EVALUATING HIGH-PRESSURE GAS LIFT STRATEGY IN DELAWARE BASIN WITH A NEW DYNAMIC ITERATIVE NODAL ANALYSIS WORKFLOW

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INTRODUCTION

Many Delaware Basin wells utilizing annular flow gas lift (injection down the tubing and flow up the annulus) are unable to achieve injection through their lowest gas lift valve until many months after initial production with standard injection gas pressures of around 1,200 psi. Even with the larger flow area, the higher early-time liquid rates characteristic of the basin create so much frictional and hydrostatic pressure loss in the flowing gradient that shallow injection and multi-pointing are all but guaranteed. Perhaps the largest concern associated with this dynamic is the production impact; all else equal, production rates will be lower when injection depth is shallower. An exciting and relatively recent technology has emerged to address this challenge: high-pressure gas lift. By increasing the available injection pressure at surface from ~1,200 psi to ~1,800 psi or higher, injection gas can be confidently delivered to the bottom station, leading to a lighter overall flowing gradient and higher production. Figure 1 shows an example comparison of gas lift performance curves at different injection depths early after initial tube-up. High-pressure gas lift (HPGL) has seen enthusiastic industry adoption since it emerged prominently in the mid-2010s, with more than 3,000 installations between 2015 and 2024 (Harms et al. 2024). Field results have shown that HPGL wells can achieve production rates and drawdown comparable to electrical submersible pumps (ESPs) (Pronk et al. 2019), especially when compared against smaller ESPs (McNeilly et al. 2024).

High-pressure annular gas lift (HPAGL) accelerates early-life production relative to low-pressure annular gas lift (LPAGL), but it comes at a cost: booster compressors must be installed, are generally rented, and must be eventually removed. While HPAGL certainly results in higher early-time production, its application is limited to the early life of the well when LPAGL would be unable to achieve injection through the bottom station. The use or non-use of HPAGL has no impact on the long-term artificial lift strategy of the well in the mid- and late-life production periods. Since the mid-to-late-life artificial lift strategy is independent of the early-time use of HPAGL, a well's terminal flowing bottomhole pressure, and therefore its estimated ultimate recovery (EUR), are not impacted by the early use of HPAGL. Early-time barrels produced with HPAGL are an acceleration, as opposed to a true production gain.

The central question is straightforward: does the time-value of the accelerated production justify the additional cost? An evaluation technique was needed to quantify the life-of-well production impact and associated economics of HPAGL relative to LPAGL for a given well or type curve. Direct comparison of offset wells operating under different lift strategies is a natural starting point, but perfect analogs rarely exist. Differences in geology, offset depletion, drilling quality, completion design, and operational practices can easily obscure the impacts that can be truly attributed to the artificial lift strategy. Reservoir simulation is an alternative, but it is time-intensive to build, tune, and maintain and is not typically performed for screening-level artificial lift decisions. A practical middle ground was needed between these two approaches: a tool that could isolate the production impact of a change in artificial lift strategy without requiring a full reservoir model.

This paper presents a new dynamic iterative nodal modeling workflow that was developed to address this need. It will discuss the first application of the workflow (an economic evaluation of HPAGL vs. LPAGL) and relay insights and learnings regarding the key variables that can lead HPAGL to be either value accretive or value destructive, and how these results were used to optimize one Operator's artificial lift portfolio strategy, resulting in meaningful cost savings.

BACKGROUND: HIGH PRESSURE GAS LIFT IN DELAWARE BASIN

Currently, the Operator in question largely utilizes centralized gas lift (CGL) networks to distribute injection gas from compressor stations to well pads. Since compression occurs at centralized stations, relatively minimal on-wellpad infrastructure is required to facilitate gas lift provided that the wells' gas lift designs do not call for injection pressures higher than the ~1,200 psi CGL system pressure. Figure 2 shows a simplified schematic of how the CGL system delivers gas to the wells.

When LPAGL is selected as the artificial lift method, injection gas is directly routed from the CGL system to the well's production tree where it is injected down the tubing. There are several downhole configurations that can be utilized for LPAGL wells:

- Side-pocket mandrels (SPMs) with exhaust-to-casing (EC) configuration and retrievable injection-pressure-operated (IPO) valves
- Fluid mandrels with conventional IPO valves (provide full tubing access by maintaining drift ID)
- Internally mounted mandrels with conventional IPO valves (obstruct tubing access to all depths below the top station)

In all these configurations, live IPO valves are installed during initial tube-up at all unloading stations, and a screened orifice is generally installed in the bottom station. Port sizes for IPOs can vary, but 16/64" to 20/64" ports are common. The orifice generally has a larger port (20/64" to 26/64") to facilitate passage of the high injection rates typical of annular gas lift and prevent shallower IPOs from opening after injection reaches the orifice. The tubing is generally isolated from the annulus with a plug below the bottom station, to prevent gas heading around the end of tubing.

When HPAGL is selected as the artificial lift method, a 'booster' compressor must be installed at the well pad between the CGL system tie-in point and the well. Each booster compressor typically services a single well and increases available injection pressure from the ~1,200 psi available CGL system pressure to ~1,800 psi or higher. The installation of the booster requires additional utility infrastructure (electrical power or fuel gas systems) along with an expanded tangible and intangible construction work scope.

Downhole, HPAGL wells are usually configured with EC SPMs. Dummy valves are installed in all unloading stations during initial tube-up, and a screened orifice (24/64" to 26/64" port) is installed in the bottom station. The use of dummy valves and EC SPMs minimizes the downhole scope of HPAGL to LPAGL conversions; wells can be converted to LPAGL with a simple slickline operation where dummy valves are replaced with live IPO valves. This allows engineers to convert wells in a cost-efficient manner without a workover rig.

The Operator in question uses an optimization system to automatically allocate injection gas to the wells on each CGL network to maximize oil production at the network level. This system bases decisions on total available injection gas, and on gas lift performance curves for each well (Asgharzadeh Shishavan et al. 2022). Engineers enter minimum and maximum injection rates for each well based on that individual well's flow characteristics. Optimization ranges for HPAGL wells are typically narrower than their LPAGL counterparts; each well must maintain injection in a way that prevents operational issues with the booster compressor due to the one-well-one-booster configuration.

DYNAMIC ITERATIVE NODAL MODELING WORKFLOW OVERVIEW

Prior to the new modeling workflow and economic evaluation that are the subject of this paper, the decision to install HPAGL or LPAGL on a particular well was based on the oil EUR of that well's type curve. The rationale behind this approach is that wells with higher EURs generally have higher initial production rates, meaning those wells experience greater early time frictional impacts and have relatively shallower injection with LPAGL. Since the benefit of HPAGL comes from its ability to inject in the bottom station, it is a logical assumption that the wells that stand to benefit more from HPAGL are the wells that would have relatively shallower injection with LPAGL. The new modeling workflow focused on the wells that met the oil EUR threshold for HPAGL installation.

The first phase of the workflow is to establish the expected daily production profile of the HPAGL case, which can be a type curve or operational forecast of daily oil, water, and gas production. Expected flowing bottomhole pressure (FBHP) is calculated for each day of the HPAGL forecast assuming orifice injection using gradient calculations performed in commercially available nodal analysis software. Reservoir pressure is calculated for each day of the forecast using an internally developed correlation based on cumulative production and EUR. The combination of a reservoir pressure profile and an FBHP profile allows the well's inflow performance relationship (IPR) to be calculated for each day of the HPAGL forecast. Since cumulative production on each day is also calculated, the IPR is known at each point in cumulative production.

The next step in the workflow is to calculate the production profile for the LPAGL case. For each day, the workflow first looks up the appropriate IPR from the HPAGL case based on the LPAGL case's cumulative production. The bedrock assumption is that, all else equal, the LPAGL case and the HPAGL case will have the same IPR at any given point in cumulative production. Then, the workflow calculates what the injection depth and production rate would be with LPAGL using commercially available nodal analysis software, accounting for the lower available injection pressure with LPAGL. Successive gradient and system calculations are iteratively performed until the calculated LPAGL injection depth and production rate no longer change between iterations. The final calculated production rate for that day of the LPAGL case is appended to the LPAGL cumulative production profile, setting up the workflow for the next day of the LPAGL profile calculation.

The LPAGL modeling workflow is performed up to the point in cumulative production where the well is deemed ready for conversion to tubing-flow gas lift. This is based on the cumulative production of the HPAGL profile (type curve) at which the HPAGL liquid rate falls below a liquid rate trigger where wells are commonly deemed ready for conversion. After the LPAGL case surpasses this point in cumulative production, the profile reverts to the type curve starting at that point in cumulative production. The final generated LPAGL profile is piecewise and composed of two segments:

- the modeled production period up to the conversion cumulative production
- type curve starting from that point in cumulative production, out at least 10 years

Figure 3 outlines the steps of the modeling workflow.

As expected, the HPAGL production profile starts out higher than the LPAGL profile due to shallower injection with LPAGL. After an amount of time that is different in each scenario, the HPAGL case reaches a point where the maximum amount of production acceleration has occurred. At this point in time, the LPAGL case, having a more productive IPR due to less cumulative production, begins ‘catching up’ to the HPAGL case. The HPAGL and LPAGL production profiles, along with the associated costs of each method, are compared against each other in an economic model. The economic model calculates a range of metrics by which the two options can be compared, including incremental net present value (NPV), free cash flow, and payout.

HIGH PRESSURE GAS LIFT CASE STUDY RESULTS

The new modeling workflow was first applied in early 2025 to assess the economic viability of HPAGL for two Delaware Basin wells, one in Lea County, New Mexico, and one in Loving County, Texas. The wells had very similar oil EURs with only about a 5% deviation, and both EURs were well above the previous trigger point used to select HPAGL candidates. The New Mexico well had a significantly higher initial gas-oil ratio (GOR) than the Texas well (~1,600 scf / bbl vs. ~800 scf / bbl) and a lower water cut (~60% vs. ~75%), leading to a higher gas-liquid ratio (GLR). The New Mexico well also had a higher initial reservoir pressure, which equates to a lower productivity index (PI) than the Texas well (similar production with a higher reservoir pressure = lower PI). Figure 4 shows the production, GOR, PI, and water cut (WC) trends for the subject wells’ type curves.

Despite having almost identical oil EURs and oil production forecasts, the modeling workflow showed that HPAGL could accelerate more than four times more production on the Texas well than it could for the New Mexico well; roughly 40 thousand stock tank barrels of oil (MSTBO) acceleration compared with less than 10 MSTBO. This led to a profound difference in economic viability of HPAGL between the two wells as measured by 10-year NPV; HPAGL resulted in an NPV that was lower than the LPAGL NPV for the New Mexico well, whereas HPAGL led to an NPV that was higher than the LPAGL NPV for the Texas well. The magnitude of the incremental NPV varies by scenario, but incremental NPVs in the low six-figures per well were common. When the economic results were sensitized, it was found that there were no reasonable adjustments to controllable input variables that would lead to HPAGL being value accretive for the New Mexico well, whereas there were no reasonable adjustments to controllable input variables that would lead to HPAGL being value destructive for the Texas well. The factors that did materially move the economic needle were found to be mostly uncontrollable:

- GLR (determined by GOR and WC): more FBHP drawdown can be achieved from deeper injection when the fluid column is heavier (lower GLR).
- PI: more barrels are accelerated for each additional psi of drawdown when the PI is higher.

The lower GLR and higher PI of the Texas well combined to accelerate significantly more barrels with HPAGL than could be accelerated from the New Mexico well, despite the wells having similar oil EURs. Figure 5 shows the production acceleration with HPAGL of both the New Mexico and Texas wells. Figure 6 shows how changes to the input variable assumptions impact the calculated incremental NPVs, as determined through an economic sensitivity analysis.

For the New Mexico well where HPAGL was found to be value destructive in the base case, two additional scenarios were considered in economics:

1. An ‘early conversion’ scenario was created to model cases where HPAGL was originally installed but removed early. For example, NPV was calculated assuming the booster was removed after six months instead of in month 15 when the HPAGL case reached the liquid rate trigger signifying readiness for conversion to CGL.
2. An ‘interference’ scenario was assessed to see if HPAGL could be economically viable in scenarios where impending interference events (e.g., offset frac impacts) were likely to result in a loss or near loss of the well.

All credible HPAGL-with-early-conversion cases were found to be value destructive for the New Mexico well. The production impact at the time of early conversion was more significant than just comparing production between the base HPAGL and LPAGL cases directly at that time; since the HPAGL case has a higher cumulative production than the LPAGL case at the time of early conversion, it has a less productive IPR. This means that production right after early conversion drops below the LPAGL base case at that time.

The interference scenario assumed that production was ceased in all cases after the interference event. In the base case with no interference, accelerated barrels are eventually 'repaid' as the LPAGL case catches up. However, when an interference event terminates production before the LPAGL case can catch up, the accelerated barrels represent a permanent gain. In these types of scenarios, HPAGL can occasionally be economically justified for wells where it would otherwise be value destructive.

CONCLUSIONS & THOUGHTS ON BROADER APPLICABILITY

After the initial evaluation in early 2025, outputs from the workflow were used to evaluate the type curves of 36 additional new 2025 wells that had initially been identified as HPAGL candidates. New well type curves were compared against those of the New Mexico and Texas wells from the initial evaluation based on GOR, WC, and PI. The workflow was executed as needed for type curves with metrics in between those of the wells in the initial evaluation (e.g., a 1,200 scf / bbl GOR is between the 800 scf / bbl and 1,600 scf / bbl GORs from the initial evaluation and would require an additional execution of the workflow). This led to a meaningful optimization of HPAGL strategy across Delaware Basin; the New Mexico type curve from the initial evaluation proved to be more representative for a larger portion of the wellset in both New Mexico and Texas. Of the 36 wells that were evaluated, HPAGL was removed from scope for 31 of them. For the remaining five wells, HPAGL was affirmed as a value accretive lift strategy and pursued. This resulted in seven-figure savings of both capital and operating costs that would otherwise have been incurred with HPAGL between 2025 and 2026, along with significant NPV preservation.

The 2025 economic evaluation of HPAGL vs. LPAGL showed that HPAGL can still add value on the right candidate well, but that candidate selection should be more nuanced than the initial screening criteria that considered only oil EUR. While higher-rate wells generally have more friction and therefore relatively shallower injection with LPAGL (all else equal), HPAGL delivers the most value when wells have heavy flowing gradients (low GLR) and high productivity. For most Delaware Basin wells that were evaluated, the time-value of the production acceleration with HPAGL did not justify the additional cost from an NPV standpoint. HPAGL was, however, found to be value accretive for a subset of the wells. It is worth noting that this evaluation and its application to future development in the Delaware Basin are based on one Operator's system design and cost structure. While this system design and cost structure are reasonably representative of the broader gas lift landscape across the Delaware Basin, there may be other designs or cost structures that facilitate lower costs with HPAGL. The subset of wells where HPAGL is value accretive grows as overall cost shrinks.

While the workflow was developed initially to assess the economic viability of HPAGL, several other use cases have emerged. So far, it has also been successfully utilized to assess early-time production impacts after initial tube-up associated with different annulus sizes for different formations and type curves. It has also been used to assess the potential production acceleration associated with surface-controlled gas lift, a relatively new technology that uses electrically or hydraulically controlled gas lift valves to enable a gas lift well to operate at a higher surface injection pressure by eliminating the pressure losses characteristic of IPO designs. Other use cases will no doubt emerge as additional technologies and lift strategies are identified and considered.

REFERENCES

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FIGURES

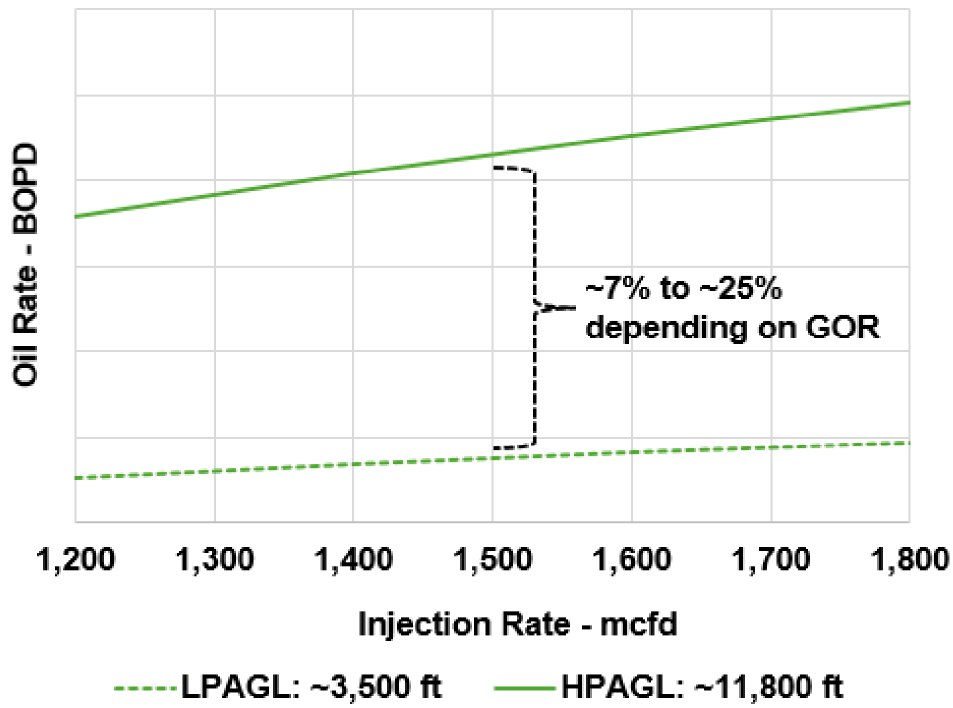

Figure 1 – Example of HPAGL vs. LPAGL gas lift performance curves early after tube-up

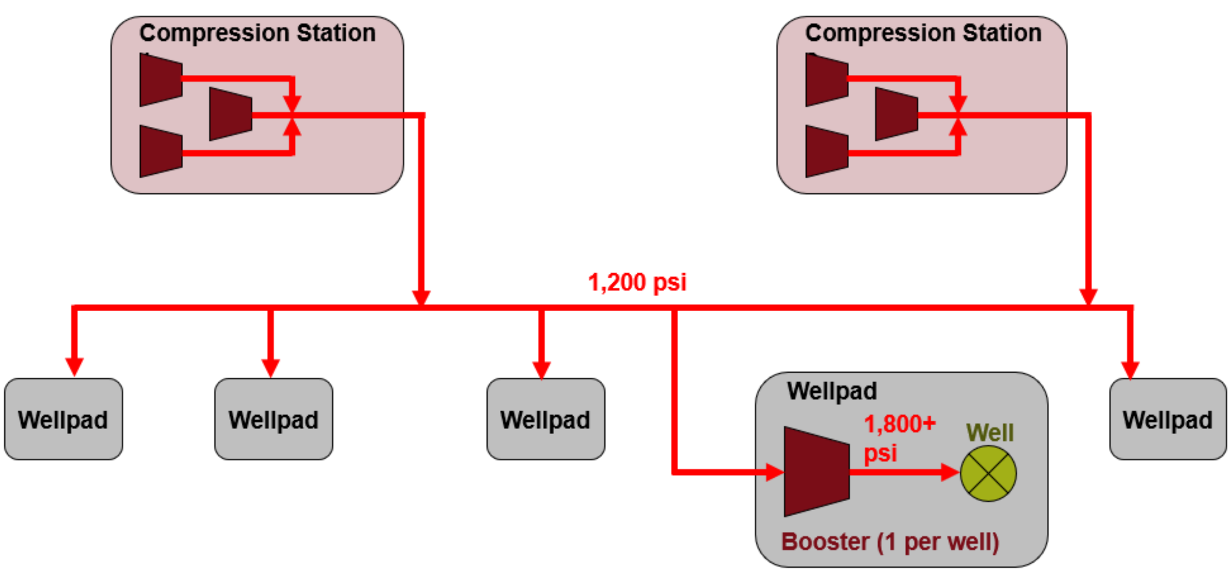

Figure 2 – Simplified centralized gas lift system schematic

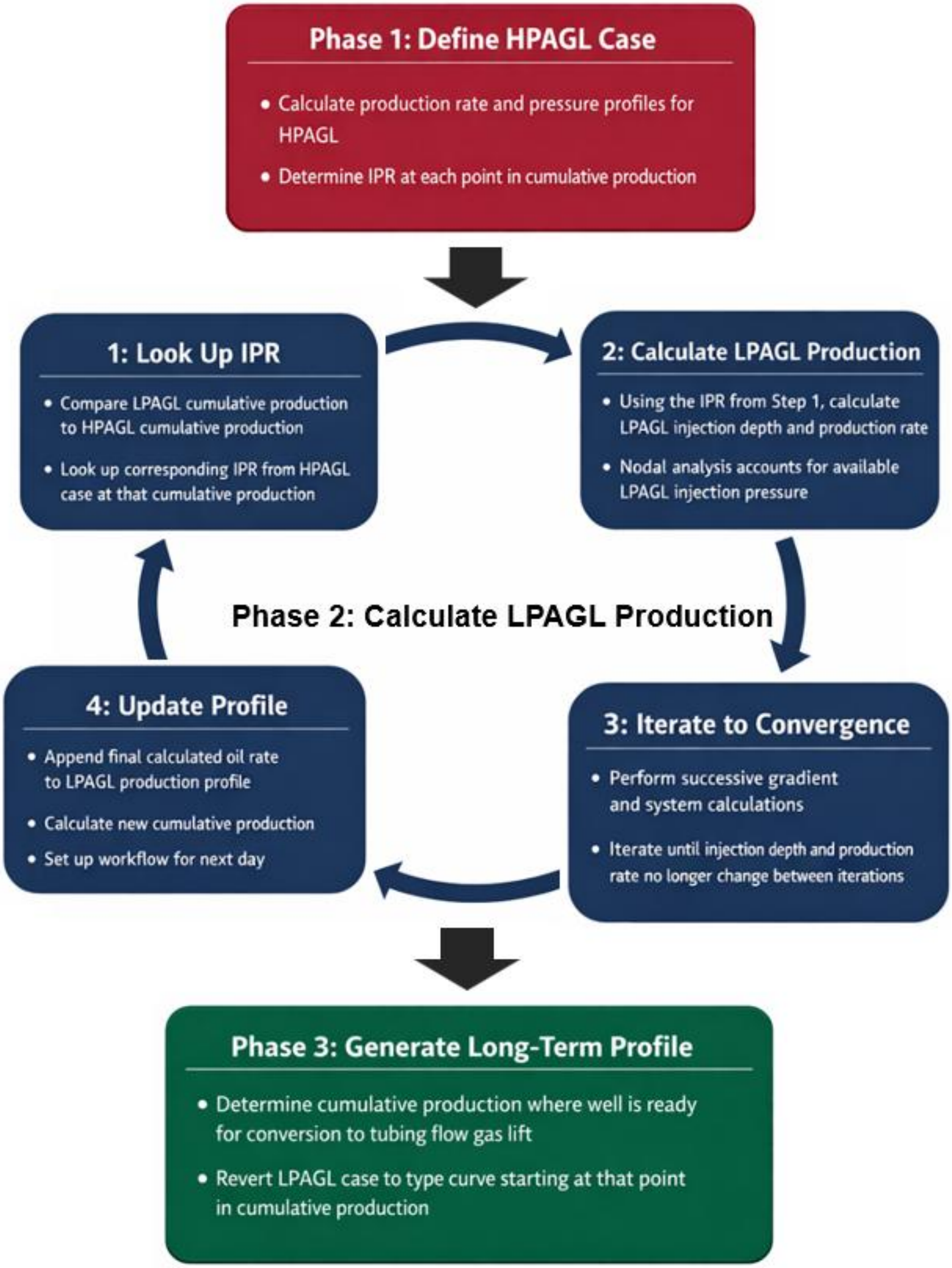

Figure 3 – Iterative nodal modeling workflow overview

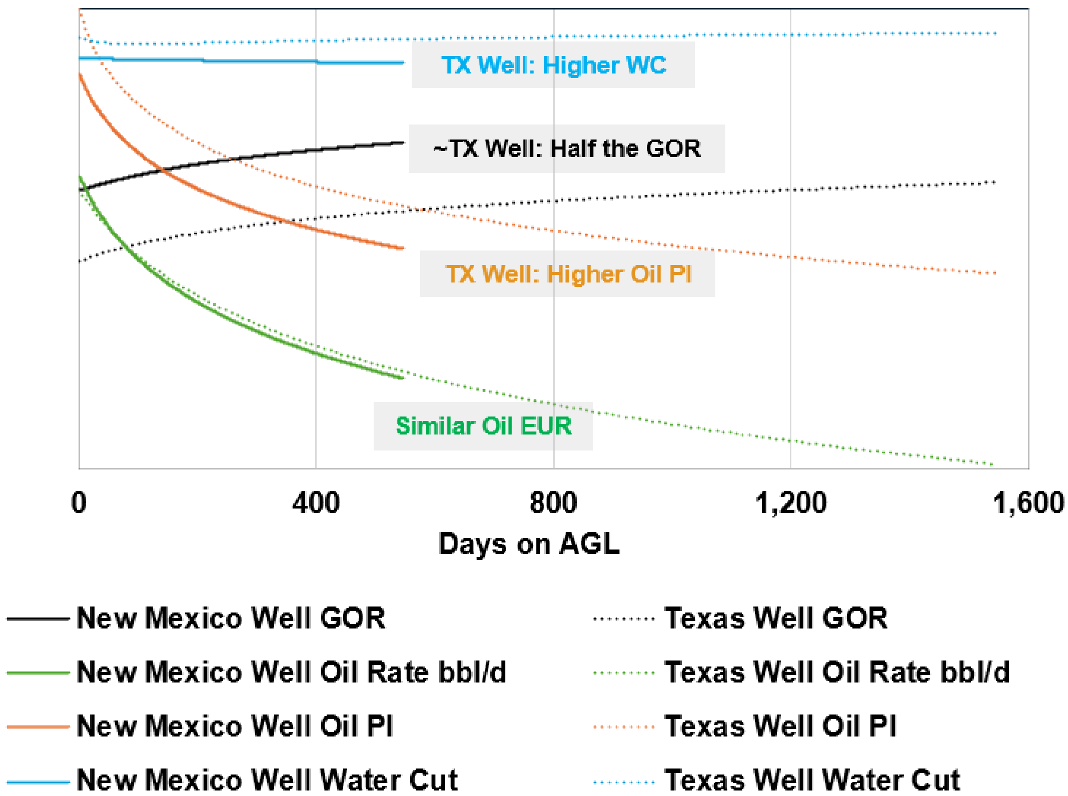

Figure 4 – Oil rate, GOR, PI, WC of Texas and New Mexico wells (economic eval)

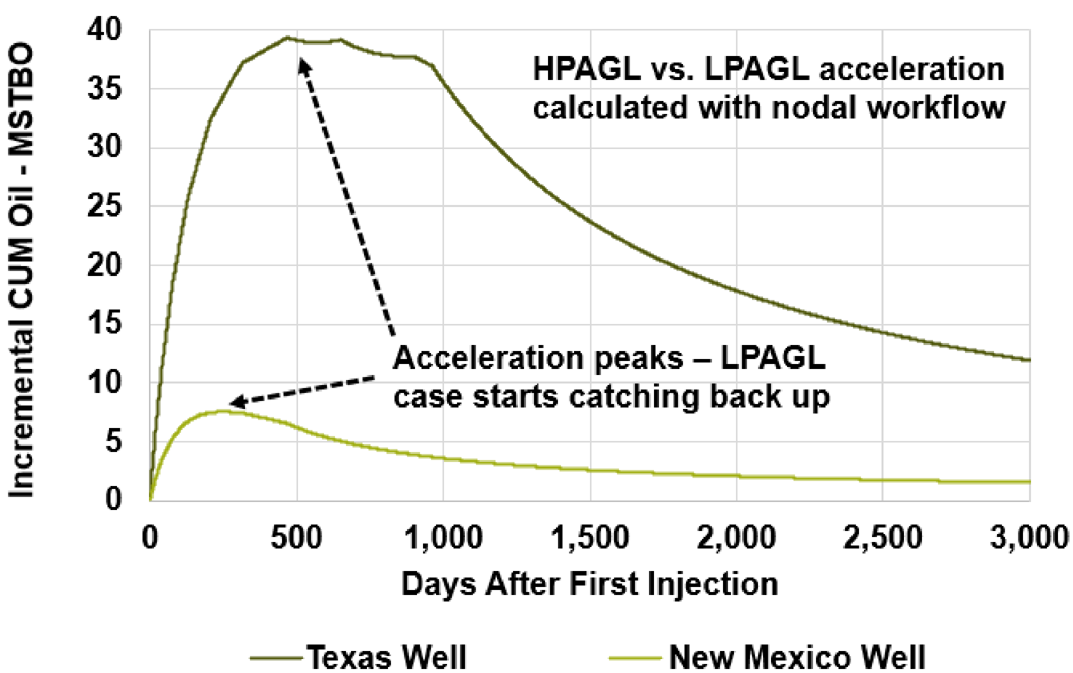

Figure 5 – Production acceleration with HPAGL vs. LPAGL

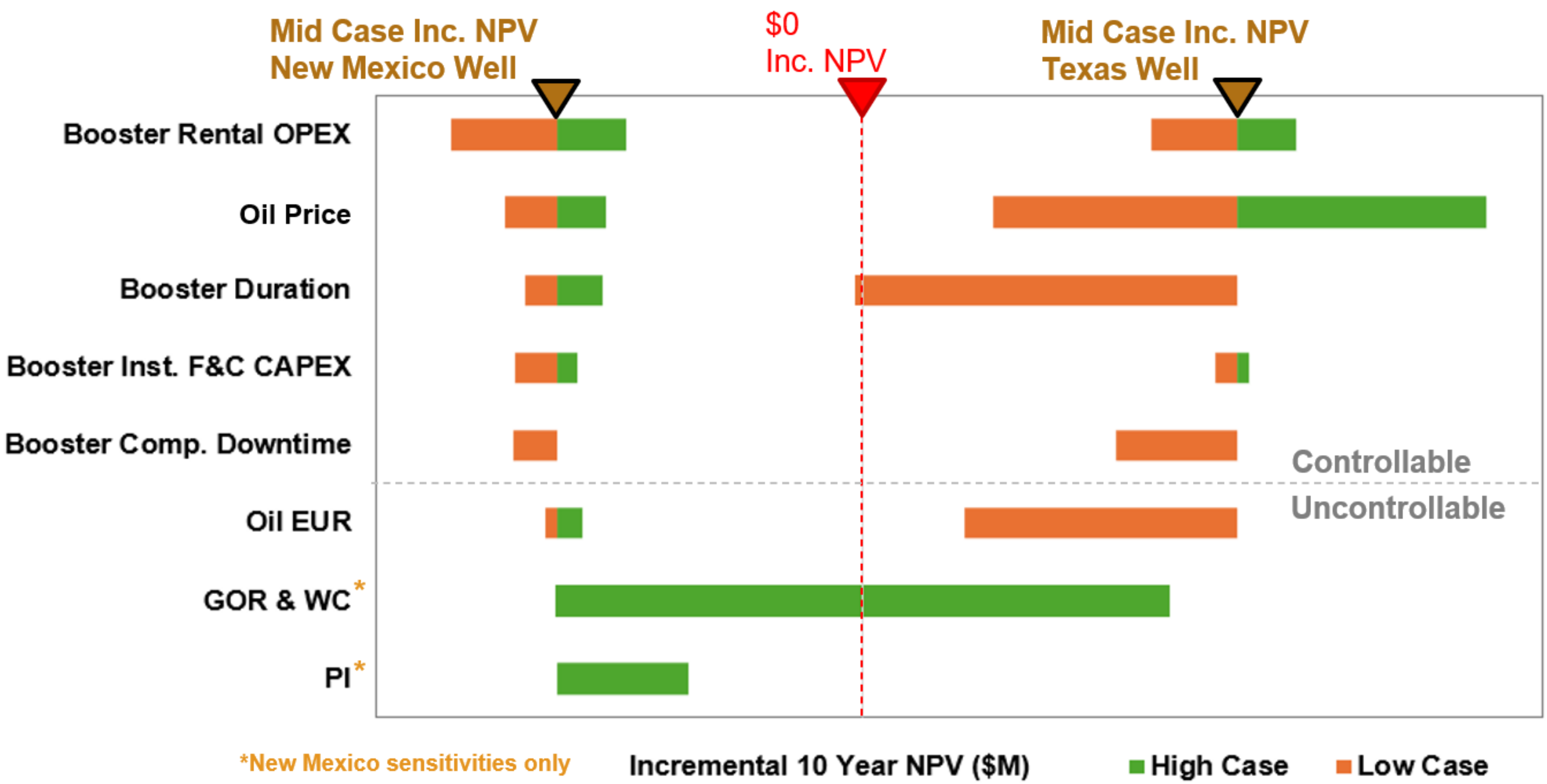

Figure 6 – Economic results: incremental NPV of HPAGL vs. LPAGL (positive inc. NPV = HPAGL is better)