

GAS LIFT OPTIMIZATION ACHIEVED AT SCALE THROUGH AUTOMATED MODEL BUILDING, AUTOMATIC MODEL TUNING, AND APPLICATION OF AUTONOMOUS CONTROL LOGIC THROUGH AN ENTERPRISE PRODUCTION OPTIMIZATION SOLUTION

Vineet Chawla, Marisely Urdaneta, and Cesar Verde
Weatherford

ABSTRACT

The efficient management of gas lift systems is pivotal in minimizing operational costs and maximizing production for a large majority of unconventional wells. By leveraging automated workflows to efficiently build and tune physics-based nodal analysis models, operators can optimize well performance and gas injection rates thus reducing operational expenses. A cornerstone of effective gas lift optimization is the seamless integration of real-time data with physics-based models. Automated assisted workflows streamline this process which enables continuous optimization of gas lift injection rates to compensate for changing production rates, gas liquid ratios, and reservoir pressures.

The author emphasizes the value of having an evergreen tuned well model to optimize every gas lifted well. Optimization can be realized in some cases by increasing or decreasing gas injection, as the model often shows over injection can reduce production. The challenges in realizing the value from a physics-based well model for every well include staff time to build and maintain the models, time to tune the models, and time to make gas injection rate adjustments. The gas lift optimization workflow presented requires significantly reduced engineering staff time by letting automated processes continuously complete the majority of the workflow.

INTRODUCTION

Gas lift is one of the most widely applied artificial lift methods in unconventional and mature oil fields due to its flexibility, relatively low surface complexity, and ability to accommodate declining reservoir pressure and increasing water-cut. In the Permian

Basin, gas lift has become the dominant lift method as operators transition away from higher-cost lift systems and seek scalable solutions for pad-based developments.

Despite its apparent simplicity, gas lift optimization is a dynamic and complex problem. The optimal gas injection rate for a given well changes continuously as reservoir pressure declines, fluid composition evolves, surface backpressure fluctuates, and wellbore configuration changes following workover activities. Manual optimization approaches struggle to keep pace with these changes, particularly when applied across hundreds of wells connected to shared compression infrastructure.

PERMIAN BASIN GAS LIFT OPERATING CHALLENGES

The Permian Basin presents a unique operating environment that amplifies the challenges associated with gas lift optimization. Rapid production declines, increasing water-cut, and widespread use of centralized compression systems require frequent adjustment of lift parameters to maintain stable flow and economic production. Wells are commonly grouped by pad or facility, meaning inefficient gas allocation to a single well can negatively impact overall field performance.

Operational constraints such as limited compressor capacity, gas buyback economics, and surface pressure limitations further complicate optimization efforts. These conditions make the Permian Basin an ideal candidate for automated, physics-based gas lift optimization workflows that can operate continuously at scale.

FUNDAMENTALS OF GAS LIFT OPTIMIZATION

Gas lift reduces flowing bottomhole pressure by injecting compressed gas to decrease the effective density of the produced fluid column. In conventional gas lift, gas is injected into the annulus and enters the production tubing through gas lift valves,

whereas in annular gas lift, gas is injected directly into the tubing and produced fluids flow to surface through the annulus. While increasing gas-injection initially improves production, the relationship between injection rate and production response is highly non-linear. Under-injection can result in unstable flow or liquid loading, whereas over-injection can reduce liquid production due to gas slippage, increased annular pressure, and unfavorable multiphase flow regimes.

Traditional optimization heuristics such as targeting critical velocity or fixed injection setpoints often fail to capture this behavior. Physics-based nodal analysis, which couples reservoir inflow performance with wellbore outflow behavior, provides the necessary framework to identify true optimal operating points. In this paper, we will discuss how to address this challenge at field scale.

AUTOMATED MODEL BUILDING

In order to efficiently build physics-based well models for hundreds of wells, a unique data loader was developed through a collaborative effort between various teams. This process merges wellbore, completion, and production data from multiple databases into a centralized staging table used to create the model. Any missing model data such as fluid gravities, reservoir pressures, and pipe roughness factors are manually entered by the engineer to complete the well model generation. This workflow dramatically reduced the time required by engineering staff to build well models. In addition to building the initial model, the data loader automatically updates the model with any changes made to a well following workover activities overcoming a key barrier to large-scale gas lift optimization where manual model construction involves collecting data from multiple systems, validating well configuration, and entering numerous parameters.

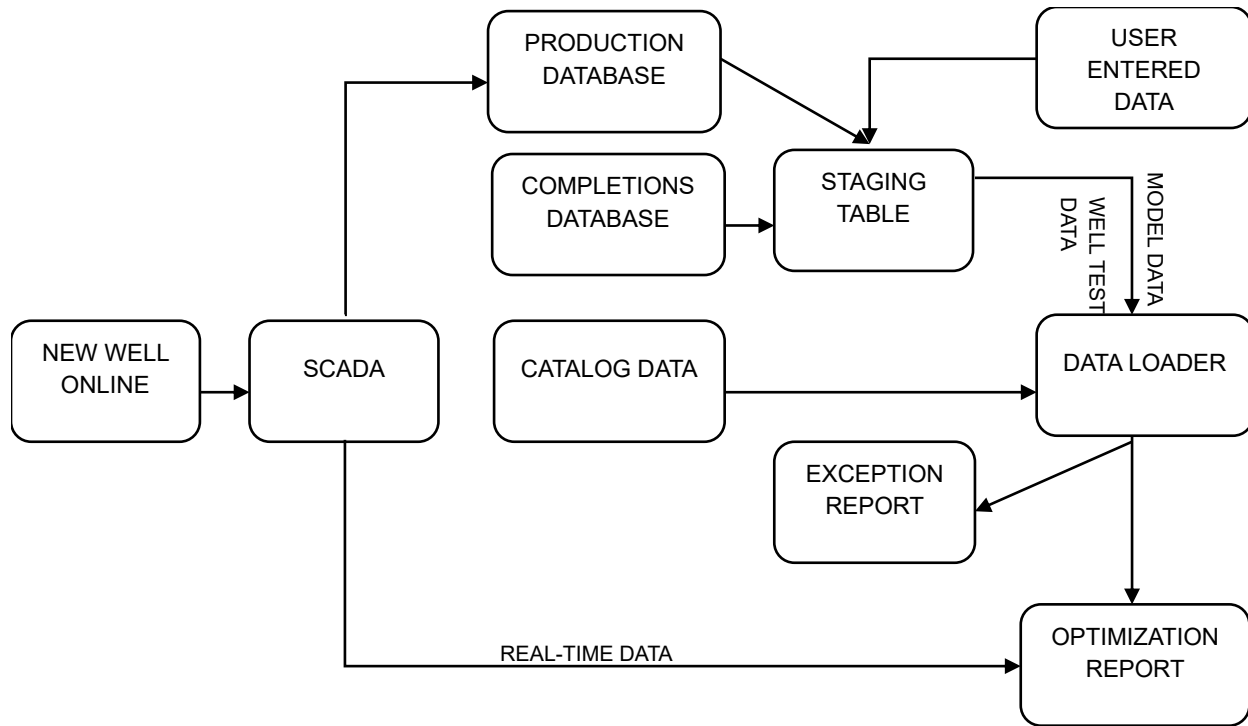


Figure 1 — Automated model building at scale integrating production, completion, catalog, and real-time SCADA data into an enterprise optimization workflow.

AUTOMATIC MODEL TUNING

To keep the model evergreen, the workflow automatically tunes the model using every well test. The Inflow performance relationship (IPR) and Vertical lift performance (VLP) variables are derived from the nodal well model, while Injection Rate, Tubing Head Pressure (THP), Casing Head Pressure (CHP), Water Cut (%) and GOR are extracted from production test data to construct an updated gas lift well performance curve. This performance curve facilitates the gas lift optimization process by ascertaining whether there is an under- or over-injection.

Additionally, model fidelity is critical to effective optimization. In figure 1, the workflow presented well models being automatically tuned using each available well test. Tuning focuses on matching observed production rates and, where available, flowing bottomhole pressures. This continuous tuning process produces evergreen models that

evolve alongside the well, ensuring optimization decisions are grounded in current operating behavior rather than historical assumptions.

PERFORMANCE CURVES AS THE OPTIMIZATION BACKBONE

Performance curves derived from continuously tuned nodal analysis models form the foundation of the automated gas lift optimization workflow. These curves describe the relationship between gas injection rate and resulting liquid production for a given well under current operating conditions. Unlike heuristic indicators or fixed injection targets, performance curves explicitly capture the non-linear response of the well to incremental changes in gas lift, including the transition between under-injection, optimal injection, and over-injection operating regimes.

Under-injection is characterized by insufficient gas lift energy to fully unload the wellbore, often resulting in unstable flow, liquid loading, or reduced drawdown efficiency. As gas injection increases, production typically improves until a maximum is reached. Beyond this point, additional injection can lead to diminishing returns or reduced liquid production due to gas slippage, increased flowing pressure losses, and unfavorable multiphase flow behavior. Performance curves make these regimes explicit and quantifiable, allowing optimization decisions to be based on physics rather than rules of thumb.

In the presented workflow, performance curves are regenerated (please refer to Figure 2) automatically using evergreen tuned well models, ensuring that optimization decisions reflect current reservoir conditions, fluid properties, surface pressures, and well configuration. Rather than optimizing absolute injection rates, the control logic evaluates Δ -injection—the production response associated with incremental increases or decreases in gas lift relative to current operating conditions. This approach allows the system to assess both upside potential and downside risk before recommending a change, while respecting operational constraints such as compressor capacity, minimum stability limits, and maximum allowable injection.

Performance curves also provide a consistent basis for comparing wells competing for limited lift gas within shared compression networks. By ranking wells based on marginal production response to gas injection, lift gas can be allocated to wells where it delivers the greatest incremental value, while over-injected wells are identified as candidates for gas reduction without sacrificing oil production. Wells operating outside expected curve behavior are flagged as exceptions, prompting further review for data quality issues, mechanical constraints, or changing reservoir conditions.

By anchoring optimization decisions to physics-based performance curves, the workflow enables repeatable, scalable gas lift optimization across large well populations. This approach reduces reliance on manual surveillance, improves decision consistency, and provides a transparent engineering rationale for both automated recommendations and human-in-the-loop intervention.

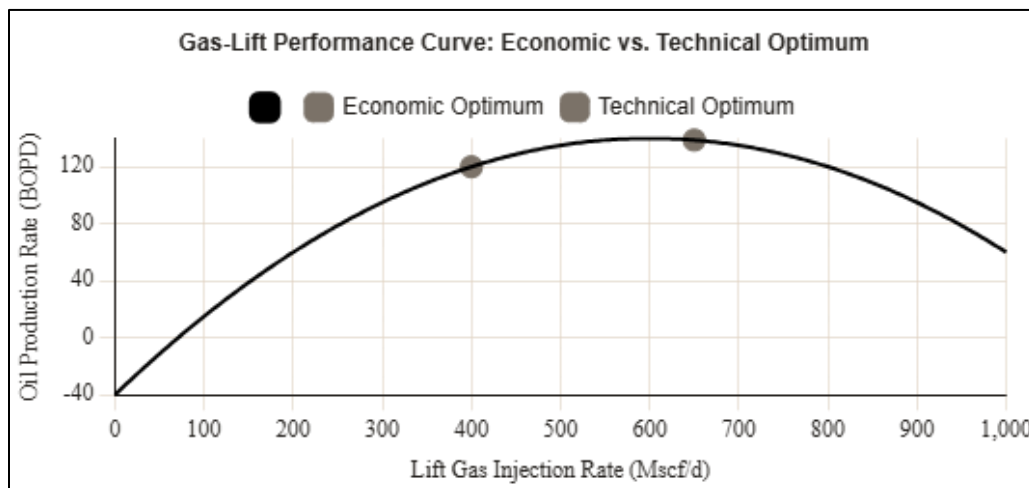


Figure 2 — Determination of Optimal Lift-Gas Injection Rates Using Performance Analysis.

AUTONOMOUS CONTROL LOGIC DESIGN PHILOSOPHY

Autonomous Control Logic (ACL) translates model-based insights into repeatable operational decisions. ACL, which was created through a collaborative effort of subject matter experts and computer programmers, was designed to use the tuned model's performance curve to determine optimum injection rates for each well. The ACL evaluates solutions at rates above and below current injection rates and solves for total fluid rates and oil production. Based on these results, and parameters set by the Operator within the ACL control interface, the system automatically suggests an optimum injection rate. The frequency of optimization runs can be easily defined by the Operator but is typically done anywhere from 4 hrs. to once a day. Safeguards are incorporated to prevent unstable operation and excessive adjustment frequency.

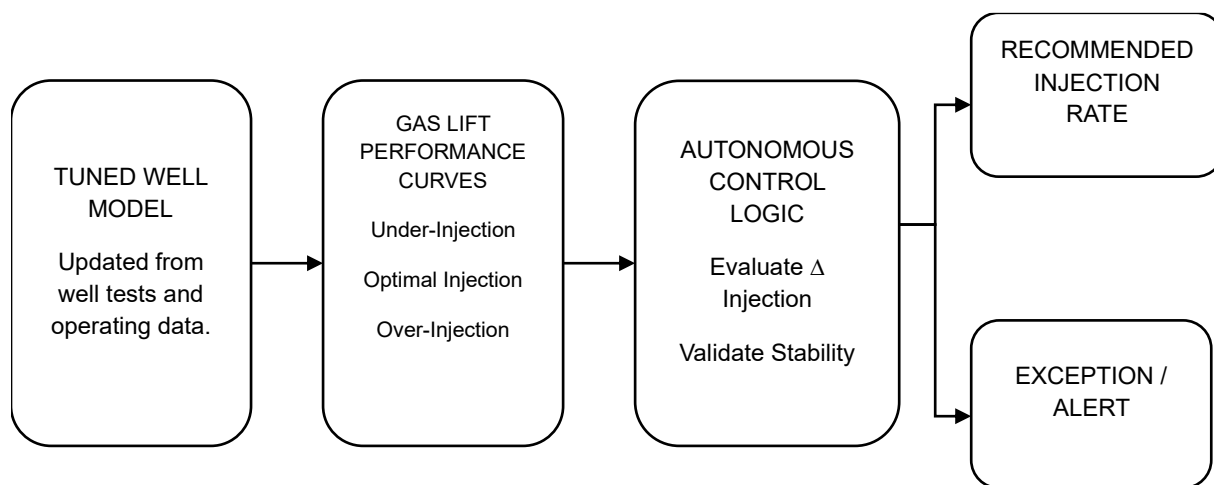


Figure 3 — Autonomous gas lift optimization workflow illustrating the use of tuned well models and gas lift performance curves to evaluate Δ injection and generate recommended actions or exception alerts.

NUMBERED CASE STUDIES FROM PERMIAN BASIN DEPLOYMENTS

Case Study 1: Over-Injection Identification and Gas Reduction.

A mature gas-lifted well exhibited stable oil production but with disproportionately high lift-gas usage. The ACL analyzed well's gas lift performance identifying that the well was operating in an over-injection regime, where additional injection gas no longer contributed to incremental liquid production. To optimize performance, it generated the optimal gas injection rate, and it was systematically reduced in three stages from 900 Mscf/d to 750 Mscf/d. This controlled reduction restored the well to an efficient operating point, increasing oil production from 126 BOPD to 130 BOPD while simultaneously lowering lift gas consumption. The optimization improved overall compression utilization and reduced unnecessary energy demand without

compromising production stability. This event was observed amongst other wells in the study, please see figure 4.

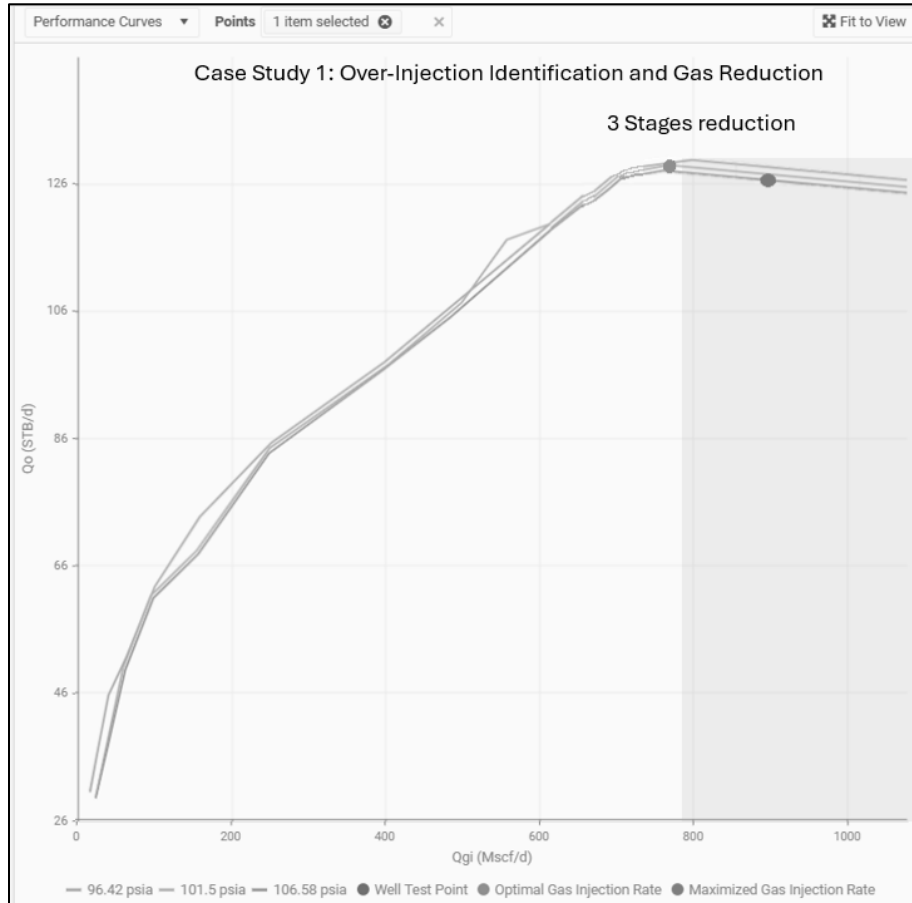


Figure 4 — Over-Injection identification and Gas Reduction.

Case Study 2: Incremental Production Through Optimized Injection.

In a second well, routine surveillance indicated that the gas lift system was supplying adequate injection to sustain production. However, evaluation using physics-based gas-lift performance curves identified additional production potential that was not evident from conventional monitoring alone. The analysis demonstrated that the well was operating below its optimal injection point, with clear opportunity for increased lift efficiency through incremental gas injection.

Based on the optimized operating point recommended by the Autonomous Control Logic (ACL), the gas injection rate was increased from 400 Mscf/d to 450 Mscf/d. This targeted adjustment resulted in a sustained increase in oil production from 274 BOPD to 284 BOPD. Similar behavior was observed in other wells included in the study, reinforcing the value of performance-curve-based diagnostics for identifying under-injection and unlocking incremental production, please refer to figure 5.

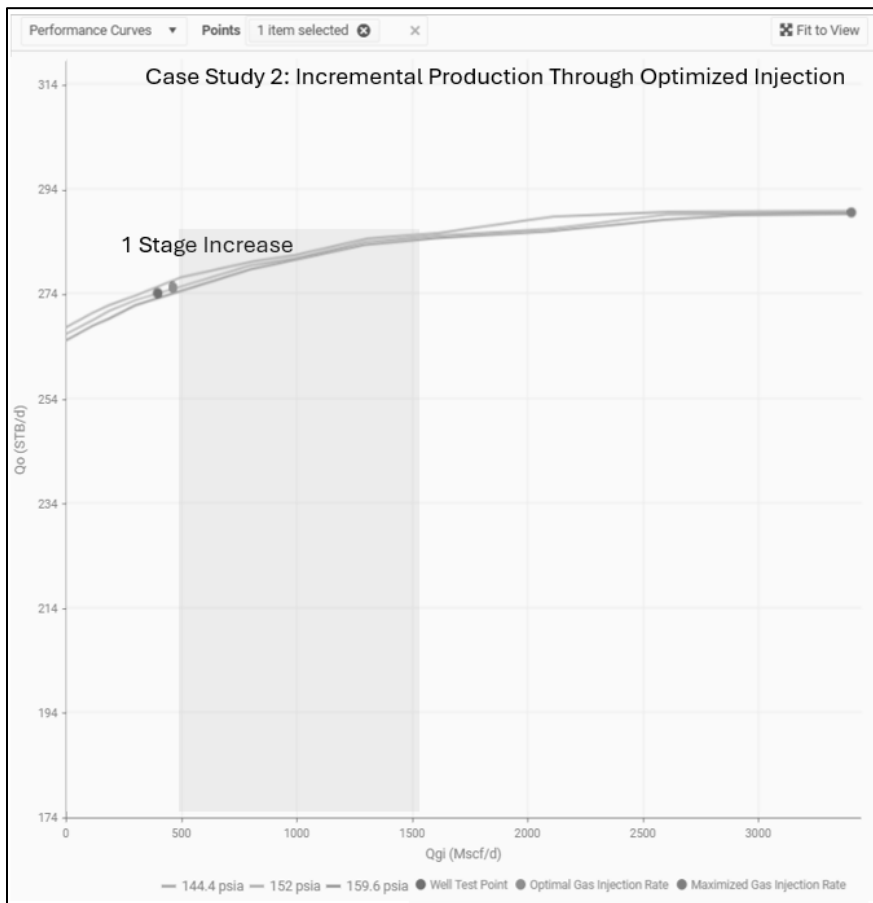


Figure 5 — Incremental Production Through Optimized Injection.

Case Study 3: Portfolio-Level Scalability and Engineering Efficiency.

The transition from single-well deployment to a portfolio-level implementation of the automated gas-lift optimization workflow provides a clear basis for evaluating both

scalability and incremental value creation. At the individual-well level, the Autonomous Control Logic (ACL) demonstrated the ability to identify inefficiencies and adjust injection rates in response to physics-based performance diagnostics. Extending the same workflow across a multi-well system tied to shared compression capacity exposed the controller to realistic field constraints namely, compression limits, cross-well interactions, and variable performance curves. This broader deployment allowed assessment not only of technical performance but also of the system's capacity to deliver consistent, repeatable optimization across an entire asset.

When implemented in 20 wells, the ACL delivered a 2% uplift in total oil production and a 6% reduction in gas-buyback volumes, even though, for a subset of seven wells, the optimization action was applied only once during the initial deployment. This contrasts with the behavior of manually tuned wells, where optimization typically requires repeated engineering intervention and tends to degrade as operating conditions drift from their modeled states. The fact that a single automated adjustment generated measurable performance improvement highlights the workflow's ability to apply higher-fidelity physics-based tuning compared with conventional engineering surveillance.

RESULTS

Long-term autonomous control further differentiated the automated approach. When the same seven-well subset operated in fully autonomous mode for six months, the ACL continued to adapt injection rates as conditions changed, resulting in a cumulative gain of approximately 4,500 STB and 327 MMSCF of gas savings. By contrast, a conventional workflow characterized by periodic surveillance, manual model updates, and engineer-triggered setpoint changes would not typically capture this level of sustained incremental value, especially under dynamic reservoir and facility constraints. The results therefore demonstrate tangible benefits associated with continuous closed-loop optimization rather than static or episodic adjustments.

An economic comparison further underscores the value proposition. Using standard assumptions of USD 65/bbl. oil price and USD 35/bbl. operating expense, incremental oil production from the autonomous deployment along with gas savings contributed to an economic impact of USD 790,000 over the evaluation period significantly exceeds what would be expected from traditional, engineer-driven tuning performed on a periodic basis.

Taken together, these results illustrate a clear differentiation between isolated, single-well optimization and scalable, portfolio-level deployment. While a one-time automated adjustment yields meaningful returns, persistent autonomous operation delivers step change improvements in both production and gas lift efficiency, particularly in systems constrained by shared compression. The comparison demonstrates that the ACL not only scales technically but also provides material incremental value compared with conventional workflows at both the well and asset levels.

LESSONS LEARNED AND BEST PRACTICES

Deployment of the autonomous gas-lift optimization workflow across multiple wells yielded several important technical and operational insights. Overall, results showed that preserving model fidelity was more critical than increasing model complexity. High-quality performance curves developed from rigorously tuned inflow and lift performance models consistently outperformed heuristic or rule-based indicators. Automation delivered the greatest value when configured within clearly defined operating envelopes and complemented by periodic engineering review to ensure alignment with evolving well conditions.

A key lesson from the field trial was the importance of a structured approach to sustaining model accuracy. Continuous calibration, supported by reliable and timely field data, allowed the Autonomous Control Logic (ACL) to adapt to changes in reservoir behavior and surface-facility conditions without requiring extensive manual intervention. Conversely, interruptions in data flow or incomplete representation of system dynamics reduced controller effectiveness and, in some cases, limited optimization opportunities.

These observations underscore the need for workflow standardization, robust data governance practices, and explicit integration of facility constraints to enable reliable and scalable automation across an asset.

The following considerations emerged as particularly influential to controller performance:

Liquid Loading

Liquid loading had a significant impact on well deliverability and gas lift efficiency. Incorporating explicit liquid loading diagnostics and mitigation logic into the ACL is essential to avoid misclassifying production declines such as injection inefficiencies.

System Dynamics

Adjustments to injected-gas rate directly affected flowing pressures and, in certain instances, produced unintended reductions in oil rate when injection was lowered. These interactions highlight the importance of system-level awareness within the control strategy, especially in fields with shared compression or wells sensitive to backpressure changes.

Pilot Valves

Pilot-operated valves were present in the field but were not explicitly accounted for in the current control logic. Because pilot valves influence valve opening behavior and unloading sequence, future ACL iterations should incorporate detection and modeling of these configurations to improve prediction accuracy and control stability.

CONCLUSIONS AND FUTURE DIRECTION

The field deployment of an automated, physics-based gas-lift optimization workflow demonstrated that autonomous control could deliver sustained and scalable production improvements across Permian Basin assets. The integration of continuously calibrated performance curves and system-aware control logic enabled reliable optimization under dynamic reservoir and facility conditions, while significantly reducing the need for manual engineering surveillance. Results from multi-well implementation confirm that physics-based automation provides a repeatable pathway for improving gas-lift efficiency, reducing operating costs, and enhancing overall asset productivity.

Looking ahead, further value can be realized by expanding automation beyond advisory mode. Future development will focus on full closed loop operation, enabling the Autonomous Control Logic (ACL) to continuously adjust gas-injection rates through automated control valves without human intervention. Additional enhancements including tighter coupling with surface-network optimization, improved representation of system constraints, and broader integration of well-test and facility data—will strengthen the robustness and responsiveness of the control framework. Collectively, these advancements are expected to unlock additional production potential and support large-scale, low-touch optimization across diverse operating environments.

REFERENCES

- **Brown, K. E.** *The Technology of Artificial Lift Methods, Volume 2a: Gas Lift*. PennWell Books, Tulsa, Oklahoma, 1984.
- **Beggs, H. D.** *Production Optimization Using Nodal Analysis*. OGCI Publications, Tulsa, Oklahoma, 1991.
- **Qin, Q.** "A Comprehensive Review of Gas Lift Optimization Methods." *Journal of Petroleum Science and Engineering*, 2024.
- **Abdelkerim, O., Leggett, S., Lu, J., and Nelle, W.** "High Pressure Gas Lift Optimization Using Nodal Analysis." *SPE-219533-MS*, SPE Artificial Lift Conference and Exhibition – Americas, The Woodlands, Texas, 2024.
- **Johnson, M.** "Annular Flow Gas Lift Options and Improvements." *Southwestern Petroleum Short Course Proceedings*, 2023.
- **Society of Petroleum Engineers (SPE).** "Fundamentals of Gas for Gas Lift Design." *PetroWiki / OnePetro*, 2025.
- **Pronk, B., Elmer, W., Harms, L., et al.** "Single Point High-Pressure Gas Lift Replaces ESP in a Permian Basin Pilot Test." *SPE-195180-MS*, 2019.

ACKNOWLEDGMENTS

The authors would like to acknowledge the contributions of the subject matter experts, SCADA administrators, field operators, IT specialists, and professional services engineers whose collaboration and domain knowledge were essential to the successful development and field deployment of the gas-lift optimization workflow described in this paper. Their expertise in operations, data integration, system configuration, and field execution played a critical role in enabling reliable model automation, continuous tuning, and practical application of autonomous control logic under real-world operating constraints. The authors also recognize the close cooperation between engineering, operations, and digital teams, which was fundamental to translating physics-based optimization concepts into scalable and sustainable field solutions.