



INTEGRATED PRODUCTION-SYSTEM OPTIMIZATION FOR LATE-LIFE GAS-CONDENSATE FIELDS: COUPLING WELL DELIQUIFICATION, NEAR-WELLBORE REMEDIATION AND LOW- PRESSURE SURFACE OPERATION

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Abstract. Mature gas-condensate fields commonly reach a stage at which production is no longer controlled by a single reservoir limitation. Declining reservoir pressure, retrograde condensate accumulation, positive near-wellbore skin, wellbore liquid loading, rising gathering-system backpressure, and insufficient compression capacity interact and can move a well from stable production to intermittent or fully loaded operation. This paper develops an integrated engineering workflow for screening late-life production options by coupling reservoir inflow, near-wellbore impairment, continuous liquid-removal criteria, tubing hydraulics, surface backpressure, and low-pressure compression. Five operating scenarios were compared: the existing system, surface compression only, velocity string combined with compression, selective near-wellbore remediation combined with compression, and a fully integrated bundle including gathering-system pressure reduction. The representative calculations increased stable gas rate from 42 to 76 thousand Sm³/d and raised the continuous-liquid-removal margin q_g/q_{crit} from 0.78 to 1.67, while the required wellhead pressure was reduced from 3.2 to 1.35 MPa. The results show that compression or stimulation applied independently may recover only part of the available deliverability; the largest and most stable benefit occurs when reservoir, wellbore, and surface constraints are treated as a coupled system. A screening



matrix is proposed for selecting interventions according to skin, liquid-loading margin, water/condensate influx, tubing friction, and compression availability. The workflow is intended for engineering diagnosis and option ranking before detailed compositional reservoir simulation, multiphase well modeling, and facility design.

Keywords: *gas-condensate field; late-life production; liquid loading; condensate banking; velocity string; wellhead compression; nodal analysis; near-wellbore remediation; surface backpressure; production optimization.*

1. INTRODUCTION

Gas-condensate reservoirs exhibit a production behavior that differs from both dry-gas and conventional oil reservoirs. Above the dew-point pressure, the hydrocarbon system may remain predominantly single phase in the reservoir. As depletion proceeds and pressure falls below the dew point, heavier components condense in the porous medium. Because the largest pressure gradient is usually concentrated close to a producing well, retrograde condensate often appears first and accumulates most strongly in the near-wellbore region. The resulting reduction in gas relative permeability is commonly described as condensate banking and can substantially impair well deliverability. The effect is especially important in low-permeability or heterogeneous reservoirs, where a relatively small zone of reduced effective gas permeability can consume a large share of the available pressure drawdown.

At the same time, a mature gas-condensate well is exposed to a second family of constraints inside the production string. Lower reservoir pressure decreases gas rate and superficial gas velocity. Water entering from an aquifer, completion interval, or behind-pipe channel and condensate produced from the reservoir can therefore accumulate in the tubing. Turner, Hubbard, and Dukler established the classical critical-velocity framework for continuous liquid removal, and later studies refined the criterion for low-pressure and complex well conditions [1,2,4,5]. Once the actual gas rate falls below the liquid-unloading threshold, the hydrostatic head of the accumulated liquid increases bottomhole pressure, which further suppresses inflow.



This feedback can cause severe rate cycling, heading, unstable choke behavior, and eventual well loading.

A third limitation is created by the surface production system. Gathering-line pressure, separator pressure, dehydration and treatment pressure requirements, and compressor suction pressure determine how much of the reservoir drawdown is actually available to move fluids through the well and surface network. In late field life, the surface backpressure that was acceptable at high reservoir pressure may become a dominant fraction of the remaining pressure potential. Lowering the receiving pressure by wellhead or centralized compression can therefore restore rate, but it can also increase liquid production, accelerate condensate dropout near the wellbore, increase erosional or hydrate risk, and shift the bottleneck to tubing or treatment equipment. For this reason, compression should be evaluated together with well deliverability and fluid-lifting behavior rather than as an isolated facility project [3–5,12].

The interaction of these mechanisms explains why single-action interventions frequently underperform. A velocity string can raise gas velocity but may impose excessive friction if its internal diameter is too small. Compression can lower wellhead pressure but may not revive a well with severe near-wellbore damage. Acid stimulation can reduce skin in a carbonate reservoir, but the additional inflow may remain unstable if accumulated liquid cannot be continuously lifted. Water shut-off can reduce hydrostatic loading but may not address condensate banking or high network backpressure. The engineering challenge is therefore to identify the active constraint set and choose a technically compatible intervention bundle.

Recent studies from Uzbekistan have emphasized the role of geological structure, acid–rock reaction, and thermobaric conditions in the behavior of carbonate near-wellbore zones. Samatov and Mahmudov modeled acid placement and permeability enhancement while explicitly accounting for near-wellbore geological and hydrodynamic conditions [16]. Meyliev, Samatov, and Boykobilova



discussed physicochemical transformations in different reservoir types, including low-pressure gas-condensate systems [17]. Ermatov, Samatov, and Hayitov investigated approaches to improve acidizing efficiency in carbonate reservoirs [18], while Akhatova, Samatov, and Jo'rayeva linked acidizing design to geological architecture and skin reduction [19]. A separate late-life gas-condensate study by Samatov and coauthors discussed workover, water isolation, and stimulation as tools for extending the operation of small-reserve fields [20]. These publications provide a useful local foundation, but an integrated link between near-wellbore remediation, liquid unloading, and low-pressure surface operation remains a practical need.

The objective of this study is to develop and demonstrate an integrated screening workflow for late-life gas-condensate production systems. The specific aims are: (i) to connect condensate-bank and skin effects with well inflow; (ii) to include continuous-liquid-removal margin as an explicit operability constraint; (iii) to quantify the effect of reducing wellhead and separator pressure; (iv) to compare single and combined intervention scenarios; and (v) to define a decision matrix that can be used before detailed field-specific simulation. The work does not claim to replace compositional reservoir simulation, calibrated multiphase well models, or compressor vendor design. Instead, it provides a transparent engineering bridge between diagnosis and high-fidelity modeling.

2. MATERIALS AND METHODS

2.1. Integrated production-system concept

The proposed methodology treats the reservoir, near-wellbore region, completion, tubing, gathering system, separator, and compression unit as one pressure-connected production chain. Figure 1 summarizes the workflow. The first diagnostic step identifies the dominant source of lost deliverability: reservoir depletion, near-wellbore impairment, liquid loading, tubing friction, surface backpressure, or a combination of these. Candidate interventions are then screened against the constraints that they remove and the new constraints that they may introduce.

The method is deliberately modular. Reservoir inflow is represented through real-gas pseudopressure and a skin/non-Darcy term. The liquid-loading module compares actual gas flow with a critical removal rate. The wellbore module accounts for hydrostatic, frictional, and acceleration losses. The surface module represents separator and gathering backpressure, while the compression module evaluates suction pressure, compression ratio, and specific energy. A stable operating point must satisfy all modules simultaneously.

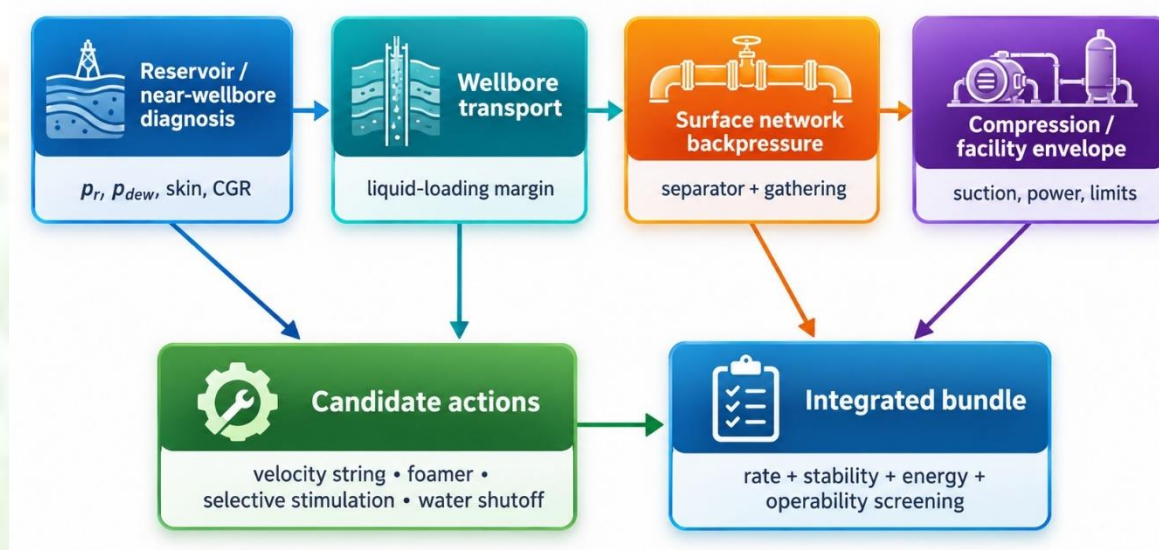


Figure 1. Integrated workflow for diagnosing and screening late-life gas-condensate production constraints.

2.2. Reservoir inflow and near-wellbore impairment

For gas and gas-condensate inflow, pressure-squared approximations become less reliable when gas viscosity and compressibility factor vary strongly with pressure. A more general representation uses real-gas pseudopressure. The pseudopressure function is written as:

$$m(p) = 2 \int_0^p \frac{p}{\mu_g(p)Z(p)} dp \quad (1)$$

where p is pressure, μ_g is gas viscosity, and Z is the gas compressibility factor. For radial flow, the stable gas rate can be represented in proportional form as:

$$q_g \propto \frac{kh [m(p_r) - m(p_{wf})]}{\ln(r_e/r_w) + S + Dq_g} \quad (2)$$

where k is effective permeability to gas, h is net pay, p_r is average reservoir pressure, p_{wf} is flowing bottomhole pressure, r_e and r_w are drainage and wellbore radii, S is skin, and Dq_g represents rate-dependent non-Darcy resistance. In a gas-condensate reservoir, the effective gas permeability inside the condensate bank may be much smaller than the absolute permeability. Laboratory and modeling studies show that gas-condensate relative permeability near the well can also depend on interfacial tension and velocity, so a simple constant skin should be interpreted as an engineering lumped parameter rather than a fundamental description [6–10].

For carbonate wells, an intervention that reduces positive skin may be technically justified when pressure-transient analysis, production logging, mineralogical evidence, and operating history support a near-wellbore restriction. Acidizing should not be selected solely because the reservoir is carbonate. The treatment should be matched to mineralogy, water source, scale tendency, reservoir pressure, and fracture architecture. Recent local publications emphasize that acid concentration, injection rate, diversion, temperature, and heterogeneity strongly govern the depth and uniformity of stimulation [16–19,21].

2.3. Liquid-loading criterion and unloading margin

Continuous removal of water and condensate requires sufficient upward gas momentum. The classical Turner-type droplet criterion can be expressed in a general form as:

$$v_{crit} = C_T \left[\frac{\sigma g (\rho_L - \rho_g)}{\rho_g^2} \right]^{1/4} \quad (3)$$

where v_{crit} is the critical superficial gas velocity, σ is gas–liquid interfacial tension, g is gravitational acceleration, ρ_L and ρ_g are liquid and gas densities, and C_T is an empirical coefficient selected for the chosen correlation and unit system [1,2]. Because critical-velocity models can over- or under-predict actual loading under particular well geometries, they are best used together with field symptoms such as tubing/casing pressure divergence, rate cycling, declining liquid recovery, acoustic fluid level, and production logging [3–5].



For screening, the liquid-unloading margin is defined as:

$$M_L = \frac{q_g}{q_{crit}} \quad (4)$$

A value $M_L > 1$ indicates that the calculated gas rate exceeds the critical liquid-removal rate, whereas $M_L < 1$ signals a high risk of liquid accumulation. The value should not be treated as a hard universal boundary. Operational experience, well inclination, condensate fraction, foamer response, pressure, and tubing roughness can shift the practical threshold. In this paper, the margin is used comparatively to show how the candidate interventions change unloading capability.

2.4. Wellbore and surface pressure balance

The flowing bottomhole pressure is linked to wellhead pressure through the total pressure loss in the production string:

$$p_{wf} = p_{wh} + \Delta p_{hyd} + \Delta p_{fr} + \Delta p_{acc} \quad (5)$$

where the three pressure-loss terms denote hydrostatic, frictional, and acceleration components. Liquid accumulation primarily increases Δp_{hyd} , whereas downsizing the tubing to create a velocity string increases gas velocity and generally increases Δp_{fr} . The design problem is therefore an optimization rather than a simple preference for the smallest tubing. A velocity string is beneficial when the improved unloading margin is larger than the penalty created by added friction [3,11,13].

At surface, the wellhead must overcome gathering and separation pressure. Compression decreases the receiving pressure seen by the well, but the compressor must operate within suction, discharge, temperature, power, and turndown limits. A basic compression ratio is:

$$R_c = \frac{p_{dis}}{p_{suc}} \quad (6)$$

and an idealized polytropic power relationship may be expressed as:

$$W = \frac{\dot{m} n}{n-1} R_s T_1 \left[\left(\frac{p_2}{p_1} \right)^{(n-1)/n} - 1 \right] \frac{1}{\eta_p} \quad (7)$$

where $\dot{m}$ is mass flow, n is the polytropic exponent, R_s is the specific gas constant, T_1 is suction temperature, p_1 and p_2 are suction and discharge pressures, and η_p is polytropic efficiency. Equation (7) is used only as a screening expression;



actual compressor selection requires vendor maps, gas composition, anti-surge analysis, driver constraints, cooling, liquid handling, and process safety review.

2.5. Representative engineering case and scenario definitions

A representative depleted carbonate gas-condensate well was constructed to demonstrate the integrated method. It is not presented as a confidential field history. Parameter ranges were chosen to be consistent with late-life gas-condensate behavior reported in the cited literature and with generalized data found in the sources [16–21]. The purpose is reproducibility: all values required to understand the scenario comparison are stated in Table 1.

Table 1. Input parameters for the representative late-life gas-condensate well.

Parameter	Unit	Value	Engineering interpretation
Reservoir pressure, p_r	MPa	13.5	Below dew point; depleted state
Dew-point pressure, p_{dew}	MPa	17.2	Retrograde condensation expected
Reservoir temperature	°C	72	Representative carbonate setting
Net pay thickness, h	m	24	Effective completed interval
Effective gas permeability	mD	18	Before near-well remediation
Baseline skin, S	–	+3.5	Composite damage/condensate effect
Tubing internal diameter	mm	62	Existing production string
Baseline wellhead pressure	MPa	3.2	Surface network constrained
Separator pressure	MPa	2.4	Existing operating level



Parameter	Unit	Value	Engineering interpretation
Water + condensate rate	m ³ /d	6.2	Total liquid entering tubing
Gas rate	10 ³ Sm ³ /d	42	Stable observed/model reference
Calculated unloading margin, M_L	–	0.78	Loading risk
Candidate velocity-string ID	mm	50	Screening alternative
Target compressor suction	MPa	1.3–1.8	Scenario-dependent

Five scenarios were then evaluated. Scenario A retains the base system. Scenario B introduces low-pressure compression without changing the tubing or near-wellbore condition. Scenario C combines compression with a 50-mm velocity string. Scenario D combines compression with selective near-wellbore remediation, reducing effective skin from +3.5 to +0.7. Scenario E combines remediation, velocity management, lower separator/gathering pressure, and compression. The scenario values are not intended as vendor-certified designs; they quantify the direction and magnitude of interaction among constraints.

2.6. Screening rules and performance indicators

The following indicators were used to rank the scenarios: stable gas rate, liquid-unloading margin, wellhead pressure, effective skin, estimated compression energy, and operational complexity. Stable rate is emphasized rather than instantaneous open-flow potential because an intervention that produces a high initial rate but remains below the unloading threshold may not sustain production. Similarly, a rate increase achieved by excessive compression is not considered attractive if the specific compression energy or suction-liquid risk becomes disproportionate.



Table 2. Diagnostic indicators used in the intervention-screening workflow.

Constraint	Screening symptom	Required confirmation	Typical response
Near-wellbore restriction	$S > 2$ or rapidly declining PI	Pressure transient + production history	Selective acidizing / cleanup if compatible
Condensate bank	$p_{wf} < p_{dew}$ and PI loss	PVT + compositional/relative-perm evidence	Pressure management; stimulation; solvent/wettability options
Liquid loading	$M_L < 1$ plus cycling symptoms	Critical-rate screening + field evidence	Velocity string, foamer, plunger/gas lift, compression
High surface backpressure	Large p_{wh} fraction of drawdown	Nodal/network analysis	Separator-pressure reduction; compression
Water influx	Rising water rate and hydrostatic head	PLT, logs, chemistry, pressure behavior	Selective isolation + unloading strategy
Tubing friction	High loss after downsizing	Multiphase tubing model	Re-optimize ID/choke; avoid over-restriction

3. RESULTS

3.1. Scenario comparison

The model results demonstrate that the baseline well is close to the unstable-production region. At 42 thousand Sm³/d, its liquid-unloading margin is only 0.78. This value is consistent with a well that can temporarily produce gas but



progressively accumulates liquids, raises bottomhole pressure, and loses deliverability. Surface compression alone reduces the receiving pressure and raises the stable gas rate to 54 thousand Sm^3/d . However, the corresponding margin of 1.02 leaves little robustness against day-to-day variation in liquid rate, separator pressure, or reservoir pressure.

Adding a velocity string to compression increases the unloading margin to 1.34 and raises stable gas rate to 58 thousand Sm^3/d . The gain is modest compared with compression alone because the smaller internal diameter increases friction. Nevertheless, the operating point is more stable because the well has a larger margin for transporting water and condensate. The result illustrates why a velocity string should be judged by stable production and unloading behavior, not by friction loss alone.

Near-wellbore remediation has a larger rate effect in the representative case. Reducing effective skin from +3.5 to +0.7 while maintaining compression raises stable rate to 71 thousand Sm^3/d and increases M_L to 1.52. This outcome reflects the fact that the base well is constrained simultaneously by inflow and surface pressure. Removing only the surface constraint exposes the inflow limitation; reducing skin then converts the lower surface pressure into additional reservoir drawdown.

The integrated bundle produces the highest stable rate, 76 thousand Sm^3/d , and the largest unloading margin, 1.67. The required wellhead pressure falls to 1.35 MPa. Importantly, the integrated case is not simply the arithmetic sum of individual gains. Each intervention changes the operating point of the others. Lower surface pressure increases gas velocity; improved near-wellbore conductivity increases the flow available to lift liquids; and a tubing configuration that maintains unloading reduces hydrostatic backpressure. This coupling is the central result of the study.

Table 3. Representative scenario results.



Scenario	Gas rate, 10^3 Sm^3/d	M_L	p_{wh} , MPa	Skin	Compression energy, $\text{kWh}/10^3 \text{ Sm}^3$	Interpretation
A. Existing system	42	0.78	3.20	+3.5	0.0	High loading risk
B. Compression only	54	1.02	1.80	+3.5	3.8	Marginal unloading
C. Velocity string + compression	58	1.34	1.80	+3.5	4.2	Stable unloading; friction penalty
D. Remediation + compression	71	1.52	1.80	+0.7	4.0	High rate; monitor liquids
E. Integrated bundle	76	1.67	1.35	+0.5	4.4	Best combined margin

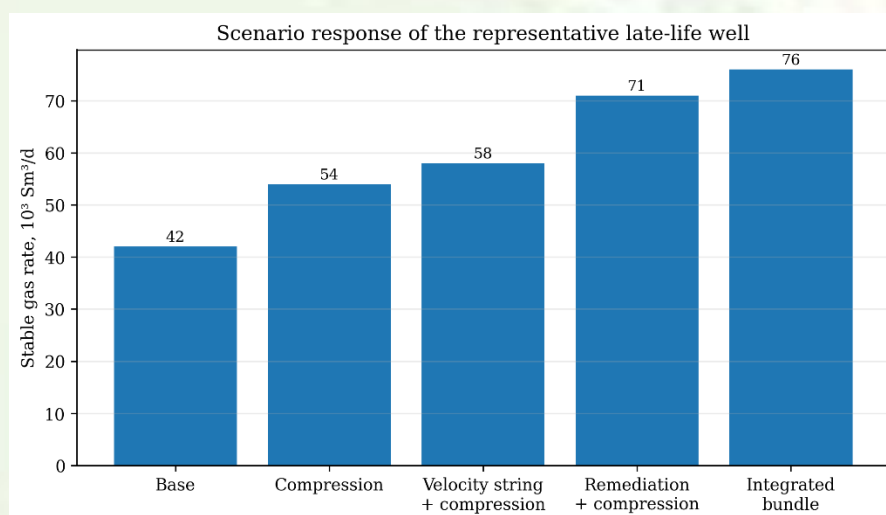


Figure 2. Stable gas-rate response for the five representative operating scenarios.

3.2. Liquid-unloading stability

Figure 3 isolates the effect of each scenario on liquid-unloading capability. The baseline margin is below unity; compression alone moves the well only slightly above the theoretical boundary. This has an important operational implication. If the liquid rate increases after rain-water ingress, water coning, stimulation cleanup, or a change in condensate yield, the compression-only case may again cross into the loaded region. A larger design margin is therefore desirable for wells that show strongly variable liquid rates.

The velocity-string case provides a larger stability margin without requiring a change in the reservoir. This is consistent with field experience reported in the literature, where velocity strings can extend the productive life of mature gas wells, although poor sizing may choke the well [11,13]. The remediation cases achieve even higher margin because they increase gas inflow, not because the critical velocity itself is materially changed. The result emphasizes that liquid unloading can be improved either by lowering the critical requirement or by increasing the gas rate that is available to satisfy it.

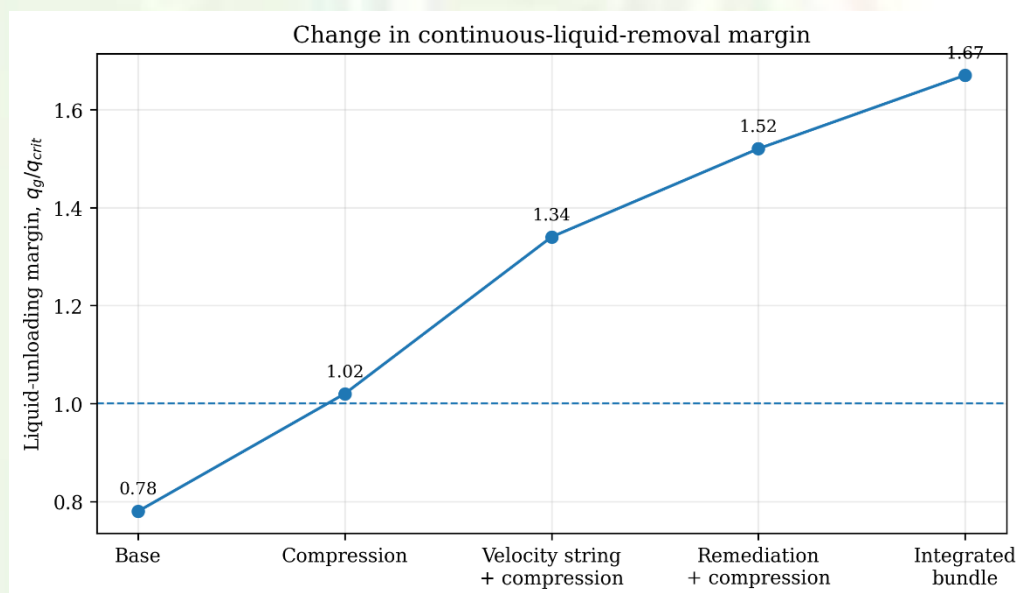


Figure 3. Continuous-liquid-removal margin, expressed as q_g/q_{crit} , for the representative scenarios.

3.3. Surface backpressure and compression interaction

The surface network becomes increasingly important as reservoir pressure declines. Figure 4 compares two representative pressure-demand curves. The base curve includes the existing gathering pressure and additional hydrostatic penalty associated with a loaded tubing string. The integrated curve represents lower gathering/separator pressure and more stable liquid transport. At a given production rate, the integrated system requires less flowing pressure. Alternatively, for the same available pressure drawdown, it supports a higher rate.

This behavior explains why a compressor located at the correct pressure node can deliver more value than a larger compressor installed at an unfavorable node. The objective is not merely to maximize compression ratio. The engineer should minimize the pressure that the reservoir must overcome while respecting compressor suction limits, line pressure, hydrate and liquid-handling constraints, and downstream process requirements. The optimal pressure node may therefore change through field life.

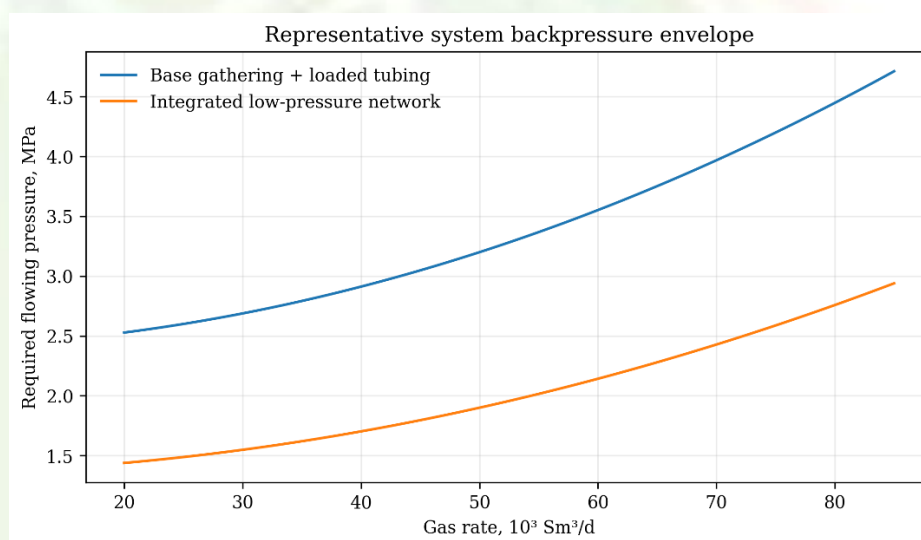


Figure 4. Representative system backpressure envelope before and after integrated low-pressure optimization.

3.4. Sensitivity analysis

A one-at-a-time sensitivity analysis was performed around the integrated scenario. The strongest negative sensitivity is a further 10% reduction in reservoir pressure, which reduces stable gas rate by approximately 18% in the screening model. This confirms that facility and well interventions cannot fully substitute for



reservoir energy. Increased water/condensate load has the second-largest negative effect because it increases hydrostatic pressure and raises the gas velocity needed for continuous unloading. Re-introducing three units of positive skin reduces the rate by about 12%, illustrating the importance of preserving near-wellbore conductivity after treatment.

Increasing separator pressure by 0.7 MPa reduces stable rate by roughly 10%. This sensitivity is important for multiwell gathering systems: a facility change that benefits one well can adversely affect another if common-header pressure rises. Conversely, a 0.4-MPa reduction in compressor suction pressure produces a positive rate response, but the associated energy, temperature, and liquid-handling penalties must be checked. Reducing tubing internal diameter by 18% produces a modest positive rate effect in the representative case because improved unloading outweighs additional friction; this result would reverse in a higher-rate well where friction dominates.

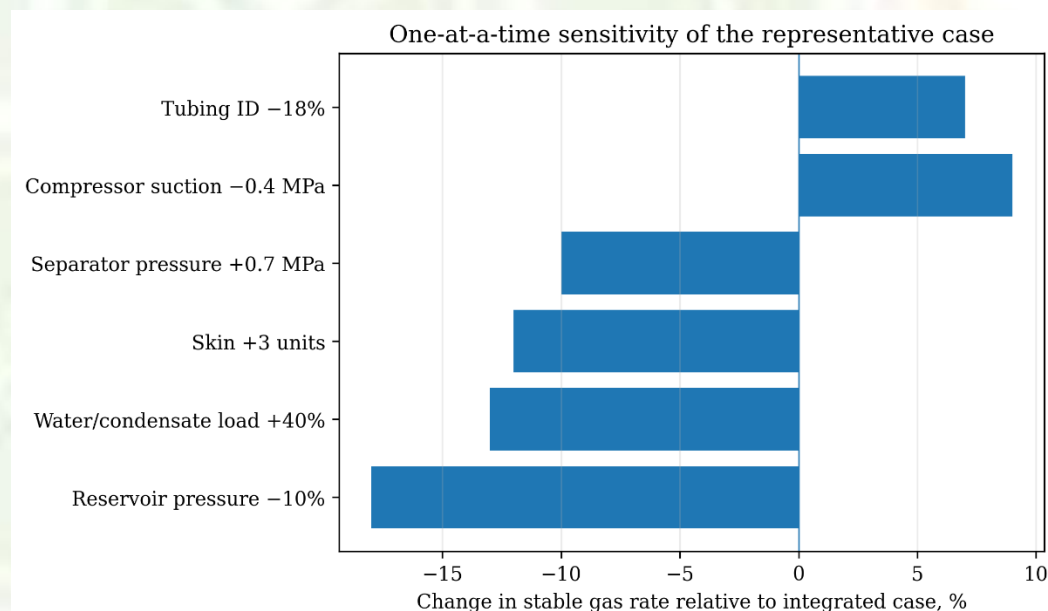


Figure 5. One-at-a-time sensitivity of stable gas rate around the integrated scenario.

Table 4. Sensitivity of the integrated representative case.



Parameter change	Perturbation	Rate change, %	Engineering implication
Reservoir pressure	-10%	-18	Dominant late-life uncertainty; update static/dynamic model
Water + condensate load	+40%	-13	May erase compression benefit if unloading is marginal
Effective skin	+3 units	-12	Check damage recurrence, scale and condensate bank
Separator pressure	+0.7 MPa	-10	Network coordination required
Compressor suction pressure	-0.4 MPa	+9	Positive rate response; verify power and turndown
Tubing ID	-18%	+7	Beneficial only while unloading gain exceeds friction

3.5. Intervention-selection matrix

The scenario results were converted into a practical screening matrix (Table 5). The matrix is not a substitute for field-specific engineering, but it prevents a common error: selecting an intervention because it is technically familiar rather than because it targets the controlling constraint. For example, compression is strongly indicated when the well has adequate inflow potential but is surface-backpressure limited. By contrast, a well with severe skin and a low productivity index should first be evaluated for near-wellbore damage and reservoir access. A well with $M_L < 1$ and significant water influx requires both source control and a liquid-lifting strategy.

Table 5. Intervention-selection matrix for late-life gas-condensate wells.



Observed condition	Likely controlling constraint	Primary action	Key qualification
High skin; $M_L > 1.2$; moderate surface pressure	Near-wellbore restriction	Selective matrix treatment / cleanup	Use mineralogy and logs; avoid stimulating water
Low skin; $M_L < 1$; sufficient reservoir pressure	Wellbore liquid loading	Velocity string / foamer / plunger / gas lift	Choose by liquid type, rate range and completion
Low skin; $M_L \approx 1$; high header pressure	Surface backpressure	Wellhead or centralized compression	Evaluate suction-liquid handling and power
High skin; $M_L < 1$; high surface pressure	Multiple coupled constraints	Remediation + unloading + compression	Preferred candidate for integrated modeling
Rising water rate; unstable pressure cycles	Water influx + loading	Selective water shut-off + unloading	Confirm source before isolation
Very low reservoir pressure; weak inflow	Reservoir energy limitation	Compression may defer abandonment	Check economics and minimum suction pressure

4. DISCUSSION

4.1. Why integrated optimization outperforms isolated actions

The main technical implication of the results is that late-life production constraints are sequentially revealed as other constraints are removed. In the baseline state, a well may appear to be surface-backpressure limited because rate increases when the choke is opened or line pressure falls. After compression is installed, the well may quickly become inflow limited because the additional drawdown is absorbed by condensate banking or positive skin. If stimulation restores inflow, the



well can then become liquid-loading limited. The production system therefore moves through different bottlenecks as it is optimized.

This behavior is consistent with nodal-analysis philosophy: the operating rate is determined by the intersection of inflow and outflow performance. What is specific to late-life gas-condensate wells is that both curves can change as a consequence of multiphase phenomena. Condensate banking shifts the inflow response, liquid accumulation shifts the tubing response, and compression shifts the surface boundary. Treating these effects independently can lead to an intervention that looks attractive in one subsystem but produces only a small change in the actual operating point.

The representative results should not be interpreted to mean that every late-life gas-condensate well requires a velocity string, acid treatment, and compression. The value of the integrated workflow is the opposite: it allows the engineer to eliminate unnecessary interventions. If pressure-transient analysis shows negligible skin, near-wellbore acidizing should not be included. If a well has a large M_L even at forecast end-of-life rate, a velocity string may create unnecessary friction. If gathering pressure is already low, compression may offer little incremental drawdown. Integration is therefore a discipline for constraint matching rather than a prescription for equipment count.

4.2. Condensate banking and the limits of skin-based diagnosis

Condensate banking is often represented as a positive skin because this is convenient for nodal analysis and pressure-transient interpretation. However, the physical process is more complex. Gas and condensate relative permeabilities vary with saturation, interfacial tension, velocity, rock properties, and fluid composition. Experiments have shown that near-wellbore gas relative permeability can increase at high capillary number, partly offsetting the apparent blockage, while inertial effects can act in the opposite direction [7–10]. A single constant skin therefore cannot reproduce all rates and pressures across the life of a gas-condensate well.



For engineering screening, the effective-skin approximation remains useful if its limitations are stated. A practical approach is to calibrate the effective inflow term to recent well tests and use compositional simulation for cases in which condensate banking is expected to dominate project value. Particular attention should be paid to wells where p_{wf} is substantially below the dew point for long periods, where reservoir permeability is low, or where produced condensate-gas ratio is high. In such wells, lowering wellhead pressure can increase both production and the near-well pressure gradient, so the net effect should be evaluated with a compositional model.

Chemical or acid treatment can improve conductivity where mineral scale, drilling/completion damage, or carbonate dissolution potential is present, but it should not be portrayed as a universal condensate-bank removal method. Local studies used in this work focus primarily on carbonate stimulation and physicochemical transformations [16–19,21]. Their relevance to a gas-condensate well is strongest when the near-wellbore restriction includes mineral or formation damage that can be removed or bypassed. If the impairment is dominated by phase behavior rather than rock damage, pressure management, solvent/wettability alteration, fracture conductivity, or gas cycling may be more appropriate [10].

4.3. Deliquification technology selection

Deliquification methods can be grouped by the mechanism through which they restore liquid transport. Velocity strings increase superficial gas velocity by reducing flow area. Foamers reduce effective liquid density and interfacial behavior, thereby reducing the gas momentum required to lift the liquid. Plunger lift creates an interface that improves liquid displacement during cyclic operation. Gas lift and downhole pumps add external energy or directly remove liquid. Compression lowers surface pressure and thereby increases gas rate and available pressure drawdown. Each method has a different operating envelope [3–5,11–13].

The composition of the accumulated liquid is important. A foamer that performs well in produced water may be less effective when the liquid is



predominantly hydrocarbon condensate. Similarly, a velocity string that successfully restarts one well may reduce another well's potential because friction becomes dominant. Field history, fluid samples, temperature, salinity, condensate fraction, corrosion limits, completion geometry, and well deviation should therefore be included in the selection process.

For the representative case, the velocity string becomes attractive only after the surface backpressure is lowered. Under the base pressure condition, downsizing the tubing would not create enough additional drawdown to justify the friction penalty. This illustrates a broader lesson: deliquification options should be screened at forecast operating pressures, not only at current conditions. An intervention intended to extend well life must remain useful as reservoir pressure and liquid production change.

4.4. Compression placement, energy and facility integrity

Compression is one of the most powerful late-life tools because it directly reduces abandonment pressure. Nevertheless, compressor performance should not be assessed only by incremental gas rate. Suction pressure, liquid carryover, gas composition, discharge temperature, compression ratio, driver efficiency, turndown, anti-surge requirements, noise, emissions, maintenance logistics, and hydrate risk all affect feasibility. A mobile or wellhead compressor may be attractive for a small group of wells, whereas centralized compression may be more efficient for a larger network.

Specific compression energy in Table 3 is used only as a comparative indicator. A field decision should be based on a properly simulated compressor map and process model. Particular care is required when a reduction in suction pressure increases condensate or water arrival. The separator and scrubber upstream of the compressor must be able to protect the compressor from liquid ingestion. Likewise, lower pressure can reduce gas density and increase actual volumetric flow through piping and treatment equipment, potentially shifting the bottleneck downstream.



The integrated approach also improves facility integrity management. By forecasting the new flow, pressure, and liquid envelope before intervention, engineers can identify whether the choke, flowline, separator, dehydration unit, or compressor will become the next constraint. This is preferable to maximizing a single-well rate and discovering after startup that common facilities cannot handle the new operating point.

4.5. Economic screening and abandonment pressure

A technically successful intervention can still be uneconomic if the remaining recoverable volume is small or if operating cost is high. A simple screening metric is incremental annual gas production:

$$\Delta G_{yr} = 365 (q_{new} - q_{base}) U \quad (8)$$

where U is an uptime factor. For the representative integrated scenario, the nominal rate increment is 34 thousand Sm³/d. At an illustrative uptime of 0.9, the corresponding incremental annual volume is about 11.2 million Sm³. This value is not a revenue forecast; it is a scale indicator that can be combined with local netback, compression fuel, chemical cost, workover cost, and maintenance to estimate payout.

Late-life projects should also be evaluated by the reduction in technical abandonment pressure rather than only by short-term rate gain. A compression project may produce a moderate initial increase but recover significant additional gas by allowing stable operation at lower reservoir pressure. Conversely, aggressive drawdown can accelerate water encroachment or condensate blockage and shorten useful life. The economic model should therefore be coupled to a forecast, not based solely on an initial post-intervention test.

4.6. Applicability to carbonate fields of southern Uzbekistan

The integrated workflow is particularly relevant to mature carbonate gas-condensate assets where near-wellbore heterogeneity, natural fractures, acid-soluble minerals, pressure depletion, and increasing water production occur simultaneously. The local publications cited in this study provide evidence that carbonate stimulation performance is sensitive to geology, hydrodynamics, temperature, and acid



placement [16–19,21]. Therefore, any late-life optimization program should begin with a well-by-well diagnostic rather than a uniform fieldwide treatment recipe.

A practical field implementation can be organized in three levels. Level 1 is data screening using daily rate/pressure history, condensate and water rates, well test results, separator/header pressure, and intervention history. Level 2 adds pressure-transient analysis, PVT data, critical-velocity screening, and nodal analysis. Level 3 is reserved for high-value or ambiguous wells and includes compositional reservoir simulation, calibrated transient multiphase well modeling, production logging, and detailed compressor/network simulation. This staged approach concentrates engineering effort where uncertainty has the largest economic consequence.

4.7. Limitations and validation requirements

The principal limitation of this paper is that the scenario results are generated from a representative engineering case rather than from a complete field dataset. This choice is intentional because it avoids presenting invented confidential history as measured data. The numerical values therefore illustrate interactions and sensitivities, not guaranteed field performance. Before application to an actual asset, the model must be calibrated to PVT properties, pressure-transient data, production logging, tubing geometry, flowline roughness, separator conditions, and compressor performance.

The critical-velocity approach is also a screening approximation. Mechanistic multiphase models may be required for deviated wells, annular flow, severe slugging, or complex completion geometry. Similarly, a constant skin cannot fully describe rate-dependent condensate-bank behavior. For wells where condensate blocking is a dominant uncertainty, compositional relative-permeability data and fine-grid near-wellbore simulation should be used.

Finally, integrity and safety constraints are not optimized in the numerical scenarios. Every pressure reduction or stimulation project requires verification of wellhead, tubing, packer, flowline, separator, relief, corrosion, erosion, hydrate,



H₂S/CO₂, and emergency shutdown limits. Production optimization is acceptable only inside the safe operating envelope.

5. CONCLUSIONS

1. Late-life gas-condensate production is commonly governed by a coupled constraint set rather than a single bottleneck. Reservoir depletion, condensate banking, positive skin, liquid loading, tubing friction, gathering pressure, and compression capacity should therefore be analyzed as one production system.

2. The representative case showed that surface compression alone increased stable gas rate from 42 to 54 thousand Sm³/d, but the liquid-unloading margin remained close to the theoretical boundary. This indicates that a rate increase is not automatically equivalent to stable late-life operation.

3. Combining compression with a velocity string raised the unloading margin from 0.78 to 1.34. The benefit came from improved gas velocity, although the smaller tubing introduced additional friction. Velocity-string design should therefore be based on nodal and liquid-loading analysis rather than tubing diameter alone.

4. Selective near-wellbore remediation had a stronger rate effect in the representative carbonate case. Reducing effective skin from +3.5 to +0.7 while retaining compression increased stable gas rate to 71 thousand Sm³/d. Such treatment is justified only where diagnostic evidence confirms a removable or bypassable near-wellbore restriction.

5. The integrated scenario—near-wellbore remediation, liquid-unloading management, lower surface backpressure, and compression—produced the most robust operating point: 76 thousand Sm³/d, $q_g/q_{crit} = 1.67$, and a wellhead pressure of 1.35 MPa. The improvement was synergistic because each intervention changed the operating point and effectiveness of the others.

6. Sensitivity analysis identified reservoir pressure, liquid influx, skin recurrence, and separator pressure as the most important negative factors. This supports continuous surveillance after intervention; a successful late-life



optimization program requires active pressure and liquid management rather than a one-time workover.

7. For field application, the proposed workflow should be followed by calibrated compositional reservoir simulation, multiphase well modeling, network simulation, and compressor design. The screening method is most useful for identifying which wells and intervention bundles justify that higher-fidelity work.

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