0%				0%
	SUB TOTAL	19.33%	4.05%	18.95%	33.54%	48.90%	19.35%	0.00%	30.48%	28.50%

🟥 >65%
🟩 60%>RF>40%
🟦 40%>RF>20%
🟧 RF<20%

Figure 2. 6: Recovery factor distribution across Bayan field reservoir blocks showing current recovery performance by sector (West Bayan, Northwest Bayan, North Bayan) and sand layers (S0-S7).

Figure 2.6 provides critical insights for prioritizing gas lift optimization efforts across the Bayan field. The color-coded recovery factor map reveals several important patterns

- West Bayan Sector demonstrates the most mature production with several blocks showing recovery factors above 40%. Block 4, Sand S3 shows exceptional performance at 88% recovery (red), indicating near-complete depletion where incremental gas lift potential may be limited. However, Block 1 shows more moderate recovery factors of 31-62% across sands S2-S4 (green/blue), representing excellent candidates for gas lift enhancement with substantial remaining reserves and adequate reservoir pressure to respond to artificial lift.

- Northwest Bayan Sector displays generally lower recovery factors (18-24%), predominantly in the orange and blue categories, suggesting these blocks are either in early production life or have productivity challenges. Block 3 with 52% recovery in S2 (green) and Block 5 W12 with 10-24% recovery represent different optimization opportunities. Higher recovery blocks may benefit from gas lift to maintain plateau production, while lower recovery blocks may require investigation of the root causes limiting recovery before committing to gas lift investment.
- North Bayan Sector shows the most variable performance. Block 2E/F achieves 58% recovery (green), demonstrating good productivity that could be enhanced through gas lift. Blocks 2B/C and 2D show moderate recovery (21-27%, blue), indicating potential gas lift candidates. However, several blocks show 0% recovery (NBA, Block 2A, Block 3, Block 8A), which may indicate wells not yet brought online, shut-in wells, or blocks with fundamental completion or reservoir quality issues requiring resolution before artificial lift consideration.
- The sector subtotals reveal field-wide patterns: West Bayan averages the highest recovery, Northwest Bayan shows moderate but consistent performance, and North Bayan displays the most variability. The overall field recovery factor of 28.50% indicates the field is in mid-life, with substantial reserves remaining (over 70% of STOIIP) that could potentially be accessed through optimized gas lift implementation.

The distribution of recovery factors suggests a phased gas lift optimization strategy:

- Priority 1 (Green blocks, 40-60% RF): Implement gas lift on moderately depleted blocks with proven productivity to maximize incremental recovery

- Priority 2 (Blue blocks, 20-40% RF): Evaluate gas lift for less depleted blocks where natural decline is beginning
- Priority 3 (Orange blocks, <20% RF): Investigate root causes of poor recovery before artificial lift investment
- Lower Priority (Red blocks, >65% RF): Consider for gas lift only if economic analysis shows positive returns despite limited remaining reserves

This systematic, color-coded approach enables field operators to allocate limited capital and injection gas resources to wells and blocks with the highest probability of economic success, maximizing field-wide oil recovery while minimizing investment risk (Roslan, 2012).

These field examples underscore the critical role of artificial lift in maximizing reserve recovery from mature fields. The importance of artificial lift in reserve recovery cannot be overstated. In many mature oil fields worldwide, the majority of production comes from wells on artificial lift rather than natural flow. For example, in the United States, over 90% of producing oil wells utilize some form of artificial lift, with similar percentages in other mature producing regions. Without artificial lift technology, global oil production would be a fraction of current levels, and vast hydrocarbon resources would remain unrecoverable.

The timing of artificial lift implementation is critical for maximizing reserve recovery. Installing artificial lift too early increases capital and operating costs unnecessarily, while waiting too long can result in several negative consequences:

- Production losses: Extended periods of marginal natural flow represent lost revenue and delayed cash flow

- Wellbore damage: Prolonged liquid loading can cause formation damage through water blocking or scale deposition
- Restart difficulties: Wells that completely die from liquid loading may be difficult or impossible to restart without expensive intervention
- Lost reservoir energy: In wells with active water or gas drive, delayed artificial lift implementation can result in premature water or gas breakthrough
- Increased water cut: Wells allowed to produce at very low rates may experience accelerated water coning

2.3.2 Production rate optimization

Even in wells still capable of natural flow, artificial lift can significantly increase production rates by reducing the flowing bottom-hole pressure, thereby increasing the pressure drawdown on the reservoir. The relationship between drawdown and production rate is described by the productivity index (PI):

$q = PI \times (P_r - P_{wf})$

Where:

q = Production rate (STB/D)

PI = Productivity index (STB/D/psia)

P_r = Average reservoir pressure (psia)

P_{wf} = Flowing bottom-hole pressure (psia)

By reducing P_{wf} through artificial lift, the drawdown (P_r - P_{wf}) increases substantially, leading to higher production rates even from partially depleted reservoirs. This optimization can increase production by 50-200% compared to late-stage natural flow rates (Brown, 1984).

2.4 Artificial Lift Methods

2.4.1 Overview of artificial lift technologies

Artificial lift refers to any method used to increase the flow of liquids from a producing well when natural reservoir pressure is insufficient to produce fluids at economical rates. The petroleum industry has developed several artificial lift technologies over the decades, each with specific applications, advantages, and limitations. The primary artificial lift methods include:

- **Sucker Rod Pumping (Beam Pumps):** This is the most widely used artificial lift method globally, particularly for low to medium production rate wells. The system uses a surface prime mover (usually an electric motor or gas engine) connected to a beam pumping unit that drives a string of sucker rods. The rods transmit reciprocating motion to a downhole pump that lifts fluids to the surface through positive displacement action.

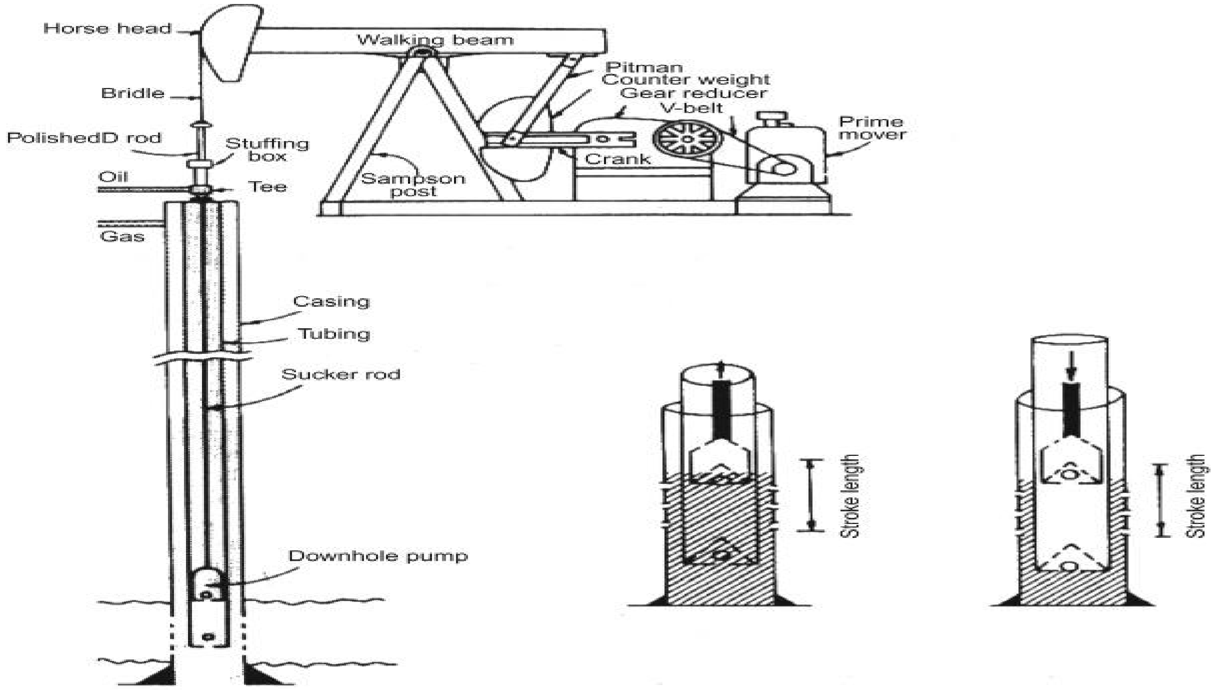


Figure 2. 7: A diagrammatic drawing of a sucker rod pumping system (Golan and Whitson, 1991).

- **Electric Submersible Pumps (ESP):** ESP systems consist of a downhole centrifugal pump driven by an electric motor; both are submerged in the well fluids. The pump consists of multiple stages (typically 50-400 stages) of impellers and diffusers that progressively increase pressure as fluid moves from intake to discharge. ESPs are ideal for high production rate wells and can handle large fluid volumes efficiently, making them the preferred choice for high-capacity producers (Takacs, 2005).

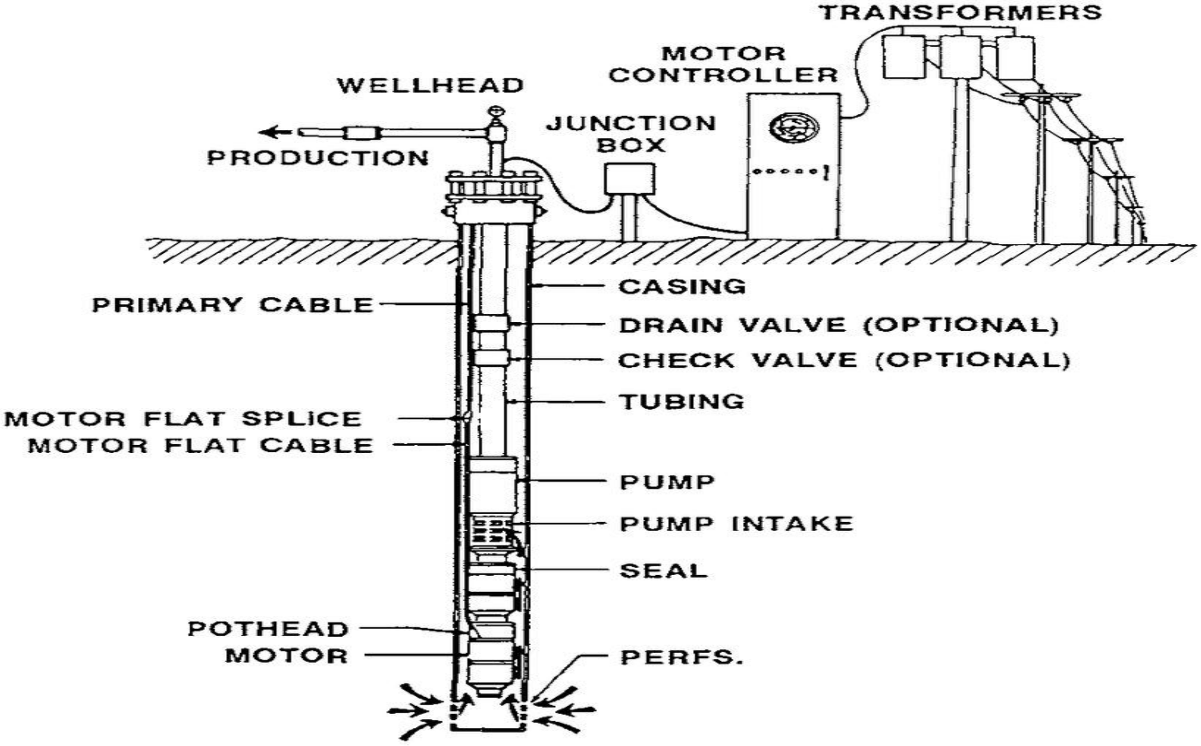


Figure 2. 8: Basic elements of the Electric Submersible Pump (Clegg, J, 1993)

- **Progressive Cavity Pumps (PCP):** PCPs use a helical rotor inside a double-helix stator to create cavities that progress from the pump intake to discharge as the rotor turns. The rotor is typically made of hardened steel, while the stator uses an elastomer material that creates a seal with the rotor. This positive displacement design handles viscous fluids exceptionally well, making PCPs the preferred choice for heavy oil production (Roslan, 2012).
- **Hydraulic Pumping:** This method uses hydraulic power fluid (usually oil) pumped from the surface to operate a downhole reciprocating or jet pump. The power fluid is pressurized at the surface using a triplex pump and transmitted through small-diameter

tubing to the downhole pump. After performing work in the pump, the power fluid returns to surface mixed with produced fluids (Brown, 1984).

- **Plunger Lift:** Plunger lift is primarily used in gas wells with liquid loading problems rather than oil wells requiring full artificial lift. A free-traveling plunger (typically a 3-6 feet long steel cylinder) moves up and down the tubing, creating an interface between gas and liquid. Gas pressure builds below the plunger when it is at the bottom, then lifts the plunger and liquid column above it to the surface in a rapid cycle (Lea et al., 2008). This method requires minimal equipment (plunger, surface controller, motor valve) and is cost-effective for intermittent liquid removal from gas wells.
- **Gas Lift:** Gas lift involves injecting high-pressure gas into the production tubing to reduce the density of the fluid column, thereby reducing the flowing bottom-hole pressure and allowing the reservoir to produce at higher rates. Gas lift is one of the most flexible and reliable artificial lift methods, particularly suitable for high GOR wells, deviated wells, and wells with sand or corrosive fluid production (Elldakli, 2017).

Gas lift operates by injecting gas through gas lift valves installed in mandrels on the tubing string. The injected gas mixes with produced fluids, reducing the average mixture density and therefore the hydrostatic pressure gradient. This reduced gradient lowers the flowing bottom-hole pressure, increasing drawdown and enabling higher production rates. The system can operate continuously with steady gas injection or intermittently with cyclic injection and slug production (Hatif et al., 2025).

2.5 Comparative Table of Artificial Lift Methods

Table 2. 1: Comparison of major artificial lift methods, showing typical depth range, production rate range, best applications, primary limitations, relative capital cost, relative operating cost, and suitability for various well conditions.

Lift Method	Depth Range	Rate Range (BPD)	Best Applications	Key Limitations	Capital Cost	Operating Cost	Gas Tolerance	Sand Tolerance
Sucker Rod Pump	Up to 14000ft	5-5,000	Low-medium rates, vertical wells, stable production	Poor for deviated wells, high gas, requires surface space	Medium	Low-Medium	Poor	Fair
ESPs	Up to 15000ft	150-100,000	High rates, high volumes, offshore	Sensitive to gas/solids, high power requirement	High	High	Poor	Poor
PCP	Up to 6000ft	50-5,000	Heavy oil, high solids, viscous fluids	Limited depth, temperature-sensitive elastomer	Medium	Medium	Fair	Good

Hydraulic pump	Up to 15000ft	50-20,000	Remote locations, multiple wells, deviated wells	Complex surface facilities, moderate efficiency	High	High	Good	Fair
Plunger lift	Up to 18000ft	10-500	Gas wells with liquid loading, low liquid rates	Requires gas energy, intermittent production	Low	Low	Excellent	Fair
Gas Lift	Up to 20000ft	50-50,000	High GOR, deviated wells, offshore sand production	Requires a gas source and compression	Medium-High	Medium	Excellent	Excellent

2.6 Gas Lift Technology

Among artificial lift methods, gas lift is particularly attractive for subsea and high-temperature/high-sand wells because of its mechanical simplicity, ease of intervention, and tolerance for solids. Gas lift is an artificial lift method used in oil and gas production to enhance the flow of well fluids when the natural reservoir pressure is no longer sufficient to lift the fluids to the surface at an economically viable rate [Okon et al., 2023]. The primary consideration in the selection of a gas-lift system to lift a well, a group of wells, or an entire field is the availability and compression cost of gas (Rolan, 2012). The core mechanism is based on fundamental fluid dynamics principles: reducing the density of the fluid column in the production tubing [Amanze & Amadichuku, 2024].

The fundamental principle can be understood through the pressure gradient equation for multiphase flow in vertical pipes:

$dp/dh = \rho_m \times g + \text{friction losses}$

Where:

dp/dh = pressure gradient

ρ_m = mixture density

g = gravitational acceleration

By injecting gas into the production stream, the mixture density (ρ_m) decreases significantly, which reduces the pressure gradient. This reduction in pressure gradient lowers the flowing bottom-hole pressure (FBHP), increasing the pressure drawdown on the reservoir and allowing higher production rates.

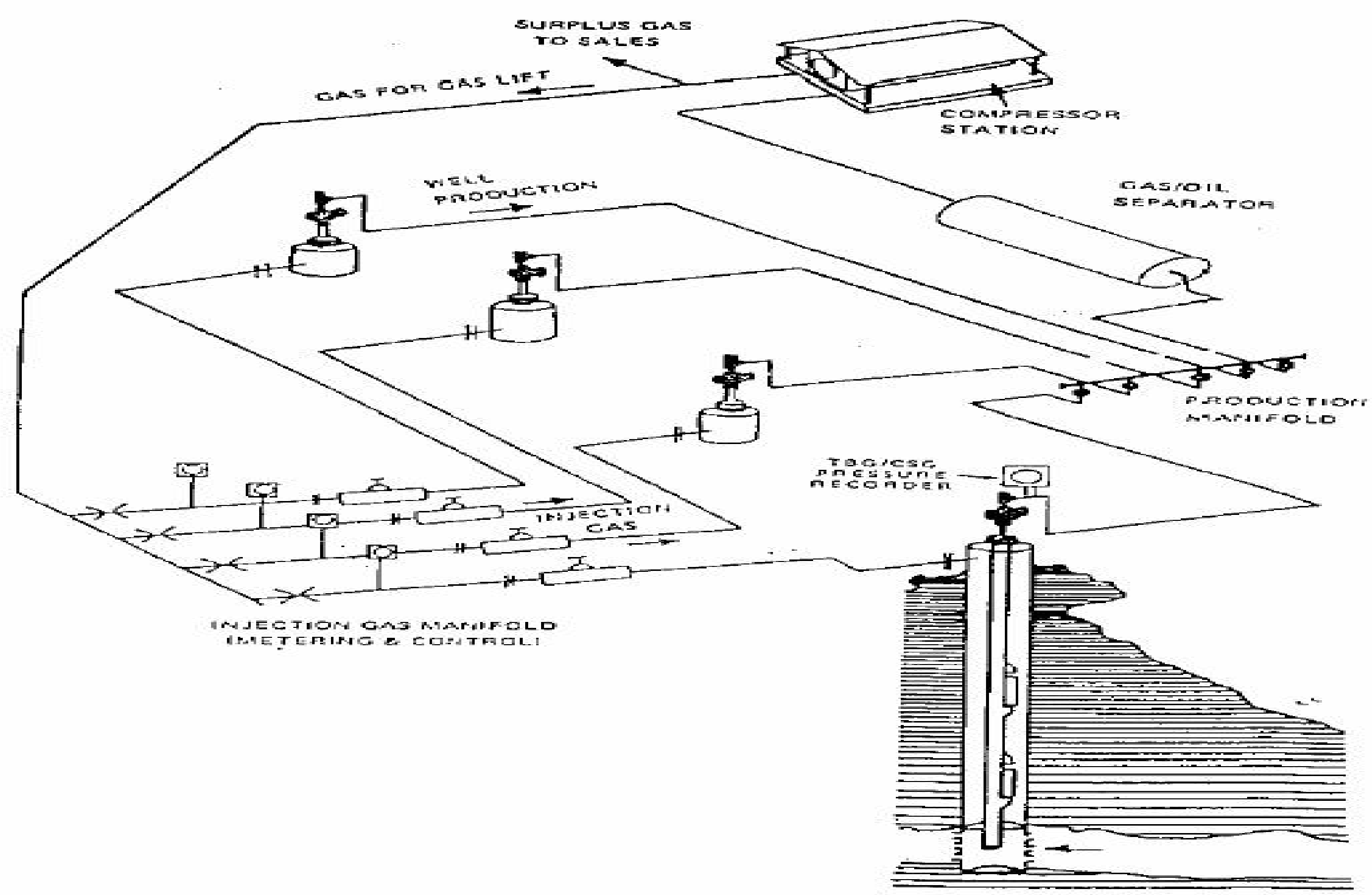


Figure 2. 9: General Gas Lift System

2.7 Mechanisms of Gas Lift

- Gas lift works by injecting high-pressure gas (typically natural gas) from the surface down the annulus and into the production tubing via Gas Lift Valves (GLVs) [Edih et al., 2022].

- Aeration & Density Reduction: The injected gas mixes with the produced liquid in the tubing, creating a gas-liquid mixture. Since gas is much lighter than liquid, the density (ρ) of the mixture is significantly reduced [Amadichuku, 2024].

- Pressure Gradient Reduction: The reduced density lowers the hydrostatic pressure gradient (pressure loss per unit depth) in the tubing.

- Increased Drawdown: This reduction in the tubing pressure loss lowers the flowing bottom-hole pressure (P_{wf}). A lower (P_{wf}) creates a greater pressure differential (drawdown) between the reservoir pressure (P_{res}) and the wellbore, allowing the reservoir to push fluids into the wellbore at a higher rate [Amadichuku, 2024].

2.8 The Core Principles of Gas Lift

2.8.1 Hydrostatic pressure reduction

The total pressure required to lift a column of fluid from the bottom hole to the surface (P_{lift}) is governed primarily by three components:

$$P_{lift} = P_{hydrostatic} + P_{friction} + P_{kinetic}$$

The hydrostatic pressure, $P_{hydrostatic}$, is the most dominant component, representing the weight of the fluid column. It is directly proportional to the fluid density (ρ) and the true vertical depth (H):

$$P_{hydrostatic} = \rho \text{ x } g \text{ x } H$$

2.8.2 Vertical lift performance analysis

In flow assurance and artificial lift design (like in PROSPER), the effect of gas injection is visualized using the Vertical Lift Performance (VLP) curve in conjunction with the Inflow Performance Relationship (IPR) curve.

- VLP Curve: Plots the required flowing bottom-hole pressure (P_{wf}) versus the liquid flow rate (Q_L) to lift the fluid to the surface.

- IPR Curve: Plots the well's ability to produce, showing the liquid flow rate (Q_L) the reservoir can deliver versus the flowing bottom-hole pressure (P_{wf}).

The Gas Lift Effect on VLP:

- Injecting gas effectively shifts the VLP curve down and to the right.
- This shift means that for any given production rate (Q_L), less pressure (P_{wf}) is required at the bottomhole to lift the fluid.
- The new operating point (the intersection of the IPR and the gas-lifted VLP) will result in a higher production rate compared to the original natural flow VLP curve.

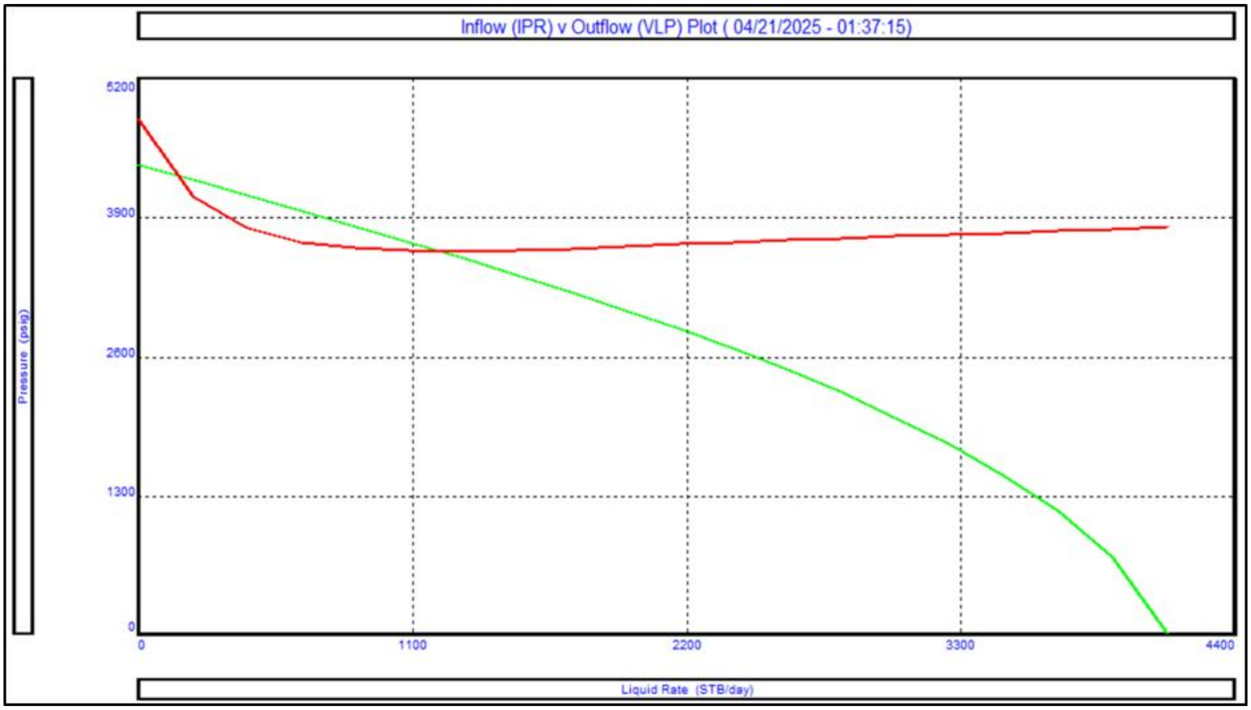


Figure 2. 10: IPR & VLP Curves for Naturally Flowing Well (MB21) (Rolan, 2012)

Figure 2.10 shows the IPR and VLP curves for a naturally flowing well with zero percentage water cut. The IPR (Red curve) shows the reservoir's ability, indicating high potential if the bottomhole pressure (P_{wf}) is low. The VLP (Green curve) shows the pressure required to lift the fluid, with its steepness indicating a heavy fluid column.

The well's current natural operating point (intersection) is severely constrained, resulting in a low flow rate of approximately 500 STB/day at a high P_{wf} of about 3,800 psig. This high P_{wf} is required to overcome the Outflow (VLP) constraint. Since the reservoir's Inflow (IPR) has potential for much higher rates, the well is an ideal candidate for Gas Lift. The goal of the simulation will be to inject gas to shift the VLP curve downward and to the right, reducing P_{wf} and maximizing the sustainable flow rate.

2.9 Basic Theory of Gas Lift

The main thing that must be considered when producing oil wells is to determine how much flow rate can be obtained based on reservoir pressure. The resulting flow rate will illustrate the magnitude of the deliverability of a productive formation. Fluid found in porous media can flow to the wellbore if there is a pressure difference. Reservoir deliverability also affects the type of complexity and the artificial lift method used (Guo & William, 2007).

Inflow Performance Relationship (IPR) is used to evaluate reservoir deliveries in production techniques. Furthermore, the IPR curve is a presentation of the relationship between the pressure of the bottom well that flows and the rate of liquid production (Ariadji & Regina, 2001). At the multiphase Inflow Performance Rate (IPR), it is assumed that there is no skin in the formation and it has a mechanism to drive the water drive in the reservoir.

Vertical Lift Performance (VLP) is the ability of a well to produce a constant surface pressure limit. In flowing wells, this is called tubing intake or outflow performance (Sibeudu, S.O. , 2015). The fluid flow in this tubing is a simultaneous flow of free gas and liquid, both of which can be mixed homogeneously or liquid in the form of a slug, which is driven by a gas column.

Gas lift is a process of lifting the well fluid to the surface by injecting gas through the annular tubing-casing under certain pressure and temperature conditions (Ebrahimi, 2010). The main purpose of a well is to do a gas lift injection to get the expected production rate through a decrease in the fluid flow pressure gradient in the tubing.

The nature of this liquid indicates its resistance to flow. This is an important property used in equations and flow processes. This is a dynamic property because it can only be measured if the fluid moves. Viscosity is a number that represents the force of attraction caused by the pulling force in the adjacent liquid layer. This can be considered as internal friction between molecules, separated from the liquid and the pipe wall.

The term interface indicates a boundary or line dividing between two immiscible phases. The types of interfaces include: liquid-gas, liquid-liquid, liquid-solid, solid-gas, and solid-solid. For fluids, molecular interactions at the interface produce measurable voltages which, if constant, are proportional to the surface free energy needed to form the interface area unit. For cases where the liquid is in contact with air or steam from the liquid, the force per unit length is needed to form a surface area commonly referred to as surface tension. Interfacial tension is used to describe the quantity of two liquids or liquid solids. Interfacial tension between two immiscible liquids is usually smaller than the surface tension liquid with a higher voltage and often intermediate between the surface tension of two liquids (W. Lyons, 2010).

2.10 Operating Modes for Gas Lift

2.10.1 Continuous Gas Lift (CGL)

Continuous-flow gas lift is the only method of artificial lift that fully utilizes the energy in the formation gas production (Rolan 2012). Most wells are gas lifted by continuous flow, which can be considered an extension of natural flow by supplementing the formation gas with additional high-pressure gas from an outside source. Gas is injected continuously into the production conduit at a maximum depth on the basis of the available injection gas pressure.

The injection gas mixes with the produced well fluids and decreases the flowing pressure gradient of the mixture from the point of gas injection to the surface. The lower bowing pressure gradient reduces the flowing bottomhole pressure (BHFP) to establish the drawdown required for attaining a design production rate from the well. In a typical gas lift system, compressed gas is injected through gas lift mandrels and valves into the production string. The injected gas lowers the hydrostatic pressure in the production string to re-establish the required pressure differential between the reservoir and wellbore, thus causing the formation fluids to flow to the surface.

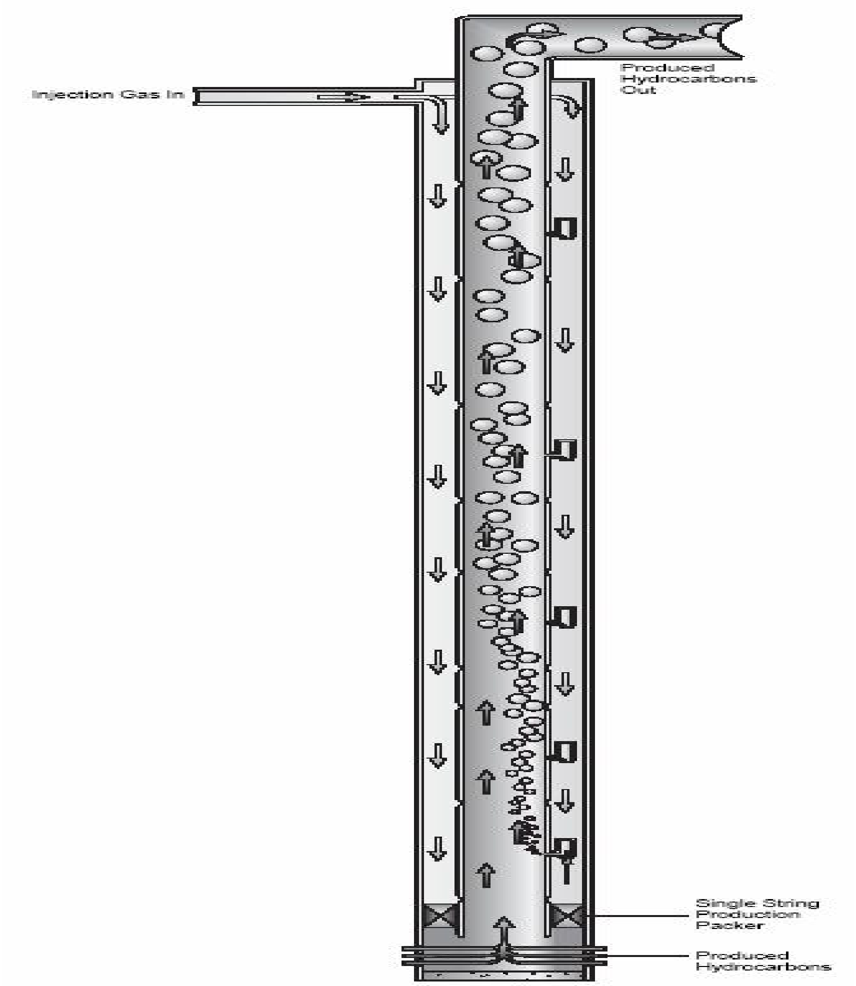


Figure 2. 11: Continuous Gas Lift (Rolan, 2012)

2.10.2 Intermittent Gas Lift (IGL)

If a sufficient drawdown in the bottomhole pressure (BHP) is not possible by continuous flow, intermittent gas lift operation may be used (Rolan 2012). Intermittent gas lift requires high instantaneous gas volumes to displace liquid slugs to the surface. The disadvantage of intermittent lift is an "on-off" need for high-pressure gas, which presents a gas handling problem at the surface and surging in the BHFP that cannot be tolerated in many wells producing sand. Intermittent gas lift operations are particularly difficult to regulate and to operate efficiently in smaller closed rotative systems with limited gas storage capacities in the low- and high-pressure lines.

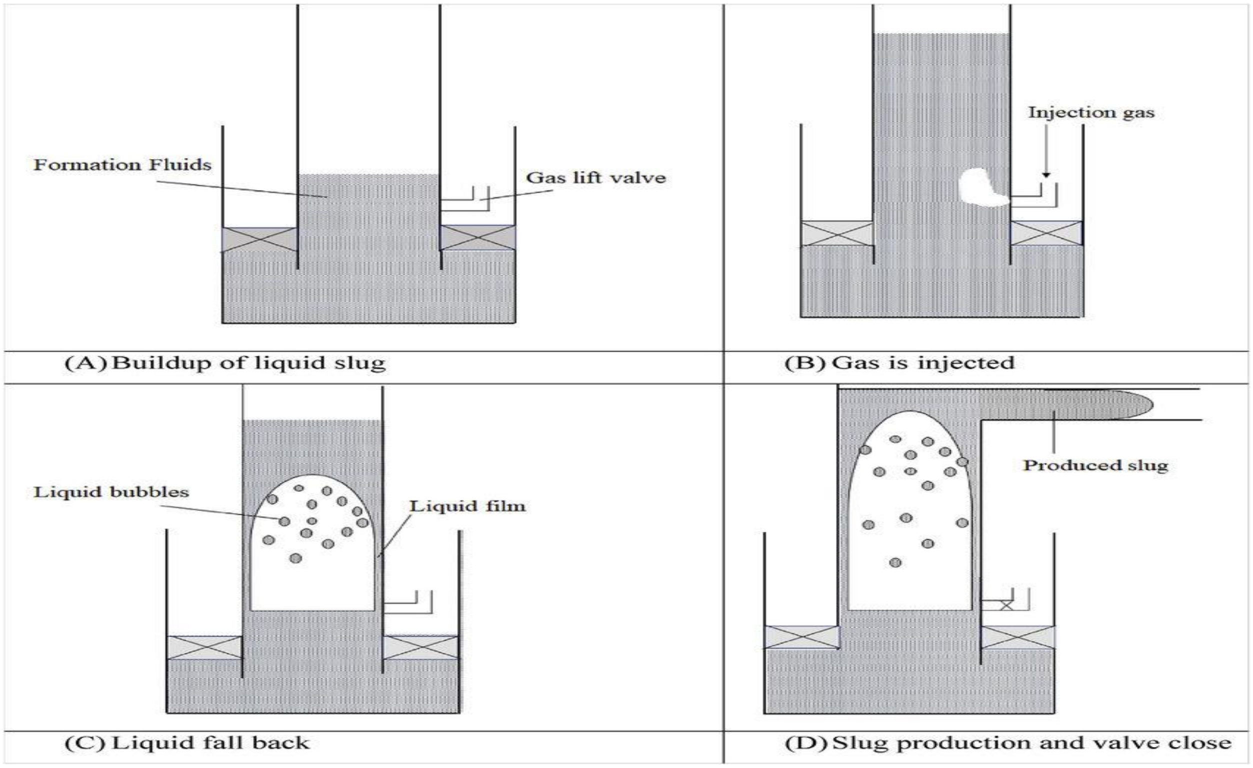


Figure 2. 12: Intermittent gas lift cycle

2.11 Multiphase Flow Correlations (The PROSPER Engine)

While the VLP curve is the graphical representation of the required pressure to lift fluid to the surface, its shape and position are determined by the application of multiphase flow correlations. The calculation of the pressure gradient is the fundamental mechanism that generates the VLP curve. This calculation requires accurate modeling of the transient behavior and various flow regimes present in the wellbore, including bubble flow, slug flow, churn flow, and annular flow.

Commonly used correlations within PROSPER for VLP calculation include Hagedorn and Brown, Beggs and Brill, or Duns and Ros. The choice of correlation is critical, as inaccuracies can lead to major errors in the predicted VLP curve and the final production rate. Therefore, correlation selection is usually based on specific well conditions, such as well deviation, fluid type, and gas-liquid ratio.

2.12 Research Gaps

Despite the extensive body of literature on gas lift technology and its applications in petroleum production, several gaps remain that limit the optimization of gas lift systems, particularly in the context of naturally flowing wells transitioning to artificial lift:

- Limited Comparative Analysis for Naturally Flowing Wells: Most existing studies focus on gas lift optimization for wells already on artificial lift or compare methods after field implementation. There is limited literature on proactive, simulation-based comparative analysis of intermittent versus continuous gas lift for naturally flowing wells before they require artificial lift intervention. The Buzurgan field study (Hatif et al., 2025) and Bayan field optimization (Roslan, 2012) demonstrate post-implementation analysis rather than predictive evaluation during the natural flow phase.
- Insufficient Integration of Multiple Performance Metrics: While previous studies have evaluated gas lift performance, most focus on single metrics such as production rate or gas injection efficiency independently. Comprehensive comparative studies that simultaneously evaluate oil production rates, optimum gas injection rates, system stability, and operational efficiency for both intermittent and continuous methods using modern simulation tools are scarce. The Buzurgan study demonstrated production recovery from 0 to 396.6 STB/day but focused primarily on continuous gas lift optimization. The Bayan

study addressed field-wide optimization but did not provide a detailed well-by-well comparison of intermittent versus continuous methods. A systematic approach that evaluates both methods against multiple performance criteria for the same well conditions would provide more robust decision-making guidance.

- Limited Documentation of PROSPER-Based Comparative Studies: While PROSPER is widely recognized as an industry-standard tool for well performance analysis, published case studies specifically comparing intermittent and continuous gas lift using PROSPER remain limited in academic literature. Most PROSPER applications documented in the literature focus on single-method optimization rather than comparative evaluation. The available studies (Hatif et al., 2025; Roslan, 2012) demonstrate PROSPER's capability for gas lift design but do not provide a detailed comparative analysis of both injection modes for the same well. This gap limits the availability of validated methodologies and benchmarking data for engineers undertaking similar comparative studies.
- Inadequate Consideration of Well-Specific Optimization: Generic selection criteria exist for choosing between continuous and intermittent gas lift (based on productivity index, reservoir pressure, etc.), but detailed, well-specific optimization studies that account for unique reservoir characteristics, fluid properties, and completion configurations are limited. The literature often provides general guidelines rather than specific methodologies for tailoring gas lift method selection to individual well conditions. The sensitivity analysis performed in the Buzurgan study (showing effects of gas specific gravity, water cut, and injection depth) demonstrates the importance of well-specific parameters. Still, similar comprehensive analyses comparing both gas lift methods for the same set of well conditions are not extensively documented.

2.13 Conclusion

Gas lift has proven to be an effective technique for sustaining production in naturally flowing wells as reservoir pressure declines. By reducing the hydrostatic pressure in the production tubing, gas lift improves inflow performance and increases oil output. The study demonstrates that selecting the optimal injection rate and operating strategy is crucial for maximizing efficiency. When supported with nodal analysis and economic evaluation, gas lift can extend well life, enhance recovery, and reduce production decline. Overall, gas lift remains a flexible and reliable artificial lift method for optimizing performance in marginally flowing wells.

CHAPTER 3

METHODOLOGY

This chapter outlines the systematic approach employed to achieve the objectives of this study, which aims to evaluate and compare the performance of intermittent and continuous gas lift injection methods for a naturally flowing well using PROSPER simulation software. The methodology encompasses the study design, data collection procedures, software selection and justification, well model development process, simulation procedures, and analytical framework used to compare the performance of both gas lift methods.

The research adopts a simulation-based approach using PROSPER, an industry-standard well performance analysis tool. This approach enables a comprehensive evaluation of both gas lift methods under identical well conditions, eliminating confounding variables that would exist in sequential field implementations. The methodology follows a structured workflow that progresses from data collection through model development, validation, simulation, and comparative analysis.

3.1 Description of Gas Lift Implementation

Gas lift is implemented by injecting compressed gas into the annulus between the casing and production tubing. The gas enters the tubing through gas-lift valves installed at specific depths. Once injected, the gas mixes with the produced fluid, reducing its density and lowering the hydrostatic pressure inside the tubing. This allows reservoir fluids to flow more easily to the surface.

In continuous gas lift, gas is injected steadily to maintain a consistent reduction in density, resulting in stable production flow. In intermittent systems, gas is injected in cycles to periodically unload accumulated liquids in low-rate wells. The selection between continuous and intermittent operation depends on reservoir deliverability, well productivity, and available surface facilities.

3.2 Software Selection and Justification

3.2.1 PROSPER software overview

PROSPER is a Production and System Performance analysis software. It assists the production or reservoir engineer to predict tubing and pipeline hydraulics and temperature with accuracy and speed. Prosper's powerful sensitivity calculation features enable existing designs to be optimized. It helps petroleum producers to maximize their production earnings by providing the means of critically analyzing the performance of each producing well.

3.2.2 Key capabilities of PROSPER

- Prediction of tubing and pipeline hydraulics with high accuracy
- Calculation of pressure and temperature profiles along the wellbore
- Modeling of various artificial lift methods, including gas lift
- Nodal analysis for system optimization
- Sensitivity analysis for parametric studies
- PVT modeling and matching capabilities
- IPR (Inflow Performance Relationship) modeling
- VLP (Vertical Lift Performance) calculation using multiple correlations

3.2.3 Justification of PROSPER selection

PROSPER was selected for this study based on the following considerations:

- Industry Standard: PROSPER is widely recognized and used by petroleum companies globally for well performance analysis and artificial lift design. Its credibility is established through extensive field validation and industry acceptance.
- Comprehensive Modeling: PROSPER provides integrated modeling of all well system components (reservoir inflow, wellbore hydraulics, surface facilities), enabling holistic performance evaluation.
- Gas Lift Capabilities: PROSPER includes dedicated modules for both continuous and intermittent gas lift design and optimization, making it ideal for comparative analysis of these methods.
- Correlation Library: The software includes extensive libraries of multiphase flow correlations, PVT correlations, and IPR models, allowing selection of the most appropriate correlations for the specific well conditions.
- Nodal Analysis: PROSPER's nodal analysis capability enables the determination of optimal operating points by matching reservoir inflow performance with wellbore outflow performance.
- Sensitivity Analysis: Built-in sensitivity analysis features facilitate the evaluation of how changes in key parameters affect system performance.
- Validation Capability: PROSPER allows matching of simulated results with measured field data, ensuring model accuracy before using it for predictive analysis.
- Previous Successful Applications: The literature review identified successful applications of PROSPER for gas lift studies, including the Buzurgan field study (Hatif et al., 2025) and Bayan field optimization (Roslan, 2012), validating its suitability for this research.

3.3 Research Design

This study employs a quantitative, simulation-based comparative analysis research design. The research is structured around the following key components:

3.3.1 Study type

The study is a case study analysis focusing on a single naturally flowing oil well. This approach allows for detailed, in-depth evaluation of both gas lift methods under specific, well-characterized reservoir and completion conditions. The case study methodology is appropriate for this research because it enables:

- Detailed examination of well-specific parameters and their effects on gas lift performance
- Controlled comparison where both methods are evaluated using identical input data
- Comprehensive analysis of multiple performance metrics simultaneously
- Generation of actionable recommendations specific to the well under study

3.3.2 Research approach

The research follows a deductive approach, applying established gas lift principles, nodal analysis theory, and well performance concepts to the specific case study well. The study progresses systematically through:

1. Model Development: Building a comprehensive well model using actual or representative field data
2. Validation: Ensuring the model accurately represents the well's current natural flow performance

3. Simulation: Applying both intermittent and continuous gas lift configurations to the validated model
4. Optimization: Determining optimal gas injection rates for each method
5. Comparison: Evaluating performance differences based on defined metrics
6. Recommendation**:** Identifying the superior method based on simulation results

3.3.3 Study variables

1. **Independent Variables (Manipulated)**

- Gas lift method (intermittent vs. continuous)
- Gas injection rate (varied systematically to find optimum)
- Injection depth (evaluated in sensitivity analysis)

2. **Dependent Variables (Measured/Predicted)**

- Oil production rate (STB/day)
- Flowing bottom-hole pressure (psia)
- System stability indicators
- Gas utilization efficiency

3. **Controlled Variables (Held constant)**

- Reservoir properties (pressure, temperature, permeability)
- Fluid properties (PVT characteristics, GOR, water cut)
- Well completion (tubing size, depth, configuration)
- Surface facilities constraints

3.4 Data Collection

3.4.1 Data requirement

To develop an accurate well model in PROSPER, comprehensive data covering reservoir characteristics, fluid properties, well completion details, and production performance were required. The following categories of data are essential in the figure below:

Figure 3. 1: Required data for the model

3.5 Preparation of Well Model in PROSPER

The well models in this work were prepared using the PROSPER program. PROSPER makes a model for each component of the producing well system separately, which contributes to overall performance, and then allows for verifying each model subsystem by performance matching. In this way, the program ensures that the calculation is as accurate as possible. Once the system model has been tuned to real data, PROSPER is confidently used to model the well in different scenarios and to make forward predictions of reservoir pressure based on surface production data.

3.6 Simulation Study Cases

Three different scenarios were considered using the available well. The process is organized into the following sequence:

3.6.1 Case 1: Naturally flowing well model

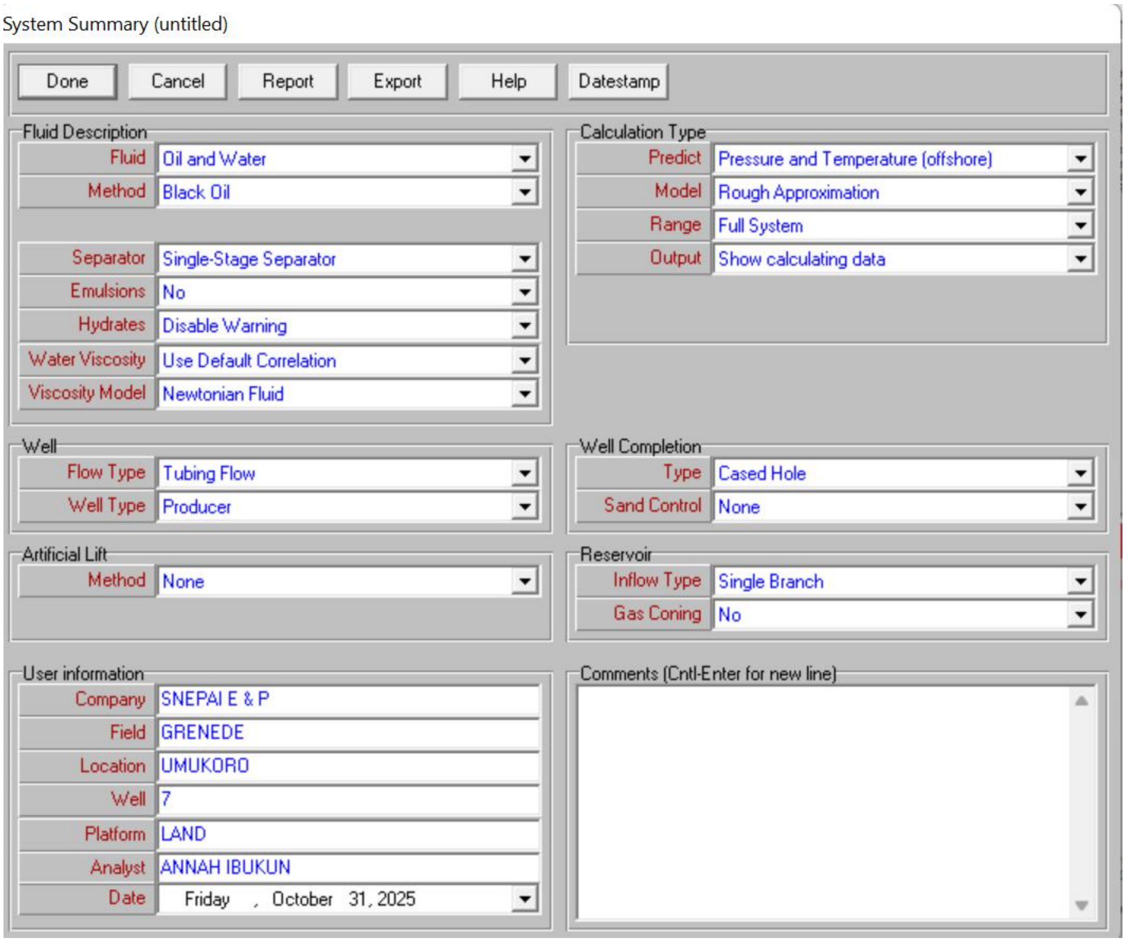
3.6.1.1 System setup

A. Project Initialization

- A new PROSPER project file is set up
- Basic well information and identification are set up
- Calculation preferences and unit system are set up

B. System summary

- Well name and Identification are input.
- Well type is defined (producer)
- Fluid type is specified (black oil)
- The artificial lift method is defined as none since the model is for a naturally flowing well



Fluid Description

Fluid	Oil and Water
Method	Black Oil
Separator	Single-Stage Separator
Emulsions	No
Hydrates	Disable Warning
Water Viscosity	Use Default Correlation
Viscosity Model	Newtonian Fluid

Calculation Type

Predict	Pressure and Temperature (offshore)
Model	Rough Approximation
Range	Full System
Output	Show calculating data

Well

Flow Type	Tubing Flow
Well Type	Producer

Well Completion

Type	Cased Hole
Sand Control	None

Artificial Lift

Method	None

Reservoir

Inflow Type	Single Branch
Gas Coning	No

User information

Company	SNEPAI E & P
Field	GRENEDE
Location	UMUKORO
Well	7
Platform	LAND
Analyst	ANNAH IBUKUN
Date	Friday , October 31, 2025

Comments (Cntl-Enter for new line)

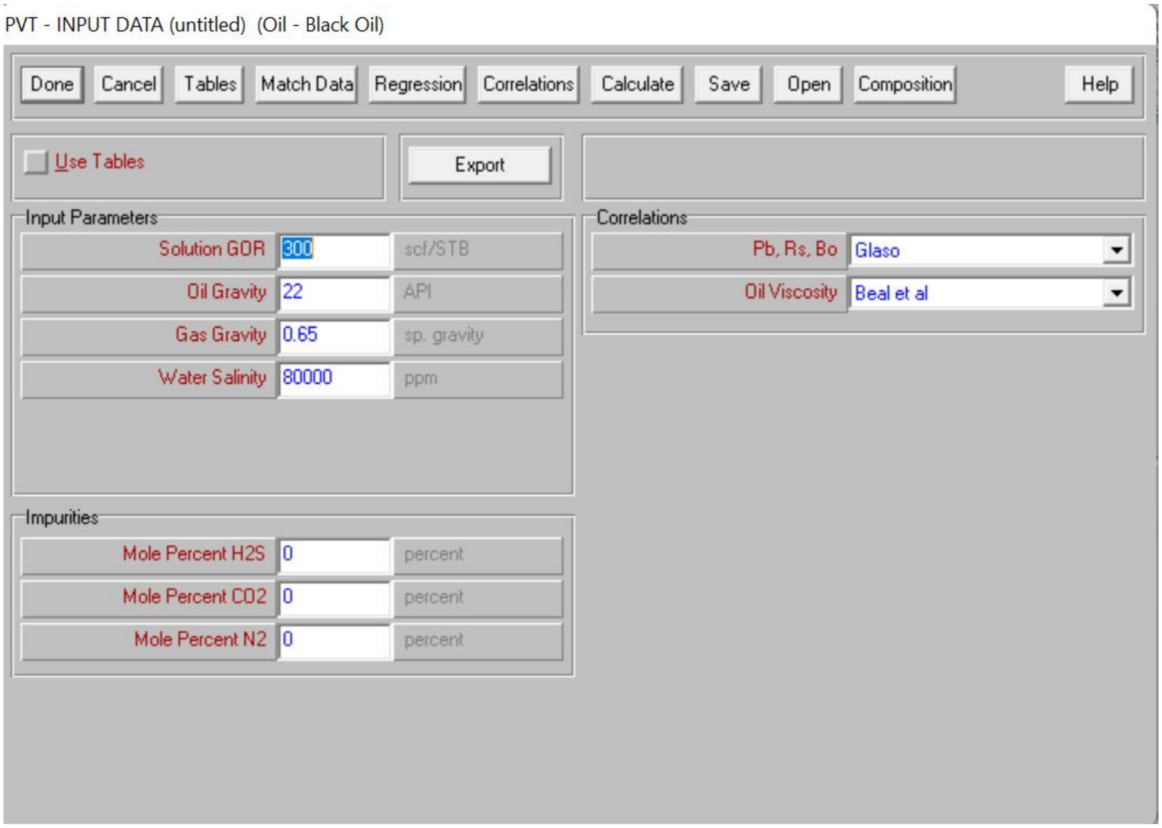
Figure 3. 2: System Summary

3.6.1.2 PVT data input

The PVT (Pressure-Volume-Temperature) data section is critical, as all pressure and flow calculations depend on accurate predictions of fluid properties. The following data are entered in the table below:

Table 3. 1 : PVT data

Solution GOR (scf/STB)	300
Oil gravity (API)	22
Gas gravity	0.65
Water salinity (ppm)	80000
Mole percent H_2S (percent)	0
Mole percent CO_2 (percent)	0
Mole percent N_2 (percent)	0



PVT - INPUT DATA (untitled) (Oil - Black Oil)

☐ Use Tables

Input Parameters

Solution GOR	300	scf/STB
Oil Gravity	22	API
Gas Gravity	0.65	sp. gravity
Water Salinity	80000	ppm

Impurities

Mole Percent H2S	0	percent
Mole Percent CO2	0	percent
Mole Percent N2	0	percent

Correlations

Pb, Rs, Bo	Glaso
Oil Viscosity	Beal et al

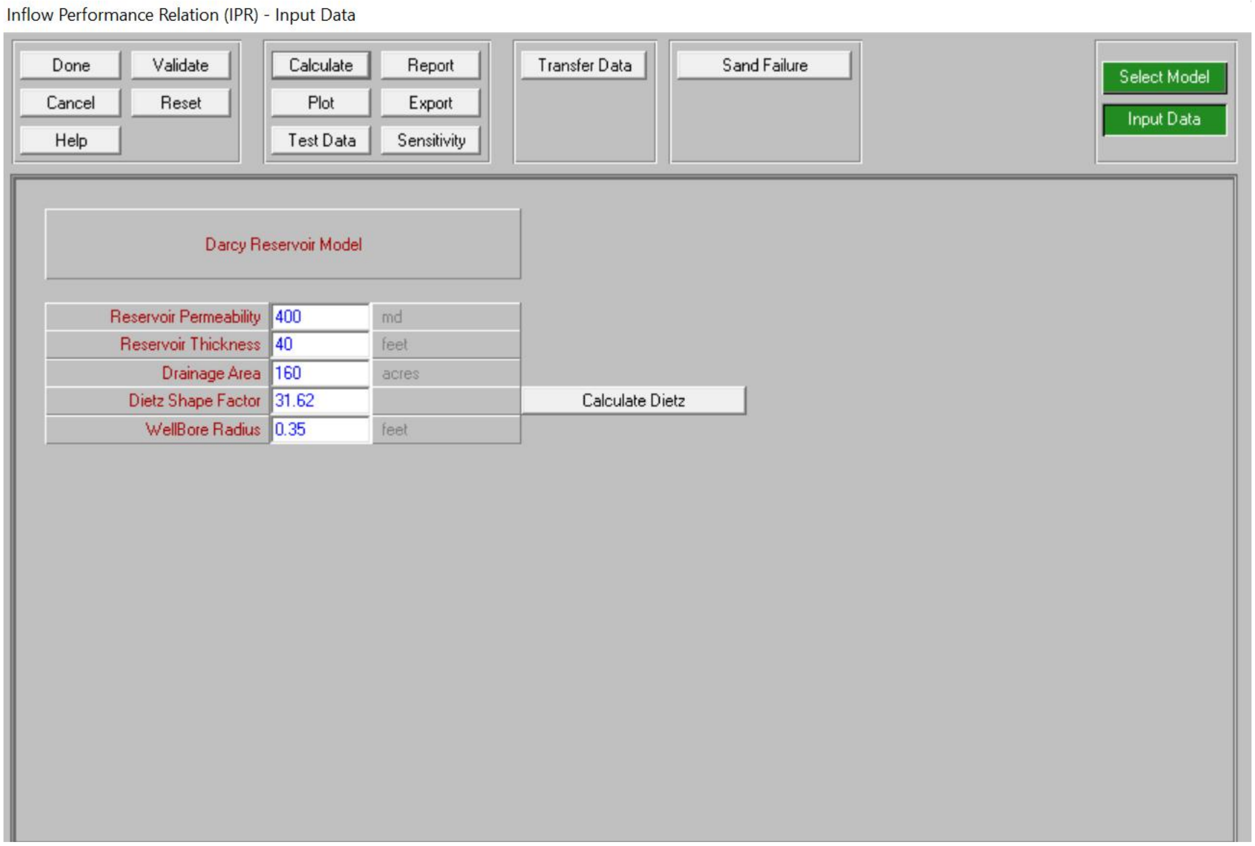
Figure 3. 3: PVT input data

3.6.1.3 Inflow Performance Relationship (IPR) modeling

The IPR describes the well's ability to deliver fluids from the reservoir as a function of bottom-hole flowing pressure. The IPR model used to plot the IPR is Darcy’s plot, as it is based on the available data. The data used is given in the table below:

Table 3. 2 : Input data for IPR modeling

Reservoir pressure (psig)	4500
Reservoir temperature (°F)	150
Water cut (percent)	10
Total GOR (scf/STB)	300
Reservoir permeability (md)	400
Reservoir thickness (ft)	40
Skin	3
Drainage area (acres)	160
Dietz shape factor	31.62
Wellbore radius (ft)	0.35



Darcy Reservoir Model

Reservoir Permeability 400 md
Reservoir Thickness 40 feet
Drainage Area 160 acres
Dietz Shape Factor 31.62
WellBore Radius 0.35 feet

Figure 3. 4: IPR input data

3.6.1.4 Equipment data

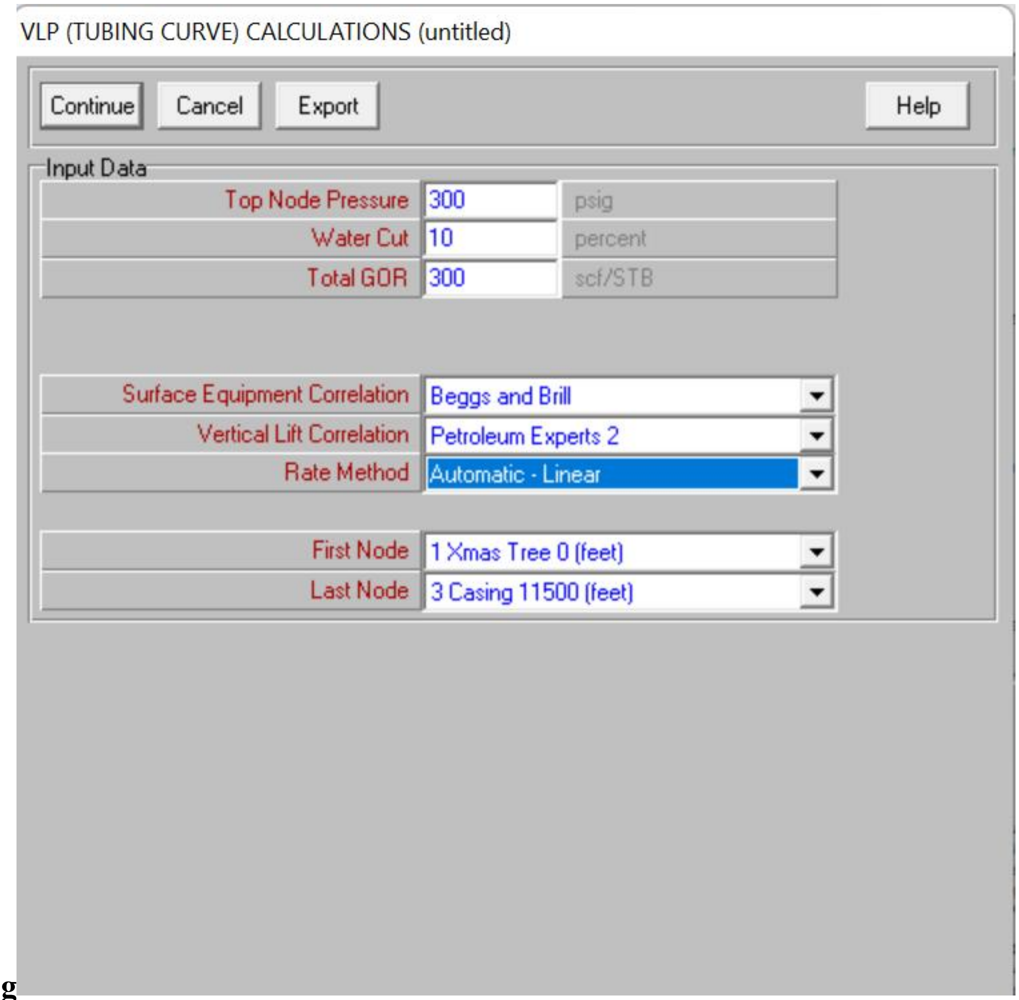
Deviation survey, downhole equipment, geothermal gradient, and average heat capacities are modeled with the data below:

Table 3. 3: Equipment data input

True vertical depth (TVD)	11500
Tubing depth	10800
Tubing internal diameter (in)	2.441
Tubing inside roughness (in)	0.001
Casing internal diameter (in)	8.435

Casing inside roughness (in)	0.001
Oil average heat capacity (Btu/lb/F)	0.53
Gas average heat capacity (Btu/lb/F)	0.51
Water average heat capacity (Btu/lb/F)	1
Overall heat transfer coefficient (Btu/h/ft^2/F)	0.88

3.6.1.5 Vertical Lift Performance Modeling (VLP)



Top Node Pressure: 300 psig
Water Cut: 10 percent
Total GOR: 300 scf/STB

Surface Equipment Correlation: Beggs and Brill
Vertical Lift Correlation: Petroleum Experts 2
Rate Method: Automatic - Linear

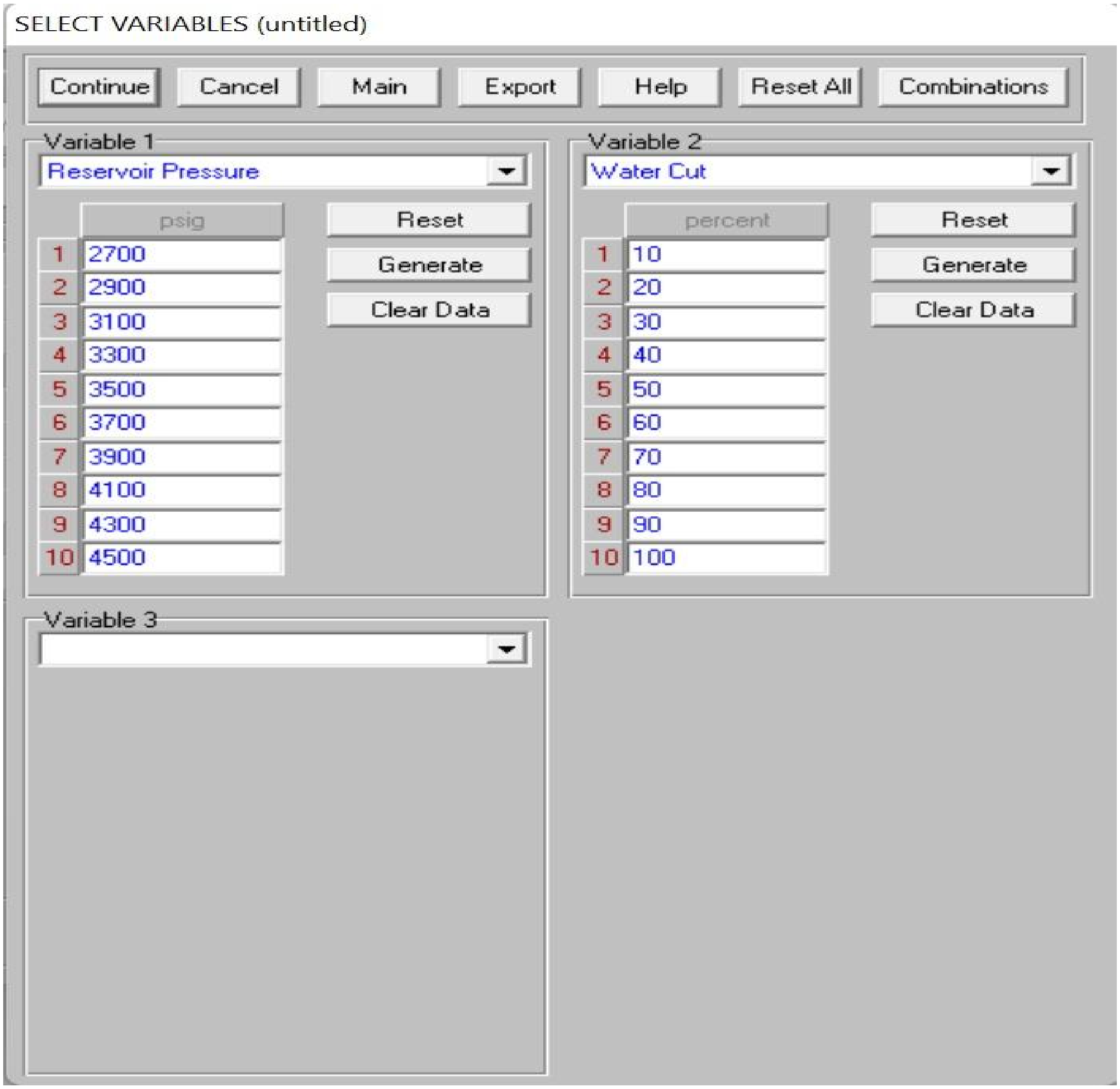
First Node: 1 Xmas Tree 0 (feet)
Last Node: 3 Casing 11500 (feet)

modeling

Figure 3. 5: VLP input data

3.6.1.6 Sensitivity analysis

Sensitivity analysis is done to demonstrate that as reservoir pressure declines and water cut increases, the naturally flowing well will eventually cease production, justifying the need for artificial lift intervention. Reservoir pressure is varied systematically to represent progressive depletion, and water cut is varied to represent progressive water encroachment.



Variable 1: Reservoir Pressure

Variable 2: Water Cut

	psig	percent
1	2700	10
2	2900	20
3	3100	30
4	3300	40
5	3500	50
6	3700	60
7	3900	70
8	4100	80
9	4300	90
10	4500	100

Figure 3. 6: Sensitivity analysis between various reservoir pressures and water cut

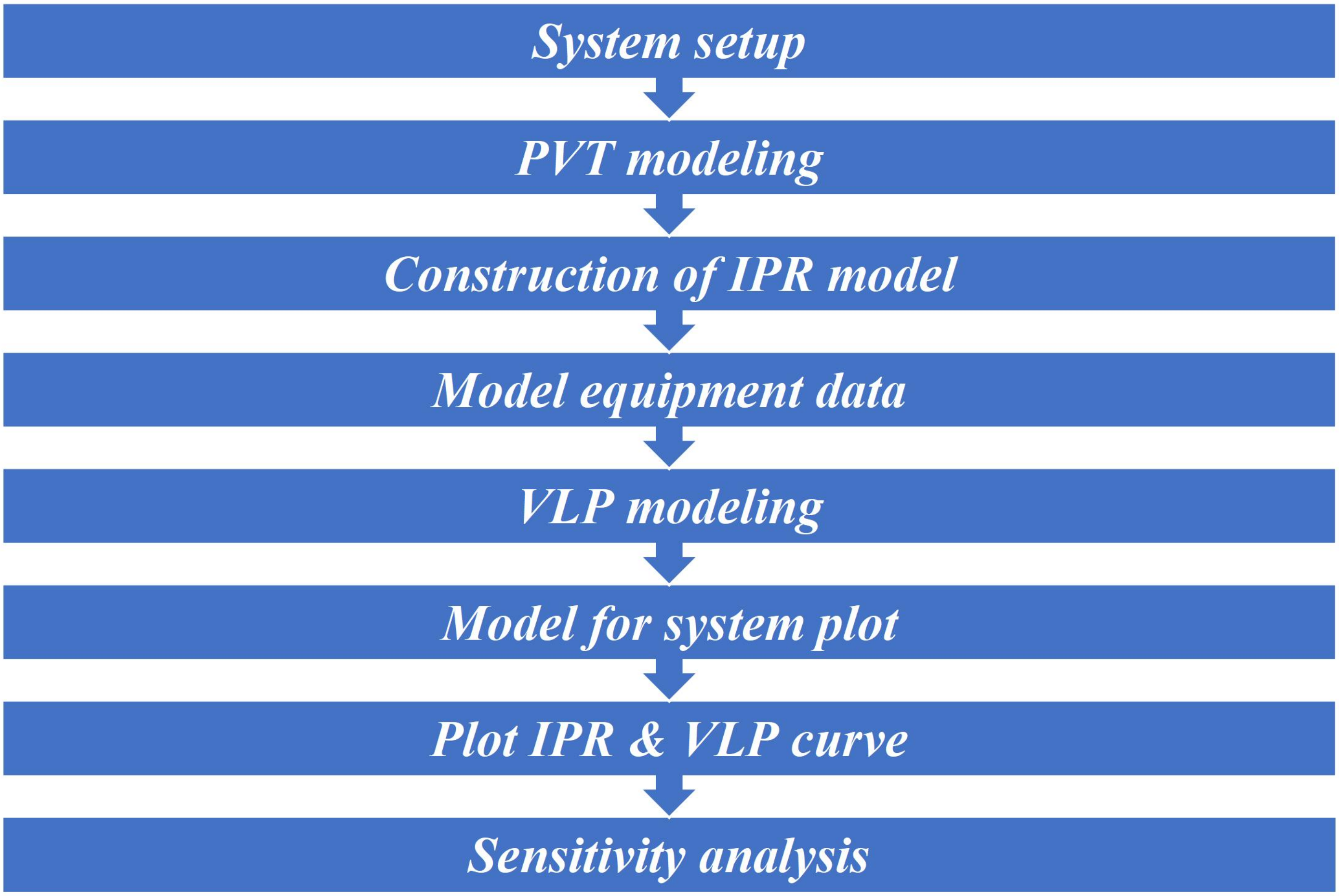


Figure 3. 7: Process chart for a natural flowing well model

3.6.2 Case 2: Continuous gas lift model

The modeling of continuous gas lift for the selected naturally flowing well was carried out using the PROSPER well performance simulation software. The following steps were adopted to evaluate the effect of continuous gas injection on well productivity:

i. Data Acquisition and Preparation: Reservoir and well data, including reservoir pressure, fluid properties (API gravity, GOR, and water cut), tubing dimensions, and well geometry, were collected and validated. These parameters served as input for both inflow and outflow simulations.

ii. PVT Modeling: The PVT module in PROSPER was configured using standard correlations to estimate temperature- and pressure-dependent fluid properties such as formation volume factor, viscosity, density, and solution gas–oil ratio. The PVT model was tuned to available field data.

iii. Construction of Inflow Performance Relationship (IPR): The inflow performance of the reservoir was modeled using Darcy's radial steady-state flow equation. Darcy inflow was selected because the dataset provided assumed single-phase flow conditions above bubble-point pressure, with key reservoir properties such as permeability, net pay thickness, drainage area, water cut, and solution gas–oil ratio. These parameters correspond to a constant productivity index scenario, justifying the use of a linear inflow model. The productivity index was used to generate the IPR curve, which served as input for nodal analysis and subsequent gas-lift performance simulations.

iv. Vertical Lift Performance (VLP) Modeling: Multiphase flow correlations (Beggs and Brill/Hagedorn-Brown) were applied to predict pressure losses along the tubing string. A geothermal gradient was specified to account for temperature variations with depth. The VLP curve was constructed and matched with actual production trends.

v. Selection of Continuous Gas Lift Design: The gas-lift mode was set to continuous injection in PROSPER. Injection gas properties, surface injection pressure, available injection rate, and expected valve depth were defined. The initial injection depth was selected near the point of maximum pressure reduction in the tubing.

vi. Gas-Lift Valve Configuration: Preliminary valve spacing, opening pressures, and check-valve functions were selected using the automatic valve design tool in PROSPER. The valve depth was iteratively adjusted to minimize backpressure and improve reservoir drawdown.

vii. Nodal Analysis Under Gas-Lift Injection: Nodal (IPR–VLP) analysis was performed to determine the operating point of the well at different gas-injection rates. Multiple simulations were conducted under varying tubing head pressures and gas injection rates.

viii. Optimization of Injection Gas Rate: A sensitivity study was carried out to determine the optimum injection rate. The optimum point was defined as the injection rate that produced the maximum incremental oil production before the onset of diminishing returns.

ix. Sensitivity Analysis: Further simulations were conducted to evaluate the effect of changes in water cut, gas-oil ratio, injection depth, and tubing-head pressure on the well's performance.

x. Model Validation and Result Extraction: Model results were compared with actual well behavior (where available). Final outputs, including production rate, flowing bottom-hole pressure, pressure–temperature profiles, and gas-utilization efficiency, were exported for interpretation in the Results and Discussion chapter.

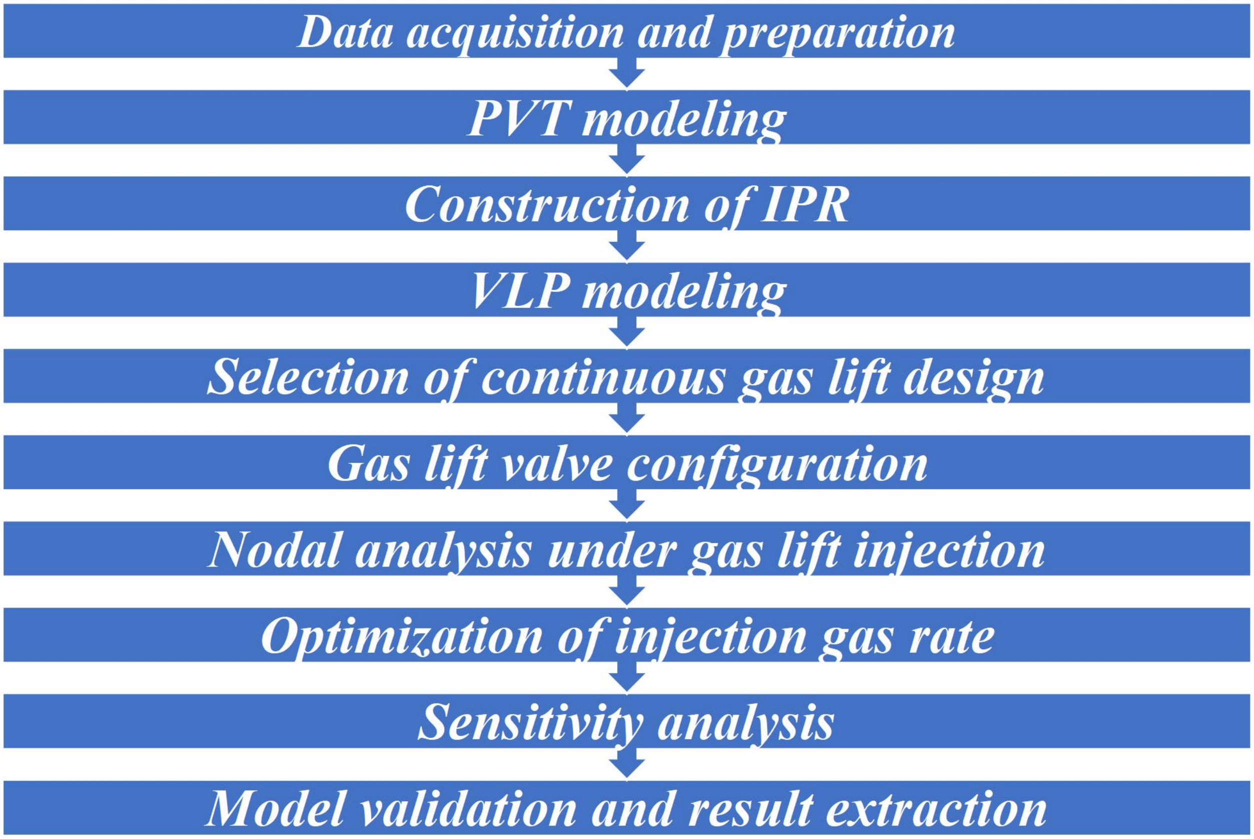


Figure 3. 8: Process chart for a natural flowing well model

3.6.3 Case 3: Intermittent gas lift model

The methodology adopted for evaluating intermittent gas lift performance in the selected naturally flowing well involved a structured workflow comprising data preparation, model configuration, validation, and comparative simulation. The following steps were implemented:

i. Data Collection and Fluid Property Input: The production data provided (reservoir pressure, productivity index, water cut, gas–oil ratio, and PVT properties) were collated and input into PROSPER. Deviation survey, downhole equipment, geothermal gradient, and average heat capacities dimensions were also incorporated to ensure a realistic wellbore representation.

ii. Generation of Inflow Performance Relationship (IPR): The Inflow Performance Relationship for the well was generated using Darcy's equation, based on the supplied reservoir and well parameters.

iii. Vertical Lift Performance Modeling: The VLP model was configured in PROSPER using multiphase flow correlations. This established the outflow characteristics of the well as a function of liquid rate, gas injection rate, and tubing geometry.

iv. Configuration of Intermittent Gas Lift: Intermittent gas lift was modeled by selecting the appropriate gas-lift cycle options in PROSPER. The following key parameters were defined:

    - Surface injection pressure
    - Injection depth
    - Gaslift gas gravity
    - Valve port size
    - Tubing liquid level

v. Valve design: Gas-lift valves were designed to ensure proper gas injection control throughout the wellbore. A constant surface closing pressure (CSCP) design approach was adopted for valve sizing and depth selection. The value of the surface casing head pressure is 200psig less than the surface injection pressure.

vi. Performance Prediction and Output Analysis: PROSPER simulations generated liquid production rate (STB/d), gas injection requirement (scf/stb), estimated daily oil recovery, cycle efficiency, and productivity improvement. These results were exported for comparison against continuous gas lift performance.

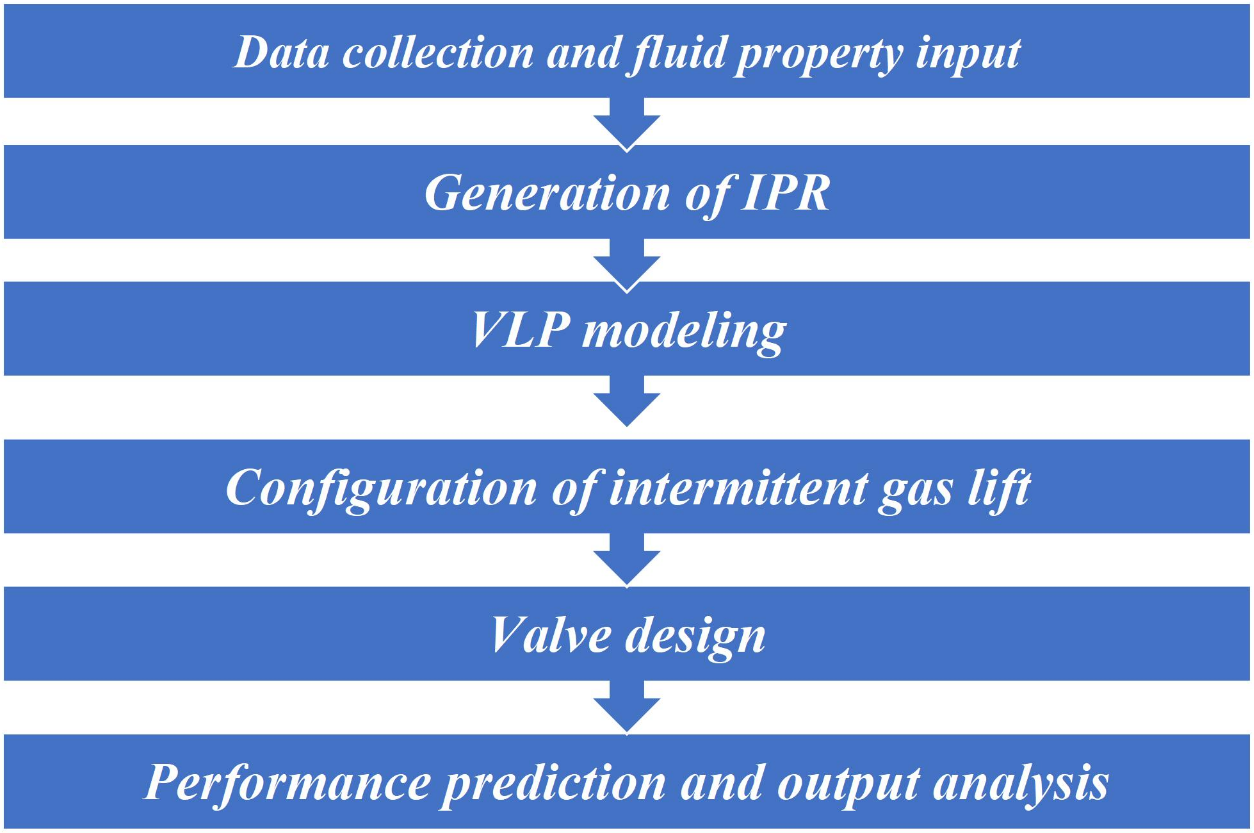


Figure 3. 9: Process chart for intermittent gas lift model

CHAPTER 4

RESULTS AND DISCUSSION

This chapter presents the results obtained from the PROSPER simulation-based comparative analysis of intermittent and continuous gas lift injection methods for the case study well.

4.1 CASE 1: NATURALLY FLOWING WELL

4.1.1 WELL SCHEMATIC

Figure 4.1 shows that the well is a cased hole with a single tubing completion. It utilizes 2.44in tubing from the surface (Xmas Tree) down to 10,800ft. The well is completed with an 8.44 in casing from 10,800ft down to the true vertical depth of 11,500ft.

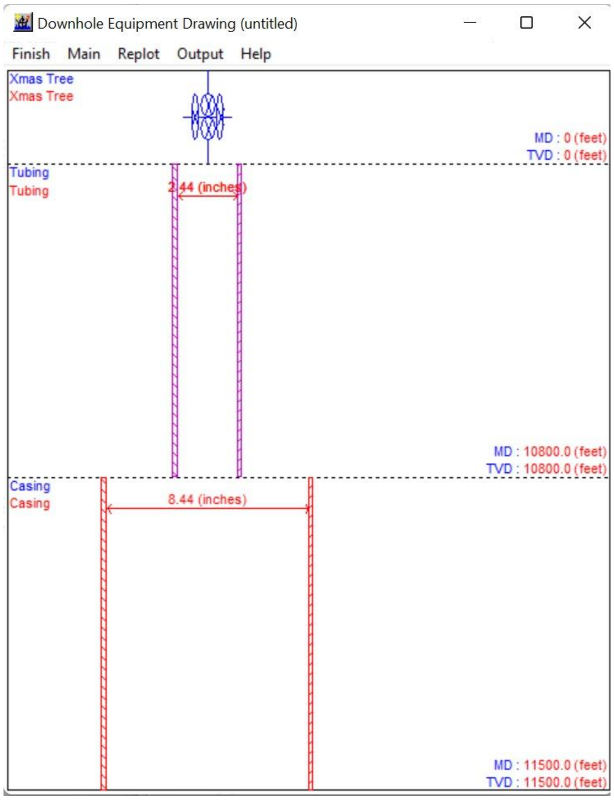
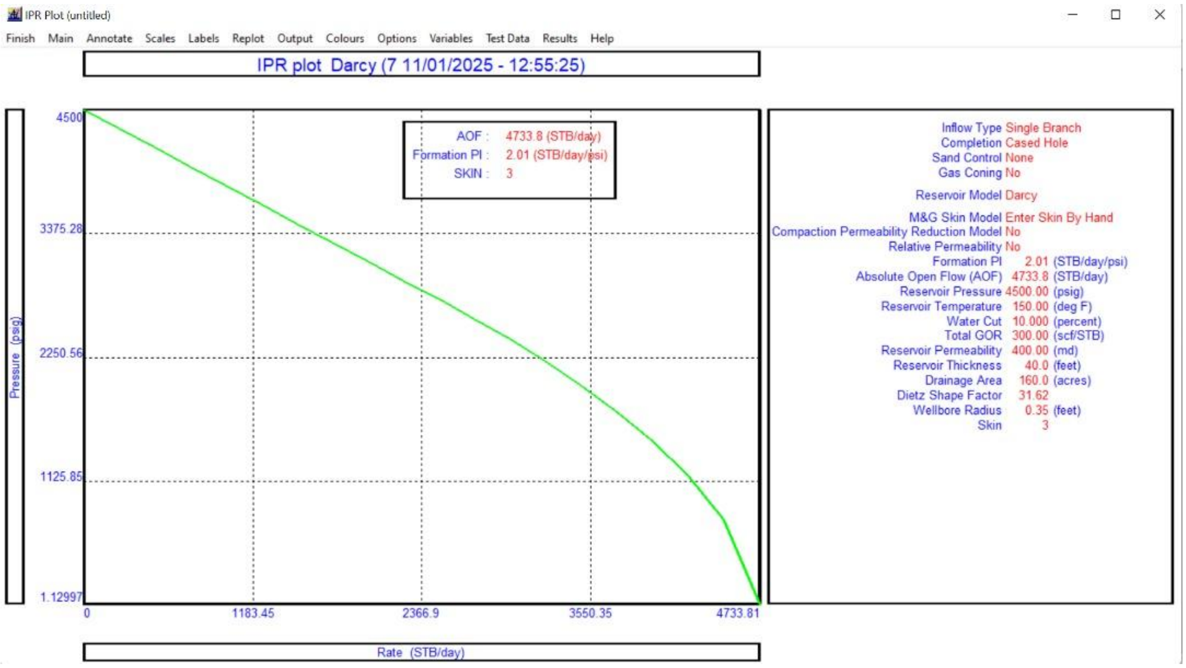


Figure 4. 1: Well schematic

4.1.2 IPR & VLP CURVES

The performance of the naturally flowing well was analyzed. This analysis involves plotting the VLP against the reservoir's ability to deliver fluids IPR to determine the optimum operating point.



AOF : 4733.8 (STB/day)
Formation PI : 2.01 (STB/day/psi)
SKIN : 3

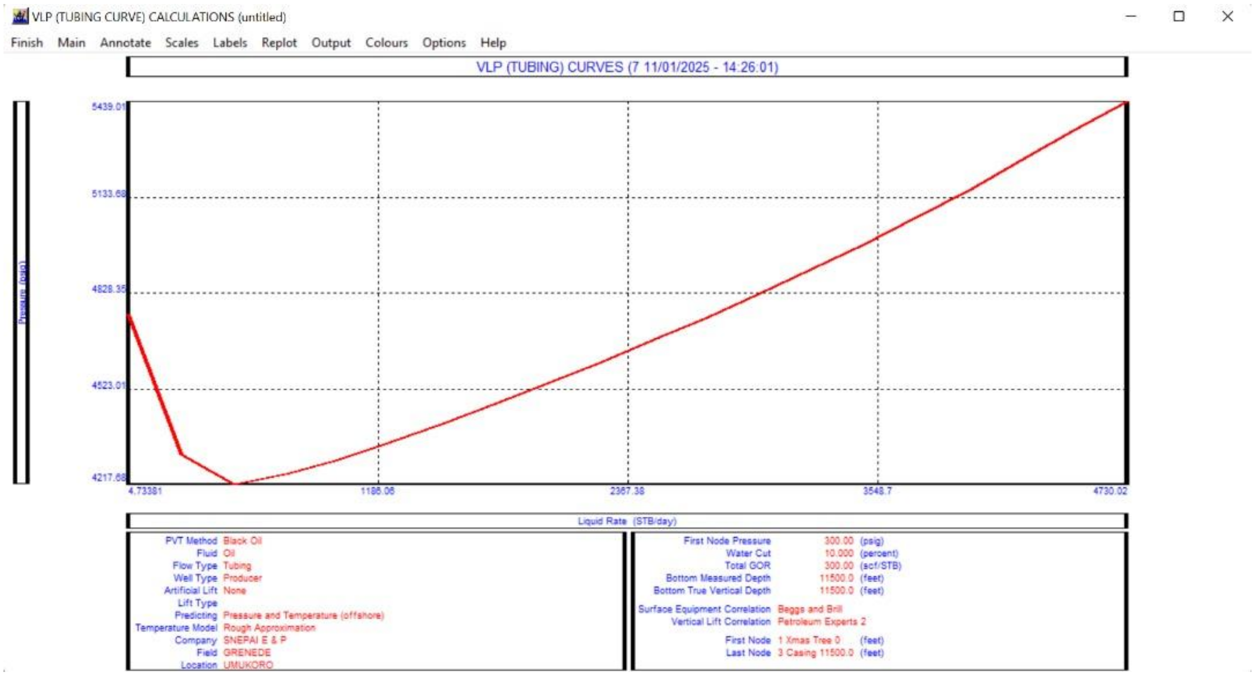
Inflow Type Single Branch
Completion Cased Hole
Sand Control None
Gas Coning No

Reservoir Model Darcy

M&G Skin Model Enter Skin By Hand
Compaction Permeability Reduction Model No
Relative Permeability No
Formation PI 2.01 (STB/day/psi)
Absolute Open Flow (AOF) 4733.8 (STB/day)
Reservoir Pressure 4500.00 (psig)
Reservoir Temperature 150.00 (deg F)
Water Cut 10.000 (percent)
Total GOR 300.00 (scf/STB)
Reservoir Permeability 400.00 (md)
Reservoir Thickness 40.0 (feet)
Drainage Area 160.0 (acres)
Dietz Shape Factor 31.62
Wellbore Radius 0.35 (feet)
Skin 3

Figure 4. 2: IPR plot

From Figure 4.2, the Absolute Open Flow (AOF) potential is 4,733.8 STB/day. This represents the well's maximum potential under current reservoir conditions. The Productivity Index (PI) is 2.01STB/day. This means that for every 1psi of pressure drawdown from the reservoir pressure of 4500 psi, the well can produce an additional 2.01STB/day. This PI shows that the well is a low-productivity well, necessitating the need for gas lift later.



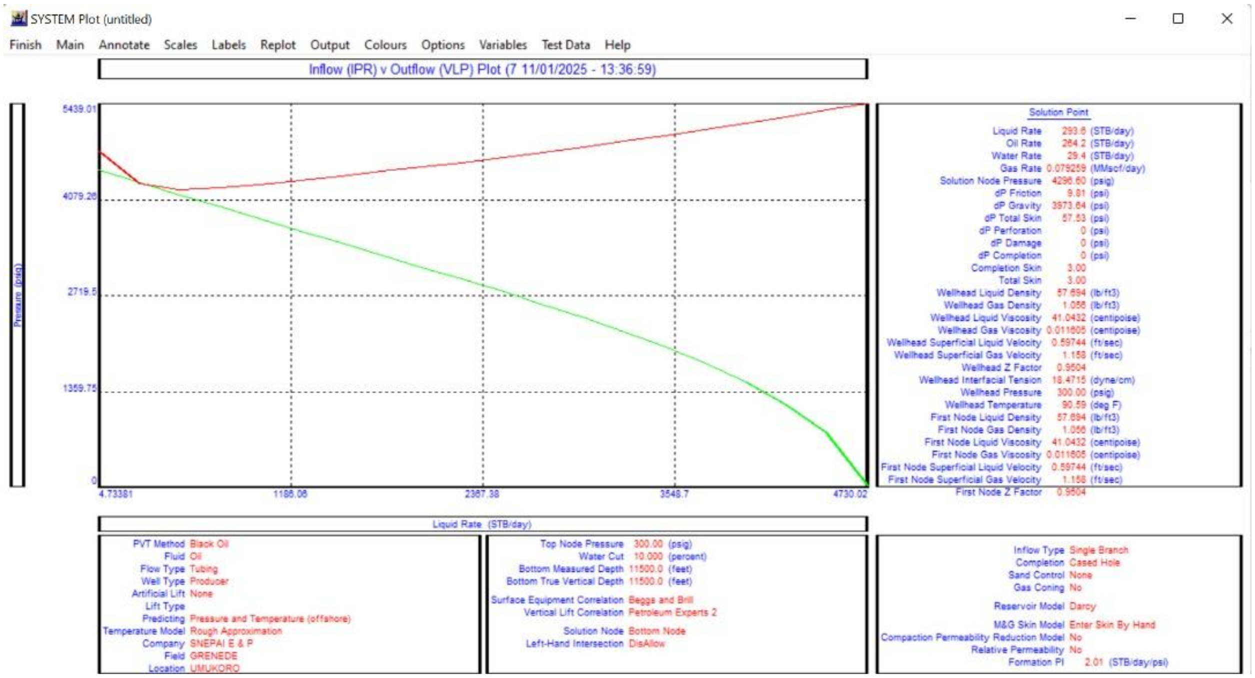
PVT Method Black Oil
Fluid Oil
Flow Type Tubing
Well Type Producer
Artificial Lift None
Lift Type
Predicting Pressure and Temperature (offshore)
Temperature Model Rough Approximation
Company SNEPAI E & P
Field GRENEDE
Location UMUKORO

First Node Pressure 300.00 (psig)
Water Cut 10.000 (percent)
Total GOR 300.00 (scf/STB)
Bottom Measured Depth 11500.0 (feet)
Bottom True Vertical Depth 11500.0 (feet)
Surface Equipment Correlation Beggs and Brill
Vertical Lift Correlation Petroleum Experts 2
First Node 1 Xmas Tree 0 (feet)
Last Node 3 Casing 11500.0 (feet)

Figure 4. 3: VLP plot

The IPR & VLP plot below shows the operating point of the well. The red curve represents the IPR curve, while the green curve represents the VLP curve. At this point, the pressure required to lift the fluid equals the pressure supplied by the reservoir, thus defining the only stable flow condition. The Nodal Analysis demonstrates that the well is capable of natural flow. The stable operating point is 264.2STB/day at a bottom-hole flowing pressure of 4076.26psi.

This rate is achieved with a total pressure drawdown of 423.74psi. This drawdown is relatively low, indicating that while the well is flowing naturally, there is still significant potential that could be unlocked by reducing the bottom-hole pressure, which can be done by implementing gas lift.



Solution Point

Liquid Rate	293.6	(STB/day)
Oil Rate	264.2	(STB/day)
Water Rate	29.4	(STB/day)
Gas Rate	0.079259	(MMscf/day)
Solution Node Pressure	4296.60	(psig)
dP Friction	9.81	(psi)
dP Gravity	3973.64	(psi)
dP Total Skin	57.53	(psi)
dP Perforation	0	(psi)
dP Damage	0	(psi)
dP Completion	0	(psi)
Completion Skin	3.00	
Total Skin	3.00	
Wellhead Liquid Density	57.694	(lb/ft3)
Wellhead Gas Density	1.056	(lb/ft3)
Wellhead Liquid Viscosity	41.0432	(centipoise)
Wellhead Gas Viscosity	0.011605	(centipoise)
Wellhead Superficial Liquid Velocity	0.59744	(ft/sec)
Wellhead Superficial Gas Velocity	1.158	(ft/sec)
Wellhead Z Factor	0.9504	
Wellhead Interfacial Tension	18.4715	(dyne/cm)
Wellhead Pressure	300.00	(psig)
Wellhead Temperature	90.59	(deg F)
First Node Liquid Density	57.694	(lb/ft3)
First Node Gas Density	1.056	(lb/ft3)
First Node Liquid Viscosity	41.0432	(centipoise)
First Node Gas Viscosity	0.011605	(centipoise)
First Node Superficial Liquid Velocity	0.59744	(ft/sec)
First Node Superficial Gas Velocity	1.156	(ft/sec)
First Node Z Factor	0.9504	

PVT Method	Black Oil
Fluid	Oil
Flow Type	Tubing
Well Type	Producer
Artificial Lift	None
Lift Type	
Predicting	Pressure and Temperature (offshore)
Temperature Model	Rough Approximation
Company	SNEPAI E & P
Field	GRENEDE
Location	UMUKORO

Top Node Pressure	300.00 (psig)
Water Cut	10.000 (percent)
Bottom Measured Depth	11500.0 (feet)
Bottom True Vertical Depth	11500.0 (feet)
Surface Equipment Correlation	Beggs and Brill
Vertical Lift Correlation	Petroleum Experts 2
Solution Node	Bottom Node
Left-Hand Intersection	DisAllow

Inflow Type	Single Branch
Completion	Cased Hole
Sand Control	None
Gas Coning	No
Reservoir Model	Darcy
M&G Skin Model	Enter Skin By Hand
Compaction Permeability Reduction Model	No
Relative Permeability	No
Formation PI	2.01 (STB/day/psi)

Figure 4. 4: IPR & VLP curve

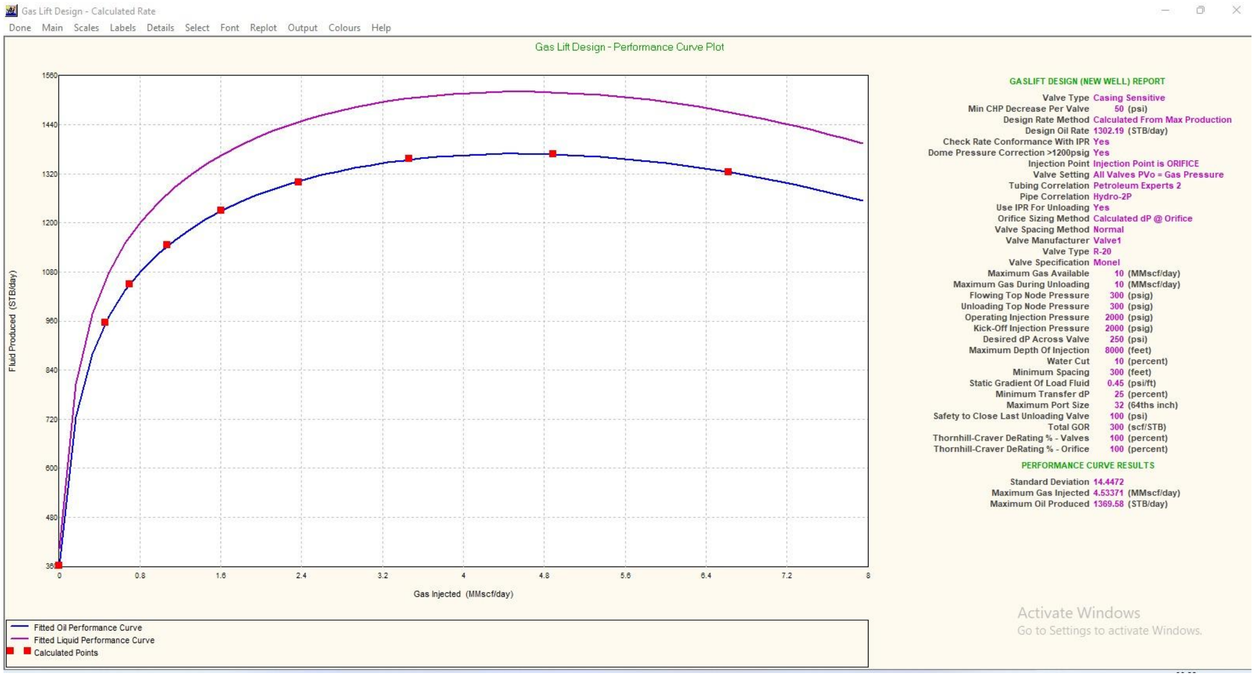
The analysis reveals that the well is currently flowing naturally at 264.2STB/day. While the well is flowing, this rate represents only 6.2% of its maximum potential of 4733.8 STB/day.

4.2 CASE 2: CONTINUOUS FLOW GAS LIFT MODEL

4.2.1 GAS LIFT PERFORMANCE CURVE (GLPC)

Figure 4.5 shows the Gas Lift Performance Curve is a plot of the Total Liquid or Oil Produced versus the Gas Injected. As the gas injection rate increases from zero, the production rate increases rapidly. The blue curve represents the oil performance curve, while the purple curve is the liquid performance curve. From 0MMSCF/day injected, the rate is the natural flow rate (264.2STB/day), which is consistent with the Nodal Analysis.

The curve reaches a peak point at 4.53371MMscf/day. This point represents the design gas injection rate where the well achieves its design production rate at 1369.58STB/day. Considering cost, the optimum injection rate is 1.0MMscf/day because the production rate difference from the design production rate is minimal. Hence, the optimum production rate is approximately 1100STB/day, which is a 76% increase over the flow rate when the well was flowing naturally.



GASLIFT DESIGN (NEW WELL) REPORT

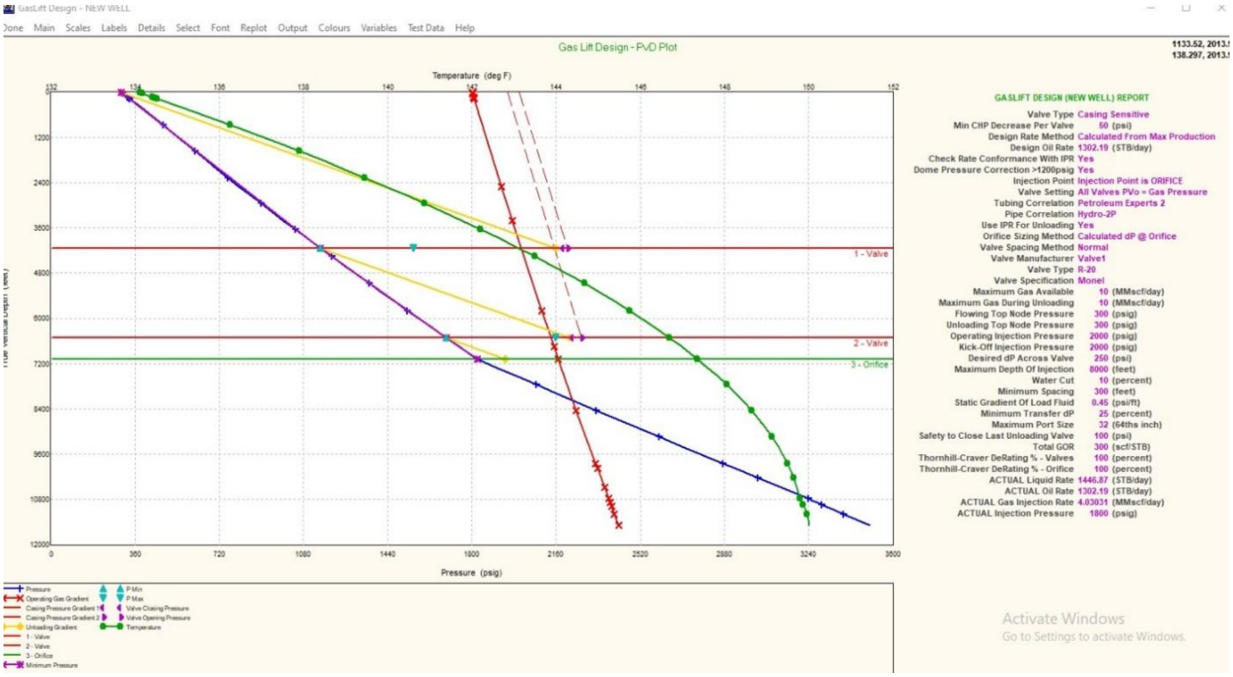
Valve Type	Casing Sensitive
Min CHP Decrease Per Valve	50 (psi)
Design Rate Method	Calculated From Max Production
Design Oil Rate	1302.19 (STB/day)
Check Rate Conformance With IPR	Yes
Dome Pressure Correction >1200psig	Yes
Injection Point	Injection Point is ORIFICE
Valve Setting	All Valves PVo = Gas Pressure
Tubing Correlation	Petroleum Experts 2
Pipe Correlation	Hydro-2P
Use IPR For Unloading	Yes
Orifice Sizing Method	Calculated dP @ Orifice
Valve Spacing Method	Normal
Valve Manufacturer	Valve1
Valve Type	R-20
Valve Specification	Monel
Maximum Gas Available	10 (MMscf/day)
Maximum Gas During Unloading	10 (MMscf/day)
Flowing Top Node Pressure	300 (psig)
Unloading Top Node Pressure	300 (psig)
Operating Injection Pressure	2000 (psig)
Kick-Off Injection Pressure	2000 (psig)
Desired dP Across Valve	250 (psi)
Maximum Depth Of Injection	8000 (feet)
Water Cut	10 (percent)
Minimum Spacing	300 (feet)
Static Gradient Of Load Fluid	0.45 (psi/ft)
Minimum Transfer dP	25 (percent)
Maximum Port Size	32 (64ths inch)
Safety to Close Last Unloading Valve	100 (psi)
Total GOR	300 (scf/STB)
Thornhill-Craver DeRating % - Valves	100 (percent)
Thornhill-Craver DeRating % - Orifice	100 (percent)

PERFORMANCE CURVE RESULTS

Standard Deviation	14.4472
Maximum Gas Injected	4.53371 (MMscf/day)
Maximum Oil Produced	1369.58 (STB/day)

Figure 4. 5: Gas Lift Performance Curve

Figure 2.6 shows the design of the gas lift valves. Here we have two valves and an orifice. The first valve is set at a depth of approximately 3500ft, while the second valve is at 8500ft and the orifice is at a depth of 7200ft.



GASLIFT DESIGN (NEW WELL) REPORT

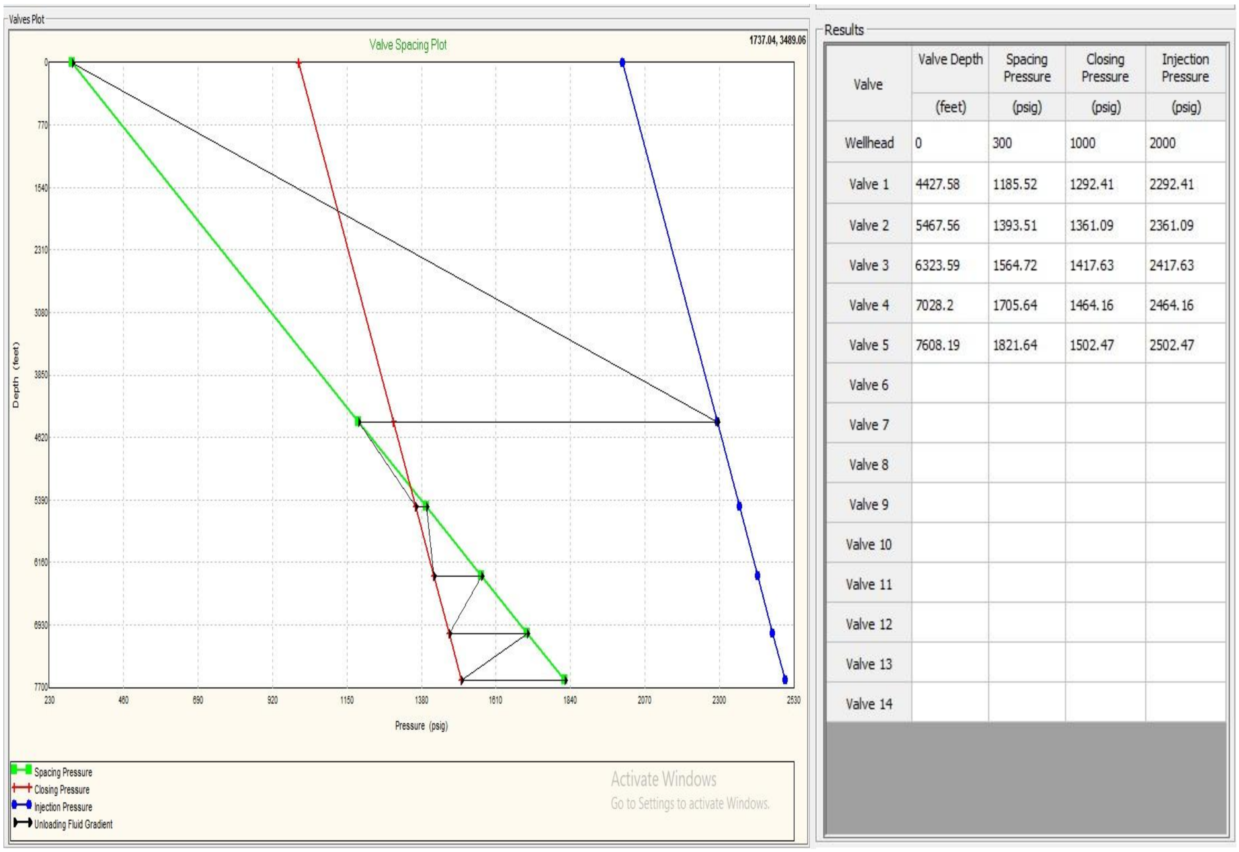
Valve Type	Casing Sensitive
Min CHP Decrease Per Valve	50 (psi)
Design Rate Method	Calculated From Max Production
Design Oil Rate	1302.19 (STB/day)
Check Rate Conformance With IPR	Yes
Dome Pressure Correction >1200psig	Yes
Injection Point	Injection Point is ORIFICE
Valve Setting	All Valves PVo = Gas Pressure
Tubing Correlation	Petroleum Experts 2
Pipe Correlation	Hydro-2P
Use IPR For Unloading	Yes
Orifice Sizing Method	Calculated dP @ Orifice
Valve Spacing Method	Normal
Valve Manufacturer	Valve1
Valve Type	R-20
Valve Specification	Monel
Maximum Gas Available	10 (MMscf/day)
Maximum Gas During Unloading	10 (MMscf/day)
Flowing Top Node Pressure	300 (psig)
Unloading Top Node Pressure	300 (psig)
Operating Injection Pressure	2000 (psig)
Kick-Off Injection Pressure	2000 (psig)
Desired dP Across Valve	250 (psi)
Maximum Depth Of Injection	8000 (feet)
Water Cut	10 (percent)
Minimum Spacing	300 (feet)
Static Gradient Of Load Fluid	0.45 (psi/ft)
Minimum Transfer dP	25 (percent)
Maximum Port Size	32 (64ths inch)
Safety to Close Last Unloading Valve	100 (psi)
Total GOR	300 (scf/STB)
Thornhill-Craver DeRating % - Valves	100 (percent)
Thornhill-Craver DeRating % - Orifice	100 (percent)
ACTUAL Liquid Rate	1446.87 (STB/day)
ACTUAL Oil Rate	1302.19 (STB/day)
ACTUAL Gas Injection Rate	4.03031 (MMscf/day)
ACTUAL Injection Pressure	1800 (psig)

Figure 4. 6: Gas Lift Design

4.3 INTERMITTENT FLOW GAS LIFT MODEL

4.3.1 GAS LIFT VALVE SPACING

Figure 4.7 shows the valve depth, spacing pressure, closing pressure, and injection pressure of the five valves required for intermittent flow gas lift.



Valve	Valve Depth	Spacing Pressure	Closing Pressure	Injection Pressure
	(feet)	(psig)	(psig)	(psig)
Wellhead	0	300	1000	2000
Valve 1	4427.58	1185.52	1292.41	2292.41
Valve 2	5467.56	1393.51	1361.09	2361.09
Valve 3	6323.59	1564.72	1417.63	2417.63
Valve 4	7028.2	1705.64	1464.16	2464.16
Valve 5	7608.19	1821.64	1502.47	2502.47
Valve 6				
Valve 7				
Valve 8				
Valve 9				
Valve 10				
Valve 11				
Valve 12				
Valve 13				
Valve 14				

Figure 4. 7: Valve spacing plot

4.3.2 SIMULATION RESULTS

The Intermittent Gas Lift system was designed for the well to address its low productivity (PI of 2.01STB/day). The results in Table 4.1 confirm the high effectiveness of the Intermittent Gas Lift method for this well:

Table 4. 1: Simulation result done for intermittent flow gas lift

Daily Production Rate (STB/day)	2827.76
Cycle frequency (1/hour)	6.76
Gas injection rate (MMscf/day)	0.026
Downhole pressure (psi)	2469.42
Produced slug volume (STB)	17.4071
Fall back (feet)	1492.44

The design is highly successful. The Intermittent Gas Lift system increases the well's production rate from the natural flow rate of 264.2 STB/day to 2827.76 STB/day, indicating a 90.7% increase. In comparison with continuous flow gas lift, there is an increase from 1100STB/day to 2827.76STB/day, indicating a 61.1% increase.

Also, the intermittent gas lift design made use of 0.026MMscf/day and still brought about a massive increase in production over continuous gas lift, which made use of 1.0MMscf/day.

Input Data

Surface Injection Pressure	2000	psig
Injection Depth	8000	feet
Gaslift Gas Gravity	0.65	sp. gravity
Wellhead Pressure	300	psig
Valve Port Size	32	64ths inch
Water Cut	10	percent
Tubing Liquid Level	3500	feet

Results

Downhole Injection Pressure	2528.45	psig
Downhole Pressure	2469.42	psig
Slug Velocity	9.38673	ft/sec
Bubble Velocity	2.15275	ft/sec
Gas Injection Rate	26.3567	Mscf/day
Fall Back	1492.44	feet
Produced Slug Length	3007.56	feet
Produced Slug Volume	17.4071	STB
Pcasing / Pslug	1.0239	
Produced/Accumulated Slug Length	0.66835	
Starting Slug Length / Valve Depth	0.5625	
Time To Surface	531.861	seconds
Cycle Frequency	6.76868	1/hour
Daily Production Rate	2827.76	STB/day

Figure 4. 8: Intermittent gas lift simulation results

4.4 SUMMARY OF RESULTS

Table 4. 2: Summary of results gotten from the three case scenarios

MODEL	OPTIMUM GAS INJECTED (MMSCF)	OIL PRODUCTION RATE (STB)	% CHANGE FROM BASELINE
NATURALLY FLOWING WELL	0	264.2	0
CONTINUOUS FLOW GAS LIFT	1.0	1100	76
INTERMITTENT FLOW GAS LIFT	0.026	2827.76	90.7

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 CONCLUSION

This study successfully evaluated and compared the performance of intermittent and continuous gas lift injection methods for a naturally flowing well using PROSPER simulation software. The research was motivated by the need to provide systematic, data-driven guidance for gas lift method selection before costly field implementation, thereby eliminating trial-and-error approaches that characterize many operational transitions from natural flow to artificial lift.

The naturally flowing well under study was confirmed to be producing at 264.2 STB/day with a bottom-hole flowing pressure of 4076.26 psi and a productivity index of 2.01 STB/day/psi. While capable of natural flow, the well was operating at only 6.2% of its absolute open flow potential of 4733.8 STB/day, indicating substantial untapped productive capacity constrained by insufficient pressure drawdown. This established the technical justification for artificial lift intervention.

The comparative simulation analysis yielded definitive results that clearly differentiate the performance characteristics of both gas lift methods:

- **Continuous gas lift** demonstrated solid performance improvement, increasing production from the baseline 264.2 STB/day to an optimized rate of 1100 STB/day at an injection rate of 1.0 MMscf/day. This represents a 76% production increase over natural flow. The system achieved stability with a design injection rate of 4.53 MMscf/day, producing 1369.58 STB/day, though economic considerations favored the lower injection rate. The continuous method provided steady, predictable flow characteristics suitable for stable production operations.

- **Intermittent gas lift** delivered dramatically superior performance for this specific well. The method achieved a production rate of 2827.76 STB/day with an exceptionally low gas injection requirement of only 0.026 MMscf/day. This represents a 90.7% increase over the natural flow baseline and a 61.1% improvement over continuous gas lift. The intermittent design operates at a cycle frequency of 6.76 cycles per hour with a slug volume of 17.41 STB and a fallback of 1492.44 feet, demonstrating efficient liquid accumulation and displacement mechanics.

The gas injection efficiency analysis reveals the most striking performance differential. Intermittent gas lift achieves superior production while consuming only 2.6% of the gas required by continuous injection (0.026 MMscf/day versus 1.0 MMscf/day). This 38-fold reduction in gas consumption while simultaneously delivering 2.6 times higher production represents exceptional resource utilization efficiency.

The fundamental reason for intermittent gas lift's superior performance in this well lies in the reservoir and well characteristics. With a productivity index of 2.01 STB/day/psi, the well exhibits relatively low deliverability, making it an ideal candidate for intermittent operation. The well requires time to accumulate fluid in the tubing before periodic high-pressure gas injection can efficiently displace accumulated liquid slugs to the surface. Continuous injection, while effective, cannot overcome the fundamental reservoir deliverability constraint as efficiently as the slug-based intermittent approach for this particular well.

This research addresses the identified gaps in existing literature by providing a comprehensive, simulation-based comparative analysis of both gas lift methods for a naturally flowing well before field implementation. The study demonstrates the practical application of PROSPER for systematic method selection and optimization, contributing validated methodology to the body of petroleum engineering knowledge.

The findings underscore the critical importance of well-specific evaluation rather than generic selection criteria. While industry guidelines suggest continuous gas lift for higher productivity wells and intermittent for lower productivity wells, this study quantitatively validates that recommendation for the specific case study well, providing the engineering evidence necessary to support operational decision-making with confidence.

5.2 LIMITATIONS

Despite the comprehensive nature of this study, several limitations must be acknowledged:

1. Simulation-Based Analysis Without Field Validation: The entire study was conducted using PROSPER simulation software without actual field implementation and validation. While PROSPER is an industry-standard tool with proven reliability, actual field performance may deviate from simulated predictions due to operational complexities, equipment performance variations, or unforeseen reservoir behavior that cannot be perfectly captured in simulation models.

2. Single Well Case Study: The research focused on one specific well with particular reservoir characteristics (PI = 2.01 STB/day/psi, permeability = 400 md, reservoir pressure = 4500 psia). The findings and recommendations are therefore specific to this well's conditions and cannot be generalized to other wells without a similar detailed analysis. Wells with different productivity indices, fluid properties, or completion configurations may yield different optimal gas lift method selections.
3. Limited Economic Analysis: While the study evaluated technical performance metrics (production rates, gas injection efficiency), it did not conduct comprehensive economic modeling, including detailed capital expenditure, operating costs, gas supply costs, oil price sensitivities, net present value calculations, or full lifecycle economic analysis. The recommendation for intermittent gas lift is based primarily on technical performance rather than complete economic optimization.
4. Static Reservoir Conditions: The simulation assumed constant reservoir properties throughout the analysis period. In reality, reservoir pressure continues to decline, water cut increases over time, and fluid properties change as the well matures. The study did not evaluate how the optimal gas lift method might change as these dynamic reservoir conditions evolve over the well's producing life.
5. Absence of Operational Risk Assessment: The study did not quantitatively assess operational risks associated with each gas lift method, including valve reliability, cycle control challenges, equipment failure probabilities, intervention requirements, or production interruption risks. These operational considerations can significantly impact method selection in field applications, particularly in remote or offshore locations where intervention costs are high.

5.3 RECOMMENDATIONS

Based on the simulation analysis and findings of this study, the following recommendations are made:

1. Intermittent gas lift should be implemented as the optimal artificial lift method for the case study well based on its superior performance: 2827.76 STB/day production with only 0.026 MMscf/day gas injection, representing 90.7% improvement over natural flow and 61.1% over continuous gas lift.
2. Install five gas lift valves at depths and specifications determined in the PROSPER design (Figure 4.7), with proper spacing, closing pressure, and injection pressure configurations.
3. Target operational parameters should be: gas injection rate of 0.026 MMscf/day, cycle frequency of 6.76 cycles/hour (approximately 8.9 minutes per cycle), and surface injection pressure as per valve design specifications.
4. Validate the PROSPER model against actual field performance data within the first three months of installation, comparing simulated versus measured production rates, pressures, cycle characteristics, and gas consumption to refine the model.
5. Conduct periodic performance reviews quarterly during the first year and semi-annually thereafter to re-optimize injection rates, cycle timing, and valve settings as reservoir pressure declines and water cut changes.
6. Develop contingency protocols whereby if intermittent gas lift performance falls below 2000 STB/day, immediate investigation should be conducted to identify causes (valve

malfunction, reservoir changes, completion issues) before considering alternative lift methods.

7. Maintain continuous gas lift as a backup option (1100 STB/day at 1.0 MMscf/day injection) if intermittent operation proves operationally challenging due to cycle control difficulties, surface facility limitations, or equipment reliability issues.
8. Adopt simulation-based evaluation methodology using PROSPER or equivalent tools for all future artificial lift selection decisions in the field, eliminating costly trial-and-error approaches and enabling data-driven decision-making.
9. Apply the intermittent gas lift evaluation framework to other wells in the field with a productivity index below 3 STB/day/psi, as this study demonstrates such wells are prime candidates for intermittent lift optimization.
10. Conduct follow-up research, including: (a) field validation studies comparing predictions with actual performance; (b) multi-well analysis to develop generalized selection criteria; (c) comprehensive economic modeling with NPV and IRR calculations; (d) dynamic reservoir simulation to evaluate long-term performance; and (e) environmental impact assessment of both gas lift methods.

This study demonstrates that systematic, simulation-based artificial lift evaluation using industry-standard tools like PROSPER enables confident, data-driven decision-making that maximizes production while minimizing costs and technical risks. For the specific well analyzed, intermittent gas lift emerges as the clear optimal choice, offering exceptional production enhancement with minimal resource consumption. The methodology established in this research provides a replicable framework for similar optimization studies across the petroleum industry, ultimately contributing to improved recovery from hydrocarbon reservoirs and enhanced economic performance of producing assets.

The transition from natural flow to artificial lift represents a critical decision point in a well's productive life. By employing rigorous simulation analysis before field implementation, operators can avoid costly mistakes, optimize resource allocation, and maximize the economic value extracted from their petroleum assets. This research affirms that the investment in proper engineering analysis yields substantial returns through improved production performance and operational efficiency.

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