

Article

A Multi-Objective Constraint Framework for Optimizing Wellhead Pressurization Schemes in Changning Shale Gas Wells

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Abstract

More than 70 shale gas wells have been pressurized in the Changning Block; however, field applications have shown inconsistent stimulation performance and a lack of quantitative guidance for designing rational pressurization schemes. In this study, pressurized shale gas wells in the Changning 201 well area were investigated to establish a multi-objective constraint framework for optimizing pressurization strategies. The framework integrates key techno-economic constraints, including sand production risk, wellbore liquid loading, inflow performance, and incremental gas production. Using fracturing treatment, wellbore configuration, and production performance data from 46 pressurized wells, sand production prediction, liquid-loading diagnosis, and inflow performance analyses were conducted. A quick-look chart was then developed to rapidly determine the optimal pressurization magnitude based on the pre-stimulation gas rate and wellhead pressure of a target well. Field application in nine wells resulted in a total daily incremental gas production of $2.5 \times 10^4 \text{ m}^3 \text{ d}^{-1}$ and an annual cumulative incremental production of $348 \times 10^4 \text{ m}^3$, with production efficiency increasing by 25.9 percentage points. Among ten wells subjected to individual wellhead pressurization, seven achieved the expected performance, whereas the remaining three underperformed because of well-specific constraints. These results demonstrate that the proposed framework can provide quantitative support for rational pressurization design and production restoration in low-pressure shale gas wells.

Keywords: shale gas; wellhead pressurization; multi-objective constraints; rational scheme



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1. Introduction

As the first shale gas demonstration area in China to achieve large-scale commercial development, the Changning Block plays a strategic role in national energy security owing to its high and stable gas production [1–3]. With continued development, most gas wells in this block have entered the middle-to-late production stage, which is characterized by rapid formation pressure depletion, declining wellhead pressure, aggravated wellbore liquid loading, and a continuous decrease in natural productivity. In this context, wellhead pressurization has become an important engineering method for maintaining stable production and recovering remaining production potential by reducing wellhead back pressure and

increasing the production pressure differential [4,5]. However, Luo et al. [6] reported that the production response to pressurization varies substantially among wells. Some wells exhibit limited production improvement, whereas others experience accelerated decline after pressurization. Therefore, scientifically optimized pressurization schemes that account for the complex geological conditions and dynamic production behavior of the Changning Block are essential for its long-term and efficient development.

Wellhead pressurization and boosting technologies have been increasingly applied in different types of gas reservoirs, including water-producing unconsolidated sandstone gas reservoirs, high-sulfur wet gas fields, tight sandstone gas reservoirs, and low-pressure conventional gas reservoirs. Zhu et al. [7] developed a wellhead pressurization system for water-producing unconsolidated sandstone gas reservoirs and emphasized the need to consider low wellhead pressure, liquid accumulation, and sand production risk. Li et al. [8] proposed an optimization method for wet gas pressurization development in high-sulfur gas fields by considering gas–liquid flow behavior, corrosion control, and gathering-system constraints. Xiao et al. [9] optimized a boosting stimulation system for “three-low” tight sandstone gas wells to improve the adaptability of pressurization schemes under low-pressure, low-permeability, and low-productivity conditions. Fan et al. [10] evaluated the pressurization performance of a low-pressure gas reservoir and showed that the production response is closely related to reservoir quality, wellbore flow conditions, and pressure drawdown intensity. These studies provide useful engineering experience for pressurization design; however, their direct application to shale gas wells remains limited because shale gas production is more strongly controlled by fracture-network stress sensitivity, complex gas–water flow behavior and pronounced inter-well heterogeneity.

At present, the design of pressurization schemes in the Changning Block still mainly relies on engineering experience and qualitative analysis, while systematic theoretical guidance and quantitative decision-making models remain insufficient. Three major challenges are commonly encountered in field applications. First, the timing of pressurization is difficult to determine accurately. Premature pressurization increases operating costs unnecessarily, whereas delayed pressurization may miss the optimal window for maintaining stable production [4,6,7]. Second, reliable criteria for determining the magnitude and rate of pressure reduction are still lacking. Excessive pressure reduction may aggravate stress-sensitive fracture damage and destabilize wellbore flow, particularly in low-productivity wells that commonly exhibit an “initial increase followed by rapid decline” after pressurization [6–8]. In contrast, insufficient pressure reduction may fail to effectively release reservoir productivity. Third, substantial differences exist among gas wells in reservoir quality, stimulation effectiveness, wellbore configuration, and liquid loading severity [8,10]. Therefore, the direct application of uniform pressurization parameters to different wells often leads to unsatisfactory production performance. Fundamentally, these problems arise from the absence of an integrated optimization framework that simultaneously considers reservoir flow behavior, wellbore liquid lifting, dynamic fracture conductivity, and economic performance.

Considerable research has been conducted on methods for predicting pressurization timing in gas wells. Zhang et al. [11] analyzed production history data from the Changning 201 well area, predicted the dynamic decline in wellhead pressure, and established a surface gathering pipeline network model to calculate node pressure. In their study, the point at which the predicted wellhead pressure fell below the pipeline network node pressure was defined as the pressurization timing for gas wells. Liang et al. [12] used a constant-volume closed-gas-reservoir pressure decline model for 309 gas wells in the YQ2 well area of the Yan’an Gas Field to calculate the formation pressure depletion rate and predict pressurization timing by comparing simulated wellhead pressure with operating

pressure. Lu [13] established a surface gathering pipeline network model for the Fuling Gas Field using Pipe-Phase software and calculated the critical inlet pressure of the gathering station to support pressurization timing optimization. Wan et al. [14] performed curve fitting for the wellhead pressure of 1400 gas wells in the Daniudi Gas Field to predict pressure trends over the following five years. Based on numerical modeling of the surface gathering pipeline network, they calculated the minimum allowable inlet pressure of the gathering station and used the point at which the predicted wellhead pressure fell below this threshold as the trigger for pressurization.

Despite these advances, several critical gaps remain. First, most existing pressurization timing prediction methods were developed for conventional gas wells or tight gas reservoirs and rely primarily on surface gathering network pressure balance as the main decision criterion. These approaches do not fully account for the complex coupled dynamics of shale gas wells, including proppant-pack stress sensitivity, near-wellbore liquid accumulation, and multi-stage flow-regime transitions that govern production response to depressurization. Second, existing pressurization scheme design methods are predominantly based on a single constraint; they optimize liquid unloading capacity, sand production avoidance, gathering-system adaptability, or pressure drawdown intensity, but rarely integrate these constraints into a unified framework. This single-objective optimization paradigm makes it difficult to identify a pressurization scheme that is simultaneously safe, effective, and economically justified. Third, to the authors' knowledge, no quantitative and differentiated decision-making tool has been developed to enable field engineers to rapidly determine well-specific optimal pressurization magnitudes from readily available production data without relying on complex reservoir simulators.

To address these gaps, this study proposes a multi-objective constraint framework for rational pressurization scheme design, specifically calibrated for shale gas wells in the Changning Block. The framework integrates three techno-economic constraints—sand production risk, wellbore liquid loading, and incremental gas production—into a unified quick-look chart that enables direct, well-specific determination of pressurization schemes using only pre-stimulation wellhead pressure and gas rate data. The primary contributions of this work are as follows: (1) systematic classification of pressurization response patterns and their controlling mechanisms based on dynamic data from 46 pressurized shale gas wells; (2) development and validation of integrated predictive models for sand production and liquid loading under different pressurization magnitudes; and (3) construction of a field-deployable, multi-constraint optimization chart that improved production efficiency by 25.9 percentage points in nine field-applied wells.

2. Materials and Methods

2.1. Study Area and Dataset

This study focuses on the Changning 201 well area in the Changning Block, China's first shale gas demonstration area to achieve large-scale commercial development. The target interval is the Wufeng–Longmaxi Formation shale, which is characterized by high total organic carbon content, well-developed natural fractures, and complex fracture-network geometries generated by multi-stage hydraulic fracturing.

The dataset used in this study includes production performance data, fracturing treatment records, and wellbore configuration parameters from 46 pressurized horizontal shale gas wells in the Changning 201 well area. All wells are multi-stage hydraulically fractured horizontal wells completed in the Wufeng–Longmaxi Formation. The production dataset includes daily gas production rate, wellhead tubing pressure, wellhead casing pressure, liquid production rate, bottomhole flowing pressure, and compressor operating parameters recorded before and after pressurization. The bottomhole flowing pressure was calculated

from wellhead pressure data using wellbore pressure-gradient corrections. Fracturing treatment data, including total proppant mass, proppant type, proppant mesh size, fracture half-length, and injected fluid volume, were obtained from well completion reports. The fracture half-length was interpreted from post-fracturing microseismic monitoring. Wellbore configuration data, including tubing inner diameter, total measured depth, and deviation survey data, were obtained from well design documents.

Based on pre-pressurization production performance, the 46 wells were divided into two categories: high-productivity wells, with a stable pre-pressurization gas rate greater than $5 \times 10^4 \text{ m}^3 \text{ d}^{-1}$, and low-productivity wells, with a stable pre-pressurization gas rate of $5 \times 10^4 \text{ m}^3 \text{ d}^{-1}$ or lower. This classification was used to define the constraint boundaries and construct the quick-look chart in the multi-objective framework described in Section 2.4.

The key well parameters and production data ranges for the 46-well dataset are summarized in Tables 1 and 2. Table 1 presents the static reservoir properties, completion parameters, and wellbore configuration parameters for the two well categories. Table 2 summarizes the statistical ranges of key production and pressurization-related parameters for all 46 test wells, including pre-pressurization wellhead pressure, gas production rate, liquid production rate, average fracture half-length, critical sand production rate, and critical liquid-carrying gas rate. These parameters were used as inputs for the predictive models described in Sections 2.2–2.4 and for constructing the constraint boundaries in the multi-objective framework.

Table 1. Static Well and Completion Parameters by Well Productivity Category.

Parameter	High-Productivity Wells	Low-Productivity Wells	Unit
Number of wells	15	31	/
Pre-pressurization gas rate	$>5 \times 10^4 \text{ m}^3 \text{ d}^{-1}$	$\leq 5 \times 10^4 \text{ m}^3 \text{ d}^{-1}$	$10^4 \text{ m}^3/\text{d}$
Pre-pressurization Wellhead pressure	5~7.6	0.4~2.8	MPa
Liquid production rate	6~18	1	m^3/d
Tubing inner diameter	76	62	mm
Total depth (range)	4500~5448	4500~5448	m

Table 2. Statistical Range of Key Production and Stimulation Parameters for All Test Wells.

Parameter	Minimum	Maximum	Mean	Unit
Pre-pressurization Wellhead pressure	0.4	7.1	2.2	MPa
Pre-pressurization gas rate	0.8	10.69	4.8	$10^4 \text{ m}^3/\text{d}$
Liquid production rate	1	22	4	m^3/d
Average fracture half-length	230	234	232	m
Critical sand production rate	9.56	16.28	13.4	$10^4 \text{ m}^3/\text{d}$
Critical liquid-carrying flow rate	0.63	1.15	0.87	$10^4 \text{ m}^3/\text{d}$

2.2. Formation Sand Production Prediction Model

Sand production occurs when the hydrodynamic drag force exerted by the flowing fluid on proppant particles or weakly consolidated formation particles exceeds the resisting forces provided by particle cohesion, friction, and mechanical confinement. For high-productivity shale gas wells, wellhead pressurization may substantially increase the risk of sand production by altering both the flow field and the mechanical stress state near the wellbore.

The primary effect of pressurization is to reduce wellhead back pressure and bottom-hole flowing pressure, thereby increasing the production pressure differential between

the reservoir and the wellbore. A larger pressure differential results in higher gas velocity within hydraulic fractures and the wellbore. Consequently, the fluid drag force and shear stress acting on proppant particles and loose formation particles increase markedly, which may disturb particle equilibrium and initiate particle migration. In addition, rapid pressure reduction during pressurization can induce pressure fluctuations and unstable flow, generating transient impact forces that further promote the mobilization of weakly retained particles.

The reduction in bottomhole flowing pressure also increases the effective closure stress acting on the proppant pack, natural fractures, and weak structural planes. This effect is particularly important in shale gas reservoirs, where fracture conductivity is highly stress-sensitive. An excessive increase in effective stress may lead to proppant crushing, proppant embedment into relatively soft shale fracture surfaces, and shear failure of fracture-wall rock. These processes not only generate additional fine particles but also weaken the sand-retention capacity of the original proppant pack. As a result, the fracture system becomes more susceptible to particle detachment and transport under high-velocity gas flow.

High-productivity wells generally contain highly conductive and complex fracture networks. After pressurization, gas flow tends to concentrate in dominant high-permeability channels, especially in main fractures near the wellbore. These localized high-velocity zones become potential hotspots for sand production. Meanwhile, the complex flow paths in secondary fractures may further disturb loose particles and contribute to particle migration. Therefore, excessive pressurization may induce formation sand production and cause erosion or damage to the wellbore and surface facilities.

To ensure safe and rational pressurization, the critical production pressure differential for sand production was taken as the upper constraint on the allowable pressurization magnitude. In this study, sand production risk was evaluated by comparing the predicted production pressure differential under different pressurization magnitudes with the critical pressure differential for particle mobilization. The sand production mechanisms considered in this model are schematically illustrated in Figure 1.

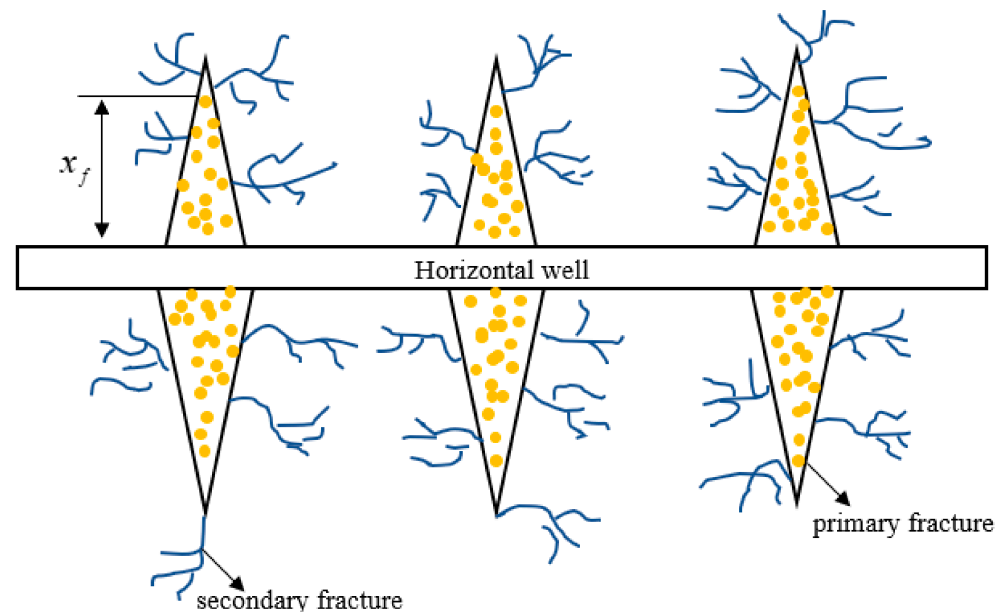


Figure 1. Formation Sand Production Mechanism.

The critical gas velocity for fracture-related sand production was calculated using Equation (1). By integrating this critical velocity with the corresponding fracturing treatment parameters, the critical sand production rate of shale gas wells can be determined.

This provides an important basis for defining a rational initial production allocation during the early production stage and for mitigating the risk of sand production. In this study, the fractures created by hydraulic fracturing were assumed to be wedge-shaped with a triangular cross-section. Under this assumption, the critical flow velocity for sand production within the fracture can be expressed as

$$v_g = \frac{Q}{10^6 \times 60 \times \frac{wd}{1000}} \quad (1)$$

The volume of proppant within the propped fracture is given by

$$V_s = \frac{m}{\rho_s} \quad (2)$$

The total area of the fracture opening face is

$$S_s = \frac{V_s}{x_f} \quad (3)$$

The critical daily gas production rate for sand production is

$$Q_g = 8.64 S_s v_g \quad (4)$$

where V_g is the critical flow velocity for sand production, m/s; Q is the critical sanding flow rate, mL/min; w is the fracture width, m; d is the proppant particle diameter, m; V_s is the volume of proppant within the fracture, m³; m is the mass of proppant within the fracture, t; ρ_s is the bulk density of the proppant, g/cm³; S_s is the total area of the fracture opening surface, m²; x_f is the average fracture half-length, m; and Q_g is the critical gas production rate for sand production, 10⁴ m³/d.

In the above equation, the proppant mass in the fracture was obtained from the fracturing treatment records, and the average fracture half-length was interpreted from post-fracturing microseismic monitoring. The bulk density of the proppant was determined from laboratory measurements. In this study, the measured bulk density was 1.70 g cm^{−3} for 70/140-mesh quartz sand and 1.34 g cm^{−3} for composite fracturing sand.

2.3. Wellbore Liquid Loading Prediction Model

Liquid loading in gas wells is a transient process closely associated with changes in wellbore flow regimes. During liquid lifting, gas–liquid flow causes significant pressure losses along the wellbore, resulting in a nonuniform pressure distribution and the possible coexistence of multiple flow regimes. According to Lea et al. [15], liquid loading in gas wells is strongly related to flow-regime transition within the tubing. In the early production stage, gas wells generally had relatively high production rates, and the tubing flow regime is typically stable in annular flow. As production continues, formation pressure declines, gas production decreases, and churn flow may first appear near the bottom of the tubing. With further decline in gas rate, churn flow gradually develops upward, leading to unstable gas–liquid flow and the accumulation of liquid slugs at the tubing bottom. If the gas rate continues to decrease, bubble flow may occur near the wellbore bottom, and the well may eventually become unable to lift liquid to the surface.

The transition from annular flow to churn flow is generally regarded as the onset of liquid loading because it is commonly accompanied by a sharp decline in production rate and unstable wellbore flow. Under such conditions, the gas phase can no longer continuously and effectively carry liquid to the surface, resulting in liquid accumulation in the wellbore and, in severe cases, well shut-in. Therefore, predicting the critical liquid-carrying

gas rate is essential for evaluating the lower operational boundary of wellhead pressurization. In this study, the liquid loading constraint was incorporated into the multi-objective pressurization framework by comparing the predicted gas production rate under different pressurization magnitudes with the corresponding critical liquid-carrying gas rate. The wellbore liquid loading mechanisms considered in this model are illustrated in Figure 2.

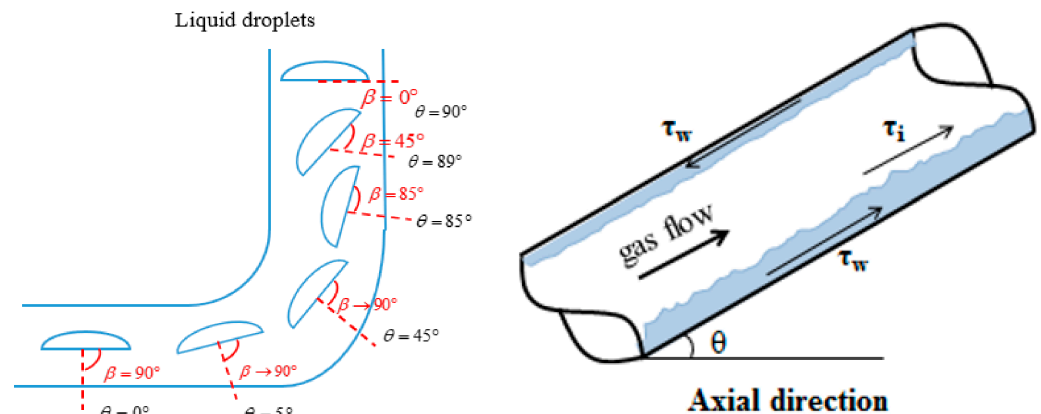


Figure 2. Wellbore Liquid Loading Mechanisms.

For horizontal and highly deviated wells, Belfroid et al. [16] incorporated the Fiedler shape function, which better captures the effect of inclination angle on the critical liquid-carrying velocity, into a vertical-well droplet model containing inclination-related terms. This equation led to the Belfroid critical liquid-carrying model, which is now widely used for inclined and horizontal wellbores.

Based on the force balance of liquid droplets in a vertical wellbore, the critical gas velocity for liquid carrying can be expressed as

$$v_{cr} = 1.9 \left[\frac{N_{we} \sigma (\rho_l - \rho_g)}{C_d \rho_g^2} \right]^{0.25} \quad (5)$$

By applying the Fiedler model shape function to the droplet model described above, the calculation expression for the critical liquid-carrying velocity in inclined pipes is obtained as

$$v_{cr} = \left(\frac{4C}{3M \cdot C_d} \right)^{0.5} \left[\frac{\sigma (\rho_l - \rho_g)}{\rho_g^2} \right]^{0.25} \cdot \frac{(\sin 1.7\theta)^{0.38}}{0.74} \quad (6)$$

In Equation (6), the third term represents the added inclination-dependent correction term, which is applicable within an inclination angle range of 0–90°. Following the same theoretical framework, the more widely applicable Turner droplet model [17] was adopted as the base model. By incorporating the tubing inclination angle correction, substituting $C = 0.44$ and $M = 30$ into Equation (6), and increasing the resulting coefficient by 20% as a safety margin, the critical liquid-carrying gas velocity for inclined wellbores can be expressed as

$$v_{cr} = 5.5 \left[\frac{\sigma (\rho_l - \rho_g)}{C_d \rho_g^2} \right]^{0.25} \frac{(\sin(1.7\theta))^{0.38}}{0.74} \quad (7)$$

where v is the critical gas velocity, m/s; q is the minimum gas flow rate required for continuous liquid transport, $10^4 \text{ m}^3/\text{d}$; A is the tubing cross-sectional area, m^2 ; p is the pressure, MPa; T is the temperature, K; and Z is the gas compressibility factor.

2.4. Inflow Performance and Nodal Analysis

After wellhead pressurization, the bottomhole flowing pressure decreases, and the production pressure differential between the reservoir and the wellbore increases. However, the incremental gas production obtained under different pressurization magnitudes is not linear and may vary substantially among wells. Therefore, sensitivity calculations were performed to quantify the gas production increment under different pressurization magnitudes and to identify the pressurization magnitude with the most favorable economic benefit.

Rational production allocation was determined using nodal system analysis. In this method, the bottomhole was selected as the analysis node, and the single-well production system was divided into two coupled flow components: inflow from the reservoir to the bottomhole and outflow from the bottomhole to the wellhead through the wellbore. Under specified wellhead pressure conditions, the inflow performance relationship and outflow performance relationship were established. The intersection of the inflow and outflow performance curves represents the stable operating point of the gas well and was used to determine the rational production allocation after pressurization.

In this study, nodal analysis was conducted under different wellhead pressure scenarios to evaluate the production response to varying pressurization magnitudes. The corresponding gas production increment was then compared with the constraints of sand production risk and wellbore liquid loading to determine the optimal pressurization magnitude within the multi-objective framework. The nodal analysis workflow for high-productivity wells is shown in Figure 3.

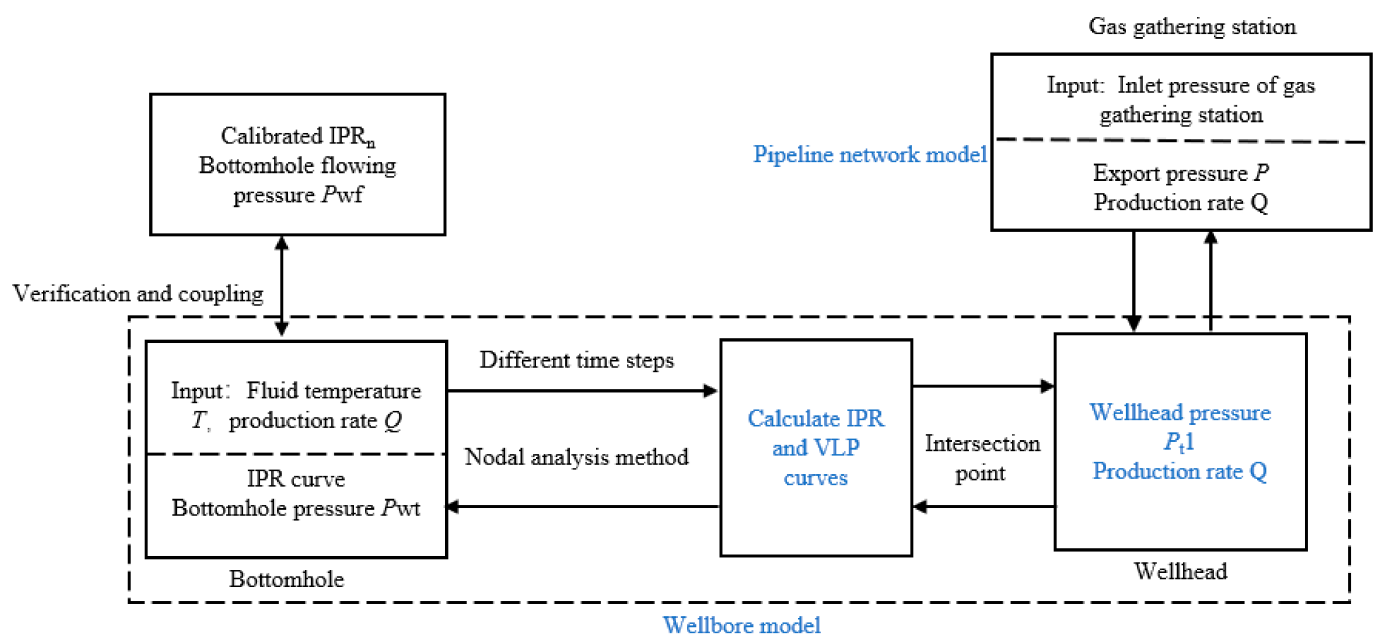


Figure 3. Workflow of Nodal Analysis for High-productivity Wells.

Based on the wellbore configuration parameters and dynamic production data, wellbore models were established for each horizontal gas well. Well test data were then integrated to provide the fundamental input parameters for productivity evaluation. According to the pseudo-steady-state gas productivity equation proposed by Al-Hussainy et al. [18], the productivity of horizontal gas wells can be calculated as follows:

$$q_h = \frac{3.676 \times 10^{-4} k_h h (p_e^2 - p_{wf}^2)}{\mu Z T \ln\left(\frac{r_{eh}}{r_w}\right)} \quad (8)$$

The IPR model improved by Bendakhlia, based on the Vogel equation [19], is given as

$$\frac{q_0}{q_{0,\max}} = \left[1 - V \left(\frac{p_{wf}}{p_R} \right) - (1 - V) \left(\frac{p_{wf}}{p_R} \right)^2 \right]^n \quad (9)$$

where q_h is the gas flow rate, $10^6 \text{ m}^3/\text{d}$; p_e is the outer boundary pressure, 10^{-3} MPa ; p_{wf} is the bottomhole flowing pressure, 10^{-3} MPa ; k_h is the horizontal permeability, 10^{-4} mm^2 ; h is the reservoir thickness, m; r_{eh} is the reservoir drainage radius, m; μ is the average gas viscosity, $10^{-3} \text{ Pa}\cdot\text{s}$; Z is the average gas compressibility factor, dimensionless; T is the reservoir temperature, $^\circ\text{C}$; V is the inertial turbulence coefficient, dimensionless, and related to the gas well deliverability coefficient; p_R is the average reservoir pressure, 10^{-3} MPa ; and r_w is the wellbore radius, m.

The Hagedorn & Brown method [20] is recommended for calculating pressure drops in vertical or near-vertical gas–liquid two-phase flow pipelines, with the total pressure drop equation given as:

$$\frac{dp}{dz} = \rho_m g + f_m \frac{G_m^2}{2DA^2\rho_m} \quad (10)$$

$$\rho_m = \rho_l H_1 + \rho_g (1 - H_1) \quad (11)$$

$$G_m = G_g + G_l = A(v_{sl}\rho_l + v_{sg}\rho_g) \quad (12)$$

The two-phase friction coefficient f_m is calculated using the Jain equation [21]:

$$f_m = \left[1.14 - 2\lg \left(\frac{e}{D} + \frac{21.25}{Re_m^{0.9}} \right) \right]^{-2} \quad (13)$$

where p is the average pressure of the flowing medium within the pipe segment dl , MPa; l is the length of the pipe segment, m; H_L is the liquid holdup, dimensionless; λ is the hydraulic friction coefficient for gas–liquid two-phase flow, dimensionless; ρ_l is the liquid-phase density, kg/m^3 ; ρ_g is the gas-phase density, kg/m^3 ; d is the inner pipe diameter, m; w_m is the gas–liquid mixture velocity, m/s; w_{sg} is the superficial gas velocity, m/s; ρ_m is the density of the gas–liquid mixture, kg/m^3 ; D is the inner pipe diameter, m; v_{sg} and v_{sl} are the superficial gas and liquid velocities, respectively, m/s; f is the two-phase friction factor, dimensionless; G is the mass flow rate of the gas–liquid mixture, kg/s ; and Re is the no-slip Reynolds number for gas–liquid two-phase flow, dimensionless.

2.5. Multi-Objective Constraint Framework

The three models described above provide three independent constraint boundaries for each well under different pressurization magnitudes:

- (1) Constraint 1—sand production upper bound: the wellhead pressure should not be reduced to a level at which the predicted gas production rate exceeds the critical sand production rate, (Q_g), calculated using Equation (4).
- (2) Constraint 2—liquid loading lower bound: the wellhead pressure should be reduced sufficiently to ensure that the predicted gas production rate exceeds the critical liquid-carrying gas rate, (q), calculated using Equation (7), thereby maintaining continuous liquid removal.
- (3) Constraint 3—economic efficiency bound: the marginal gas production increment per unit reduction in wellhead pressure should remain positive and exceed the minimum economic threshold, ensuring that pressurization is economically justified.

For a given well, the feasible pressurization window was defined as the wellhead pressure range that satisfies all three constraints simultaneously. Using the stable gas

production rate and wellhead pressure before pressurization as coordinates, the optimal post-pressurization wellhead pressure for a target well can be directly determined from the resulting quick-look chart without iterative numerical simulation. Separate quick-look charts were constructed for high-productivity and low-productivity wells to account for differences in their dominant constraint mechanisms.

The quick-look charts were constructed as follows. First, the pre-pressurization wellhead pressure and gas production rate of the 46 wells were extracted from daily production reports. Second, the sand production model, liquid loading model, and nodal analysis model were applied sequentially to calculate the three constraint boundaries for each well using Equations (4), (7), (8) and (9), respectively. Third, the wells were divided into high-productivity and low-productivity groups according to their stable pre-pressurization gas production rates. Fourth, the feasible pressurization window for each well was mapped onto a two-dimensional coordinate system, with pre-pressurization wellhead pressure on the x -axis and pre-pressurization gas production rate on the y -axis. Finally, boundary curves separating different optimal post-pressurization pressure zones were fitted to generate independent quick-look charts for the two well groups.

3. Results

3.1. Classification of Pressurization Response Patterns

3.1.1. Pressurization Characteristics of High-Productivity Wells

A statistical analysis was performed to examine the relationship between gas production rate and wellhead pressure after pressurization in high-productivity shale gas wells. As shown in Figures 4–6, the production response to decreasing wellhead pressure can be classified into three patterns: continuous increase, initial decrease followed by increase, and increase–decrease–increase.

In the continuous-increase pattern shown in Figure 4, gas production increases monotonically after wellhead pressure reduction and eventually reaches a stable state. This behavior is mainly attributed to the strong reservoir supply capacity and improved wellbore flow conditions, with no significant flow restrictions during pressurization. In such wells, reservoir pressure remains relatively high, permeability is favorable, and gas deliverability is sufficient. Therefore, reducing wellhead pressure directly increases the production pressure differential, allowing gas flow from the reservoir to the wellbore to remain in an adequate-supply and smooth-flow state. In addition, the wellbore flow regime is maintained as stable single-phase gas flow or efficient mist flow, resulting in relatively low frictional pressure loss. As a result, the pressure reduction at the wellhead can be effectively transmitted to the bottomhole, thereby enhancing gas production from the reservoir.

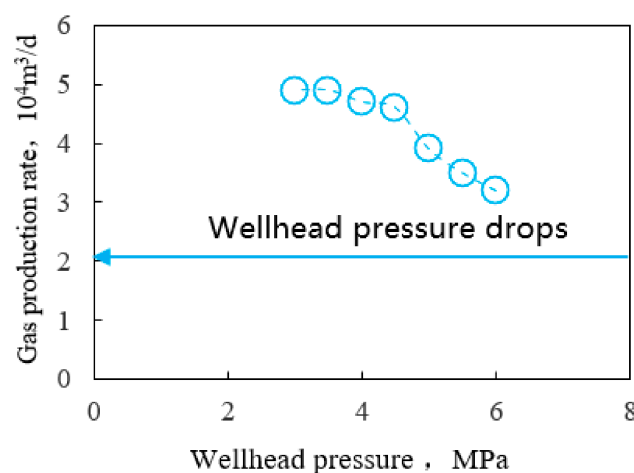


Figure 4. Continuous Increase Pattern in Well N209H64-3.

In the initial decrease followed by an increase pattern shown in Figure 5, gas production does not increase immediately after the initial reduction in wellhead pressure; instead, it first declines and then increases markedly once the wellhead pressure is reduced below a critical level. This response is mainly controlled by wellbore liquid loading. In this case, the initial pressure reduction deteriorates the wellbore flow regime, whereas further pressure reduction promotes liquid unloading and flow-regime restructuring.

Before pressurization, a certain amount of condensate or formation water had already accumulated in the wellbore. During the early stage of wellhead pressure reduction, the gas velocity in the wellbore does not increase sufficiently to enhance liquid lifting. Meanwhile, gas expansion and intensified gas–liquid slip may cause the flow regime to shift from annular mist flow to slug flow, temporarily reducing the liquid-carrying capacity of the gas phase and aggravating liquid loading. The accumulated liquid increases the additional hydrostatic back pressure in the wellbore, partially offsetting the effect of wellhead pressure reduction and resulting in a temporary decline in gas production.

As the wellhead pressure is further reduced, the production pressure differential continues to increase and the bottomhole flowing pressure decreases, thereby accelerating gas inflow from the reservoir. Once the gas velocity exceeds the critical liquid-carrying velocity, the accumulated liquid in the wellbore can be effectively lifted to the surface, and the flow regime gradually changes from inefficient slug flow to efficient annular mist flow. After successful wellbore unloading, flow resistance decreases substantially, the bottomhole flowing pressure is effectively reduced, reservoir inflow is fully stimulated, and gas production begins to increase significantly.

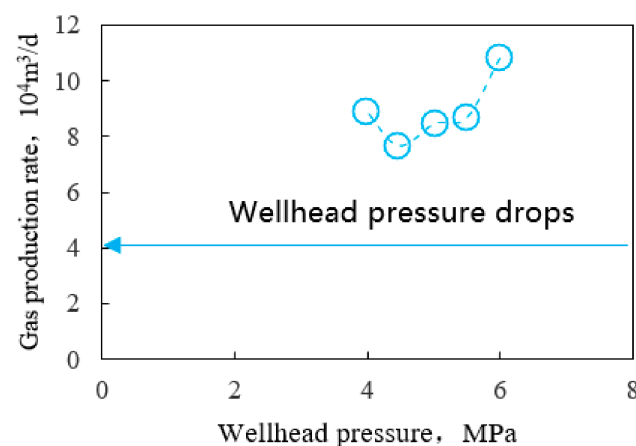


Figure 5. Initial Decrease Followed by Increase Pattern in Well N209H64-4.

In the increase–decrease–increase pattern shown in Figure 6, gas production increases rapidly during the initial stage of wellhead pressure reduction, then enters a plateau or slightly declines as the pressure continues to decrease within a certain range and finally increases again with further pressure reduction. This nonmonotonic response reflects the coupling and competition among multiple mechanisms, with the dominant control shifting at different stages of pressurization.

In the first stage, the production response is mainly controlled by near-wellbore blockage removal and pressure-differential drive. The initial reduction in wellhead pressure rapidly increases the production pressure differential, which enhances the mobilization of free gas and desorbed gas in the near-wellbore region. Meanwhile, pressure reduction may promote the reopening of near-wellbore microfractures or displace retained fracturing fluid and condensate away from the near-wellbore zone, temporarily improving flow conductivity. As a result, gas production increases rapidly.

In the second stage, the production response is governed by the competition between aggravated liquid loading and fracture stress sensitivity. As the wellhead pressure continues to decrease, gas expansion and the Joule–Thomson cooling effect may become more pronounced, potentially promoting condensate accumulation or hydrate formation under favorable conditions. If the increase in gas velocity is insufficient to maintain stable liquid carrying, the wellbore flow may re-enter an unstable regime, leading to renewed liquid accumulation and increased flow resistance. In addition, the conductivity of hydraulically induced fractures in shale reservoirs is highly sensitive to effective stress. When the bottomhole flowing pressure decreases to a certain level, the effective stress acting on fracture surfaces increases, which may cause partial closure of microfractures or propped fractures. This reduces fracture conductivity and partially offsets the positive effect of the increased production pressure differential, causing gas production to plateau or decline slightly.

In the third stage, further pressure reduction allows the system to reach a new flow equilibrium and activates deeper reservoir supply. As gas velocity stabilizes above the critical liquid-carrying velocity, liquid removal becomes more continuous and efficient, and wellbore flow resistance decreases to a lower level. Meanwhile, the larger production pressure differential generated by the reduced bottomhole flowing pressure helps overcome flow resistance in deeper reservoir regions or lower-permeability zones, thereby expanding the effective drainage area and contributing additional gas supply. Consequently, gas production increases again.

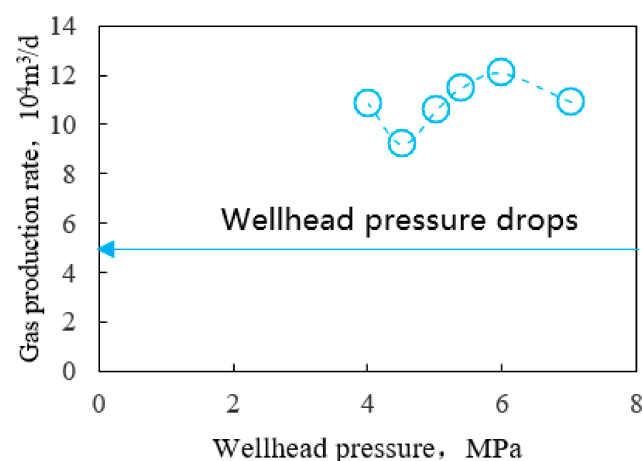


Figure 6. Increase–Decrease–Increase Pattern in Well N209H64-5.

3.1.2. Pressurization Characteristics of Low-Productivity Wells

The initial increase followed by a decrease pattern observed in low-productivity wells reflects the competition between the short-term pressure-differential stimulation effect and the long-term limitations imposed by insufficient reservoir supply and flow-system deterioration. The initial production increase is typically short-lived and mainly results from the rapid depletion of readily mobile gas in the near-wellbore region. In contrast, the subsequent production decline represents the dominant long-term trend, indicating that low-productivity wells cannot maintain stable production solely through wellhead pressure reduction. This two-stage response is illustrated by the field examples of three low-productivity wells shown in Figure 7a–c.

In the first stage, gas production temporarily increases as the pressure-differential drive effect becomes rapidly enhanced. A reduction in wellhead pressure directly decreases the bottomhole flowing pressure and increases the production pressure differential between the reservoir and the wellbore. This enhanced driving force first mobilizes free gas and readily desorbed gas within the stimulated reservoir volume around the wellbore. Although

low-productivity wells generally have limited resource abundance and poor permeability, a certain amount of mobile gas may still exist within the near-wellbore fracture network. Therefore, the initial increase in pressure differential can effectively produce this readily available near-wellbore gas, resulting in a transient production peak. In addition, if slight liquid loading is present before pressurization, the temporary increase in gas velocity may exceed the critical liquid-carrying velocity, promoting short-term liquid removal, reducing wellbore flow resistance, and further enhancing the apparent stimulation effect. Thus, the production increase in this stage mainly represents the rapid recovery of limited gas already connected to the wellbore. The magnitude of the production peak depends on the initial fracture conductivity and near-wellbore free gas storage, whereas its duration is constrained by the supply capacity of the distant matrix. As shown in Figure 7a, Well N209H35-1 exhibits a pronounced but short-lived production peak shortly after pressurization, which is consistent with this mechanism.

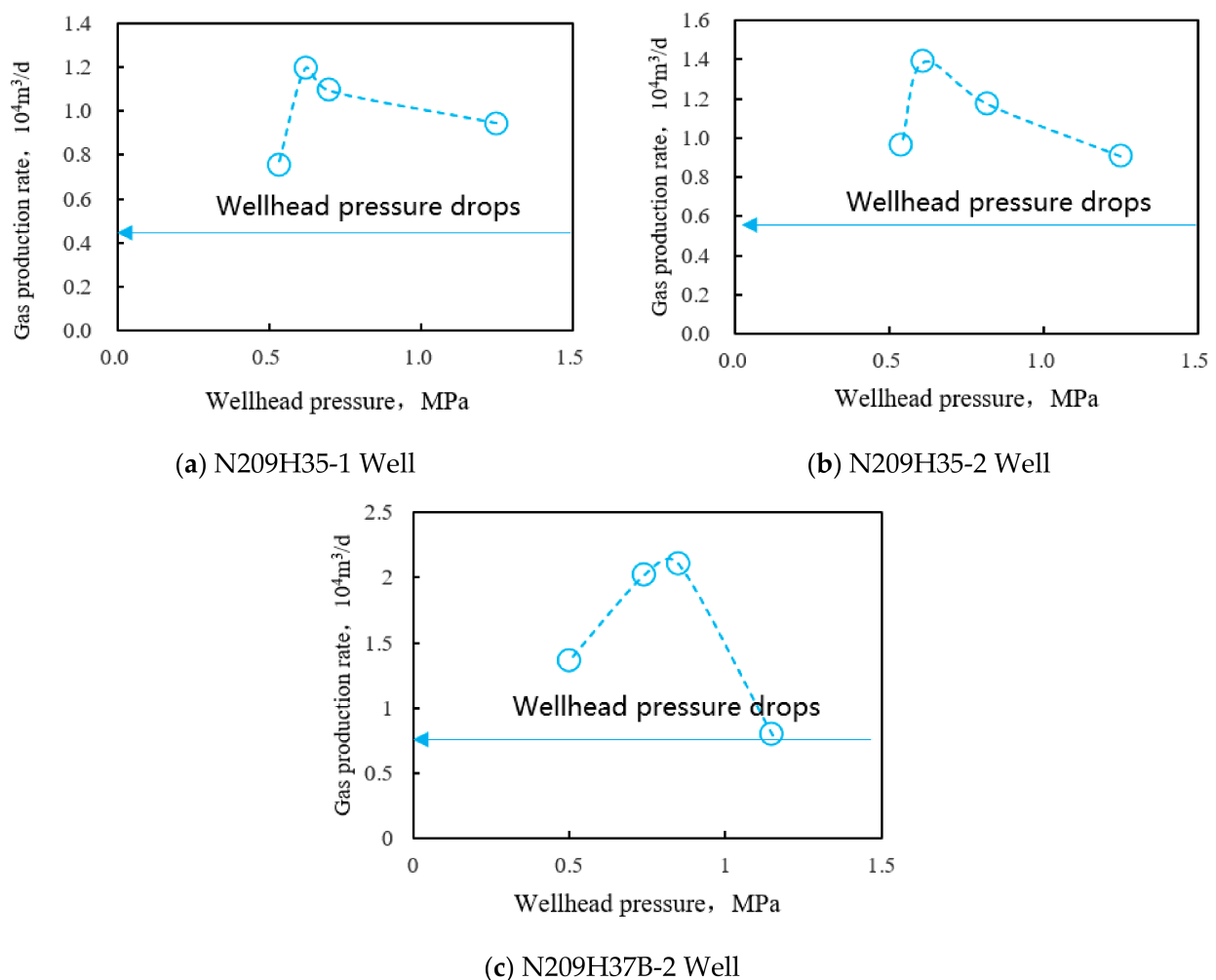


Figure 7. Pressurization Characteristics in Low-Productivity Wells.

In the second stage, gas production declines continuously as reservoir energy becomes depleted and matrix supply lags behind wellbore withdrawal. In low-productivity shale gas wells, matrix permeability is extremely low, commonly at the nanodarcy scale, and gas migration from matrix pores to the fracture network is therefore very slow. The early-stage production increases rapidly depletes gas within the near-wellbore fracture network and forms a steep pressure-depletion zone around the wellbore. Gas desorption, diffusion, and migration from the distant matrix to the wellbore occur over a much longer timescale and cannot replenish the near-wellbore fracture system at the same rate as

gas extraction. Consequently, even when the bottomhole flowing pressure remains low, insufficient reservoir supply leads to an inevitable decline in production.

As production decreases from its peak, the gas velocity may again fall below the critical liquid-carrying velocity. Under these conditions, liquid begins to re-accumulate in the wellbore, and liquid removal becomes more difficult because of the weakened reservoir energy. The additional hydrostatic back pressure caused by liquid loading further restricts gas inflow, forming a negative feedback process of production decline, intensified liquid loading, increased back pressure, and further production decline. The sustained post-peak decline observed in Figure 7b and 7c for Wells N209H35-2 and N209H37B-2, respectively, is consistent with this mechanism.

Notably, Well N209H37B-2 in Figure 7c shows a more pronounced initial increase followed by a sharp decline than the wells shown in Figure 7a,b. This response can be attributed to poorer fracture-network connectivity and a steeper near-wellbore pressure-depletion zone, as indicated by its lower dynamic reserve estimate. After pressurization, the limited near-wellbore gas is rapidly depleted, whereas the extremely low matrix permeability prevents sufficient gas replenishment from the distant matrix within the production timescale. As a result, production declines more rapidly. The associated sharp decrease in gas velocity further promotes liquid re-accumulation in the wellbore, intensifying the negative feedback between production decline and liquid loading.

3.2. Sand Production Prediction Results

The sand production prediction model described by Equation (4) was applied to four representative high-productivity wells on the N209H64 platform. Critical sand production rates were calculated under progressive wellhead pressure reduction scenarios, and the results are summarized in Table 3. The calculated critical production rates differ among the four wells, ranging from 9.56×10^4 to 16.28×10^4 m³ d^{−1}. These differences are mainly controlled by fracturing treatment and production-related parameters, including total proppant volume, which reflects the scale of the propped fracture system, and liquid production rate, which affects gas–liquid flow behavior and particle-carrying capacity.

Table 3. Prediction of Formation Sand Production under Different Pressurization Magnitudes.

Well ID	Wellhead Pressure	Gas Production Rate ^a	Liquid Production Rate	Total Sand Volume	Average Fracture Length	Critical Sand Production Rate	With/Without Sand Production ^b
N209H64-3	6	3.2/3.2	18	4268	230	10.81	N
	4.8	3.7	18	4268	230	10.81	N
	3.6	4.1/4.7	18	4268	230	10.81	N
	2.4	4.6	18	4268	230	10.81	N
	1.2	5.0	18	4268	230	10.81	N
N209H64-4	7.1	10.0/10.0	27	4480	230	13.24	N
	5.6	12.1/9.82	27	4480	230	13.24	N
	4.1	13.9	27	4480	230	13.24	Y
	2.6	15.5	27	4480	230	13.24	Y
	1.1	16.7	27	4480	230	13.24	Y
N209H64-5	7	10.9/10.9	30	4980	230	16.28	N
	5.5	13.1/10.94	30	4980	230	16.28	N
	4	15.1/10.60	30	4980	230	16.28	N
	2.5	16.9	30	4980	230	16.28	Y
	1	18.2	30	4980	230	16.28	Y
N209H64-6	6.9	9.1/9.1	25	4149	230	9.56	N
	5.4	11.9/11.0	25	4149	230	9.56	Y
	3.9	13.9/7.4	25	4149	230	9.56	Y
	2.4	15.6	25	4149	230	9.56	Y
	0.9	16.9	25	4149	230	9.56	Y

Note: ^a Values before and after the slash represent predicted and observed gas production rates, respectively. ^b Y indicates the occurrence or predicted risk of sand production/liquid loading; N indicates no predicted occurrence.

For Well Ning 209 H64-3, the actual gas production rate remained consistently below the predicted critical sand production rate under all evaluated wellhead pressure reduction scenarios. Therefore, even when the wellhead pressure was reduced to the minimum evaluated level, the predicted sand production risk remained low.

The results indicate that wells with larger total proppant volumes and longer fracture half-lengths tend to have higher critical sand production rates, thereby providing a wider operational margin for pressurization. However, avoiding sand production alone is insufficient for defining a rational pressurization scheme. The wellbore liquid loading constraint must also be satisfied to ensure that the selected pressurization magnitude is both safe and operationally effective.

3.3. Liquid Loading Prediction Results

After pressurization, the increased production pressure differential can release additional reservoir potential and increase gas production. However, once the gas production rate exceeds the critical liquid-carrying gas rate, further pressure reduction may provide limited additional production benefit while increasing wellbore friction losses and compressor power consumption. Therefore, from the perspectives of energy efficiency and economic viability, the critical liquid-carrying gas rate was used as an important constraint for determining a rational pressurization magnitude.

Table 4 presents the predicted liquid loading status of each well under different pressurization magnitudes. The evaluation was performed by comparing the predicted or actual gas production rate with the corresponding critical liquid-carrying gas rate. Wells with gas production rates higher than the critical liquid-carrying gas rate were considered capable of maintaining continuous liquid removal, whereas wells below this threshold were identified as having a potential risk of liquid loading.

Table 4. Prediction of Wellbore Liquid Loading under Different Pressurization Magnitudes.

Well ID	Wellhead Pressure	Gas Production Rate	Liquid Production Rate	Bottomhole Flowing Pressure	Critical Liquid-Carrying Flow Rate	With/Without Liquid Loading
CNH6-1	1.2	0.90	1	2.3	1.1	Y
	1.0	0.98	1	2.1	1.0	Y
	0.8	1.03	1	1.9	0.89	N
	0.6	1.04	1	1.6	0.77	N
	0.4	1.05	1	1.4	0.63	N
CNH6-2	1.2	0.90	1	2.3	1.1	Y
	1.0	0.98	1	2.1	1.0	Y
	0.8	1.03	1	1.9	0.89	N
	0.6	1.04	1	1.6	0.77	N
	0.4	1.05	1	1.4	0.63	N
CNH6-3	1.3	0.90	1	2.4	1.15	Y
	1.1	0.98	1	2.2	1.06	Y
	0.9	1.03	1	2.0	0.95	Y
	0.7	1.04	1	1.8	0.83	N
	0.5	1.05	1	1.5	0.70	N

To validate the predictive capability of the critical liquid-carrying gas rate model under field conditions, the model predictions were compared with eight independent acoustic echometer measurements from seven shale gas wells in the Changning Block. The acoustic echometer provides a direct diagnostic measurement of downhole liquid accumulation by transmitting an acoustic pulse through the annulus and interpreting the reflected signal to identify the gas–liquid interface depth. Therefore, it was used as an independent indicator of wellbore liquid loading status.

For each validation case, the critical liquid-carrying gas rate, Q_{cr} , was calculated using measured wellbore temperature, pressure, and tubing configuration data based on Equation (7). The liquid loading status was then predicted by comparing the actual daily gas production rate with Q_{cr} . Cases with gas production rates lower than Q_{cr} were classified as liquid-loaded, whereas those with gas production rates higher than Q_{cr} were classified as liquid-free. The model-predicted classifications were then compared with concurrent acoustic echometer diagnostic results, as summarized in Table 5.

As shown in Table 5, the model correctly predicted the liquid loading status of all eight validation cases, corresponding to a prediction accuracy of 100%. Six cases with gas production rates higher than Q_{cr} were correctly identified as liquid-free, whereas two cases with gas production rates lower than Q_{cr} , namely CN M25 and CN M23, were correctly identified as liquid-loaded. These results indicate that the parameterized Belfroid-based inclined-wellbore critical liquid-carrying model can reliably identify wellbore liquid accumulation under typical downhole conditions in Changning shale gas wells [13,21].

Table 5. Validation of Liquid Loading Predictions Against Field Acoustic Echometer Measurements.

Well ID	Temp. (°C)	Pressure (MPa)	Gas Rate ($10^4 \text{ m}^3/\text{d}$)	Q_{cr} ($10^4 \text{ m}^3/\text{d}$)	Model Prediction	Echometer Diagnosis
CN M9	24.43	3.22	2.60	2.39	No loading	No loading
CN M15	20.54	5.05	8.00	3.00	No loading	No loading
CN M28	30.01	4.79	6.14	2.88	No loading	No loading
CN M29	26.99	6.62	7.43	3.40	No loading	No loading
CN M33	19.24	5.61	6.61	3.18	No loading	No loading
CN M15	25.70	5.05	4.58	2.98	No loading	No loading
CN M25	20.93	3.11	1.06	2.36	Liquid loading	Liquid loading
CN M23	29.02	4.92	2.80	2.92	Liquid loading	Liquid loading

Note: CN M15 was measured twice under different operating conditions; therefore, Table 5 includes eight field measurements from seven shale gas wells.

3.4. Gas Production Increment Prediction

Nodal analysis was conducted for both high-productivity and low-productivity gas wells, as shown in Figure 8. The simulation results indicate that wellhead pressure reduction can effectively improve gas well deliverability, restore flow capability in wells approaching flow cessation, and further extend the effective production period under liquid-loading conditions.

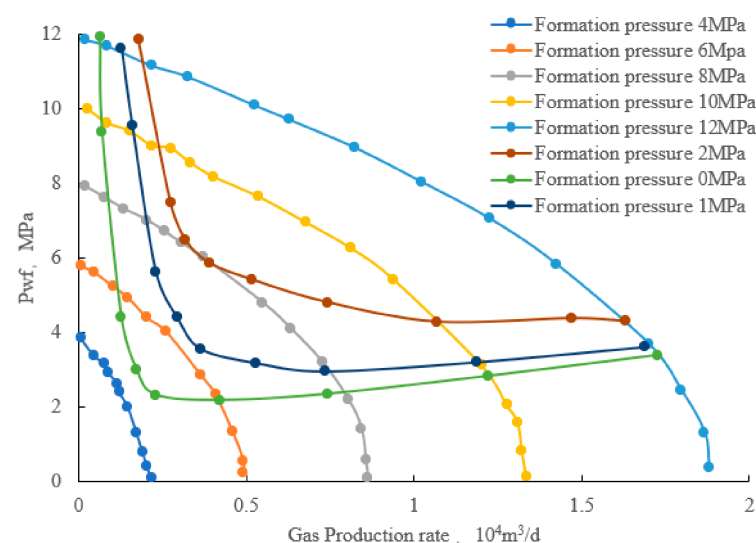


Figure 8. Nodal Analysis Results Under Different Wellhead Pressure Scenarios.

At a wellhead pressure of 2 MPa, the wells gradually lose their ability to maintain stable flow as formation pressure declines, even with foam-assisted deliquification. Type I and Type II wells represent the two representative well categories used in the nodal analysis, corresponding to different reservoir supply capacities. For Type I wells, the simulated formation pressure at the onset of flow cessation is approximately 8 MPa, with a corresponding nodal production rate of about $0.43 \times 10^4 \text{ m}^3 \text{ d}^{-1}$. For Type II wells, the corresponding formation pressure is approximately 14 MPa, with a nodal production rate of about $0.58 \times 10^4 \text{ m}^3 \text{ d}^{-1}$.

When the wellhead pressure is reduced to 0 MPa, gas production can be restored in wells that would otherwise cease flowing under higher wellhead pressure conditions. At a formation pressure of 8 MPa, the simulated gas production rate of Type I wells increases to approximately $0.78 \times 10^4 \text{ m}^3 \text{ d}^{-1}$. At a formation pressure of 14 MPa, the simulated gas production rate of Type II wells increases to approximately $0.94 \times 10^4 \text{ m}^3 \text{ d}^{-1}$. These results demonstrate that wellhead pressure reduction can substantially improve gas production by increasing the production pressure differential.

Further reduction in the wellhead pressure to 0 MPa also lowers the formation pressure threshold required to maintain liquid-carrying production. For Type I wells, the flow-cessation formation pressure decreases to approximately 4 MPa, with a corresponding nodal production rate of about $0.18 \times 10^4 \text{ m}^3 \text{ d}^{-1}$. For Type II wells, the threshold decreases to approximately 9 MPa, with a corresponding nodal production rate of about $0.25 \times 10^4 \text{ m}^3 \text{ d}^{-1}$. These results indicate that the combined pressurization and foam-assisted deliquification process enables gas wells to maintain liquid-carrying production at rates close to $0.2 \times 10^4 \text{ m}^3 \text{ d}^{-1}$, reducing the flow-cessation formation pressure by approximately 4–5 MPa compared with foam-assisted deliquification alone.

For low-pressure, low-productivity gas wells with simultaneous gas and water production, reservoir quality remains a key factor controlling the production response to pressurization. Under similar formation pressure conditions, wells with better reservoir quality exhibit higher productivity and a stronger response to the combined pressurization and deliquification process.

The nodal analysis results demonstrate that pressurization has considerable potential for production recovery, particularly for wells approaching natural flow cessation. To quantify the gas production increment under each pressurization magnitude at current production conditions, sensitivity calculations were performed for wells on the CNH6 platform. The predicted production increments under different wellhead pressures are summarized in Table 6.

As shown in Table 6, the marginal production increment per unit reduction in wellhead pressure decreases progressively as the wellhead pressure is lowered. Across the evaluated pressure range, the marginal increment decreases from 0.09×10^4 to $0.01 \times 10^4 \text{ m}^3 \text{ d}^{-1}$. This diminishing marginal return indicates that excessive pressure reduction may provide limited additional production benefit while increasing operational cost, and it therefore defines the economic efficiency boundary in the multi-objective constraint framework.

3.5. Quick-Look Optimization Charts

Based on the multi-objective constraints of sand production risk, wellbore liquid loading, and pressurization benefit, quick-look optimization charts were established to determine rational wellhead pressurization schemes. For a target well, the stable daily gas production rate and corresponding wellhead tubing pressure before pressurization were obtained from daily production reports. The target well was then plotted on the corresponding quick-look chart, from which the recommended post-pressurization wellhead pressure range could be directly determined. All optimization charts were generated using

Python 3.10 (Python Software Foundation, Wilmington, DE, USA) with the Matplotlib 3.x library.

Table 6. Prediction of Gas Production Increment under Different Pressurization Magnitudes.

Well ID	Wellhead Pressure	Gas Production Rate	Liquid Production Rate	Bottomhole Flowing Pressure	Magnitude of Gas Production Increase
CNH6-1	1.2	0.90	1	2.3	0.09 0.05 0.01 0.01 0.01
	1.0	0.98	1	2.1	
	0.8	1.03	1	1.9	
	0.6	1.04	1	1.6	
	0.4	1.05	1	1.4	
CNH6-2	1.2	0.90	1	2.3	0.09 0.05 0.01 0.01 0.01
	1.0	0.98	1	2.1	
	0.8	1.03	1	1.9	
	0.6	1.04	1	1.6	
	0.4	1.05	1	1.4	
CNH6-3	1.3	0.90	1	2.4	0.09 0.05 0.01 0.01 0.01
	1.1	0.98	1	2.2	
	0.9	1.03	1	2.0	
	0.7	1.04	1	1.8	
	0.5	1.05	1	1.5	

Figure 9 presents the quick-look optimization chart for high-productivity wells. In this chart, the horizontal axis represents the wellhead tubing pressure before pressurization, the vertical axis represents the daily gas production rate before pressurization, and the legend indicates the recommended post-pressurization wellhead pressure under different operating conditions. As shown in Figure 9, the optimization regions for high-productivity wells exhibit clear and continuous boundaries, with each region covering a relatively large control area and showing no obvious stepwise transition.

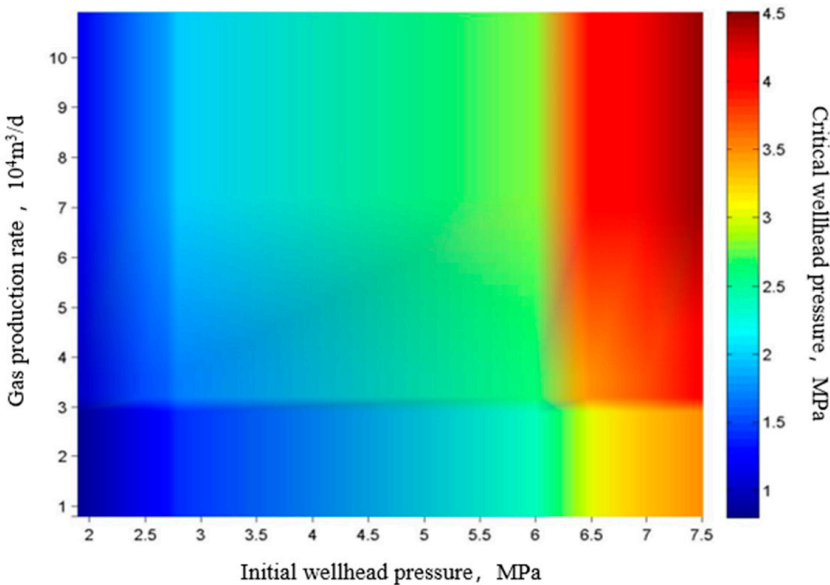


Figure 9. Optimization Chart for Pressurization Schemes in High-Productivity Gas Wells.

This distribution is mainly attributed to the strong reservoir supply capacity of high-productivity wells. These wells generally have relatively high reservoir pressure, favorable permeability, and sufficient gas deliverability. Therefore, reducing wellhead pressure can directly increase the production pressure differential and maintain gas flow from the reservoir to the wellbore under an adequate-supply and smooth-flow conditions. Under these

conditions, the dominant constraint on pressurization is not reservoir supply capacity or liquid unloading, but the risk of sand production induced by excessive pressure reduction. Consequently, the recommended pressurization magnitude for high-productivity wells is primarily controlled by the sand production constraint.

Figure 10 presents the quick-look optimization chart for low-productivity wells. In this chart, the horizontal axis represents the wellhead tubing pressure before pressurization, the vertical axis represents the daily gas production rate before pressurization, and the legend indicates the recommended post-pressurization wellhead pressure under different operating conditions.

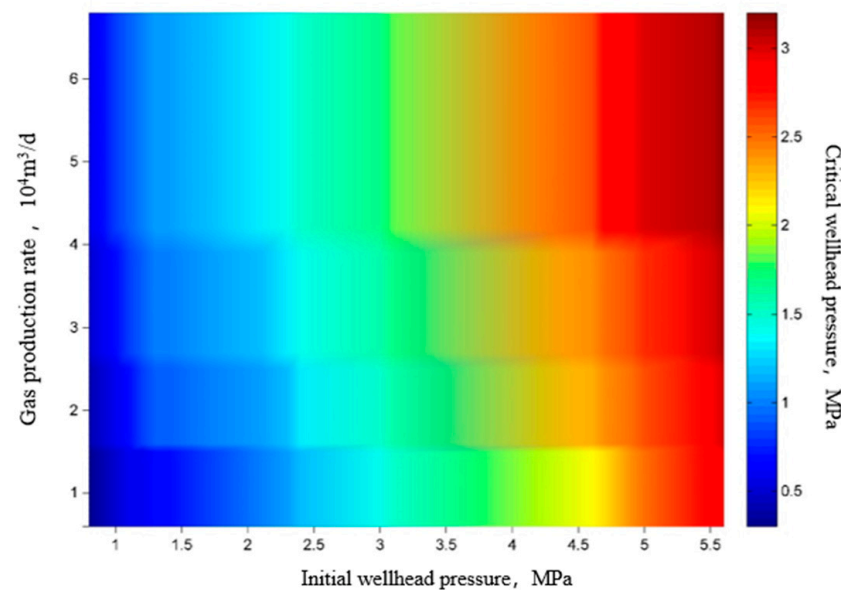


Figure 10. Optimization Chart for Pressurization Schemes in Low-Productivity Gas Wells.

Compared with the chart for high-productivity wells shown in Figure 9, the optimization chart for low-productivity wells exhibits narrower feasible regions and more tightly constrained pressure ranges. This difference reflects the inherently limited reservoir supply capacity of low-productivity wells. Because matrix permeability is commonly at the nanodarcy scale, gas replenishment from the distal matrix to the fracture network is slow, making these wells more susceptible to production decline and liquid re-accumulation when the pressurization magnitude is excessive.

Accordingly, the pressurization scheme for low-productivity wells is mainly constrained by the balance between achieving sufficient liquid unloading and avoiding excessive near-wellbore pressure depletion caused by over-pressurization. If the pressure reduction is insufficient, gas velocity may remain below the critical liquid-carrying threshold, resulting in liquid accumulation. Conversely, excessive pressure reduction may rapidly deplete the limited near-wellbore gas supply, aggravate stress-sensitive fracture conductivity loss, and generate a steep pressure-depletion zone near the wellbore. Therefore, the feasible pressurization window for low-productivity wells is substantially narrower than that for high-productivity wells, highlighting the need for individualized, well-specific optimization rather than uniform block-level parameter application.

Traditional empirical methods generally determine pressurization timing based on the critical liquid-carrying gas rate of a single well or historical operational experience. However, these methods often neglect the coupled effects of sand production risk, reservoir gas supply capacity, and economic benefit. As a result, they may lead to operational problems such as excessive pressurization, which can induce sand production or particle

blockage, or insufficient pressurization, which may fail to remove accumulated liquid and eventually cause production interruption.

Single-constraint methods, such as those considering only liquid-carrying capacity or sand production avoidance, may provide accurate estimates for a specific indicator but cannot fully represent the actual operating boundary of a gas well under multi-factor coupling. Consequently, the resulting schemes may be either overly conservative or operationally risky. In contrast, the quick-look optimization charts developed in this study incorporate sand production risk, wellbore liquid-carrying capacity, and pressurization benefit as simultaneous constraints. This framework covers the key decision-making chain from safe production to economic feasibility and reduces the bias associated with optimizing a single indicator.

3.6. Field Application and Performance Evaluation

3.6.1. Overview of the Target Platforms

The field application involved the CN209-73 and CNH6-2 platforms. The four gas wells on the CN209-73 platform were put into production in June 2024. Wellbore models were established using gas well design parameters and then incorporated into the integrated production model. The maximum platform gas production rate during the early production stage reached $24.73 \times 10^4 \text{ m}^3 \text{ d}^{-1}$. However, with continued production, the wellhead pressure declined rapidly.

During the middle-to-late production stage, the wells entered an intermittent production phase, and the wellhead pressure decreased at an average rate of approximately $0.0087 \text{ MPa d}^{-1}$. Approximately 332 days after commissioning, the wellhead pressure declined from 6.7 MPa to 3.47 MPa, which no longer satisfied the normal transmission pressure requirement of the platform. Based on the prediction method proposed in this study, pressurization measures were designed for each gas well in June 2025. Field implementation showed that compressors were installed on the platform in June 2025, which was consistent with the predicted pressurization timing. The implemented pressurization measures effectively improved the production performance of the gas wells.

3.6.2. Optimization of Pressurization Scheme

The production performance of each individual well on the CN209-73 platform was statistically analyzed. Based on the quick-look optimization charts developed in this study, the pressurization scheme for each well was optimized, and the predicted gas production increments under different pressurization levels are summarized in Table 7.

Table 7. Gas Production Increment Prediction for Varying Pressurization Intensities in the CN209-73 and CNH6-2 Platforms.

Platform	Well ID	Wellhead Pressure	Gas Production Rate	Liquid Production Rate	Magnitude of Gas Production Increase
CN209-73	1	1.2	0.90	1	
	2	1.0	0.98	1	0.09
	3	0.8	1.03	1	0.05
	4	0.6	1.04	1	0.01
CNH6-2	1	1.2	0.90	1	
	2	1.0	0.98	1	0.09
	3	0.8	1.03	1	0.05
	4	0.6	1.04	1	0.01
	5	0.4	1.05	1	0.01

3.6.3. Application Performance Evaluation

Table 8 summarizes the predicted gas production increments under different pressurization levels. For the nine wells that implemented individual wellhead pressurization, the total daily incremental gas production after pressurization reached $2.5 \times 10^4 \text{ m}^3 \text{ d}^{-1}$, and the annual cumulative incremental production reached $348 \times 10^4 \text{ m}^3$. The production efficiency increased by 25.9 percentage points. After pressurization, the average wellhead back pressure of each well decreased by 0.6 MPa, the average single-well elastic productivity increased by $140 \times 10^4 \text{ m}^3 \text{ MPa}^{-1}$, and the dynamic reserves increased by $786 \times 10^4 \text{ m}^3$. These results indicate that wellhead pressurization significantly improved the production performance of the target wells.

Table 8. Field Performance Before and After Individual Wellhead Pressurization.

No.	Before Pressurization					After Pressurization			
	GPR, $10^4 \text{ m}^3/\text{d}$	PRF, %	EP, $10^4 \text{ m}^3/\text{MPa}$	DR, 10^4 m^3	GPR, $10^4 \text{ m}^3/\text{d}$	PRF, %	EP, $10^4 \text{ m}^3/\text{MPa}$	DR, 10^4 m^3	Incremental Production, $10^4 \text{ m}^3/\text{d}$
X1	0.3	100	240	1847	0.6	100	321	2936	0.3
X2	0.1	68.3	800	5790	0.6	100	1200	6480	0.5
X3	0.4	89.5	712	5087	0.5	99.5	799	7988	0.1
X4	0.3	73.9	500	4700	0.4	92.4	620	5600	0.1
X5	0.2	93.8	357	4459	0.4	97.4	400	5480	0.2
X6	0.4	90.2	274	2569	0.8	98.7	315	2860	0.4
X7	0	0	140	2890	0.7	88.8	650	3400	0.7
X8	0	0	29	667	0	0	67	760	0
X9	0	0	52	1248	0.2	95	60	1374	0.2

Note: GPR is the gas production rate; PRF is the production rate factor; EP is the elastic productivity; DR is the dynamic reserve.

To further evaluate the effectiveness of individual well pressurization, ten wells were compared in terms of production efficiency, pressure response, gas production rate, wellbore pressure gradient, elastic productivity, and dynamic reserves before and after pressurization. Among these wells, seven achieved the expected pressurization performance, whereas two did not meet the expected response.

For the seven wells with effective pressurization responses, the post-pressurization operating rate reached 100%, representing an increase of 23 percentage points compared with the pre-pressurization level. The average tubing pressure and casing pressure were 1.4 MPa and 3.0 MPa, respectively. The total daily incremental gas production reached $2.3 \times 10^4 \text{ m}^3 \text{ d}^{-1}$, and the production efficiency increased from 73.7% to 96.7%. In addition, the average single-well elastic productivity increased by $182 \times 10^4 \text{ m}^3 \text{ MPa}^{-1}$, and the dynamic reserves increased by $1057 \times 10^4 \text{ m}^3$.

For the three wells that did not achieve the expected pressurization response, the average tubing pressure and casing pressure were 1.4 MPa and 2.2 MPa, respectively. Owing to reservoir- and wellbore-related constraints, these wells failed to maintain normal production after pressurization, and no significant improvement was observed in either elastic productivity or dynamic reserves.

3.6.4. Model Cross-Validation and Error Metrics

To evaluate the predictive reliability and generalization ability of the proposed framework, leave-one-out cross-validation (LOOCV) was performed using the dataset of 46 wells from the Changning 201 well area. The sample size for each component model differed because each model was validated using the subset of wells with complete field measurements for the corresponding constraint. The results are summarized in Table 9. Overall, the framework correctly classified 40 of the 46 wells, corresponding to an overall classification accuracy of 87.0%.

Table 9. Leave-One-Out Cross-Validation (LOOCV) Performance Summary for the Multi-Objective Constraint Framework.

Well Category	<i>n</i>	Correctly Classified	Classification Accuracy (%)	MAE of $P_{wp,opt}^a$ (MPa)	RMSE of $P_{wp,opt}^a$ (MPa)	R^2 of $P_{wp,opt}^a$
High-productivity wells ($q_0 > 5 \times 10^4 \text{ m}^3/\text{d}$)	15	13	86.7	0.31	0.38	0.87
Low-productivity wells ($q_0 \leq 5 \times 10^4 \text{ m}^3/\text{d}$)	31	27	87.1	0.18	0.24	0.92
Overall	46	40	87.0	0.22	0.29	0.91

Note: $P_{wp,opt}^a$ is the optimal post-pressurization wellhead pressure.

For high-productivity wells, defined as wells with ($q_0 > 5 \times 10^4 \text{ m}^3/\text{d}$, $n = 15$), the classification accuracy was 86.7%. The mean absolute error (MAE) of the predicted optimal post-pressurization wellhead pressure, P_{wp} , was 0.31 MPa; the root mean square error (RMSE) was 0.38 MPa; and the coefficient of determination, R^2 , was 0.87. For low-productivity wells, defined as wells with ($q_0 \leq 5 \times 10^4 \text{ m}^3/\text{d}$, $n = 31$), the framework showed slightly better predictive performance, with a classification accuracy of 87.1%, an MAE of 0.18 MPa, an RMSE of 0.24 MPa, and an R^2 of 0.92.

The overall LOOCV metrics, including an MAE of 0.22 MPa, an RMSE of 0.29 MPa, and an R^2 of 0.91, indicate that the proposed multi-objective constraint framework has strong predictive reliability and generalization capability. The error metrics of the three-component prediction models are further summarized in Table 10. The results show that all three models achieved satisfactory predictive performance, supporting their applicability in the integrated pressurization optimization framework.

Table 10. Summary of error metrics for the three predictive models.

Model	Metric	Value	N
Sand Production Prediction	Accuracy	92.5%	20
	Precision	93.4%	20
	Recall	98.0%	20
	F1-Score	0.92	20
Liquid Loading Prediction	Accuracy	93.3%	15
	Precision	96.3%	15
	Recall	85.7%	15
	F1-Score	0.923	15
Production Increment (Nodal Analysis)	R^2	0.9932	9
	RMSE	$0.0173 \times 10^4 \text{ m}^3/\text{d}$	9
	MAE	$0.0078 \times 10^4 \text{ m}^3/\text{d}$	9
	MAPE	2.50%	8

4. Discussion

4.1. Mechanistic Interpretation of Pressurization Response Patterns

The three distinct production response patterns observed in high-productivity wells—continuous increase, initial decrease followed by increase, and increase–decrease–increase—reflect the dynamic competition among reservoir supply capacity, wellbore flow-regime transitions, and fracture stress sensitivity during progressive pressure reduction. These patterns are broadly consistent with the flow-regime transition framework described by Lea et al. [15], in which the onset of liquid loading is associated with the transition from annular mist flow to churn flow. However, the present study further extends this framework by showing that, in shale gas wells with complex fracture networks, a secondary production recovery stage, characterized by an increase–decrease–increase

response, may occur after near-wellbore liquid unloading is achieved and deeper reservoir supply is activated. This late-stage recovery is likely related to the contribution of distal low-permeability matrix blocks, a mechanism that has rarely been addressed in previous pressurization studies mainly focused on conventional gas wells [12,13,22].

For low-productivity wells, the initial increase followed by a rapid decline pattern reveals a fundamental limitation of pressure-differential-driven production enhancement in low-abundance reservoirs. After pressurization, the readily mobile gas in the near-wellbore region is rapidly depleted, whereas nanodarcy-scale matrix permeability limits timely replenishment from the distal matrix. This supply–demand mismatch is primarily controlled by reservoir quality and cannot be fully resolved by optimizing pressurization timing or magnitude alone. This finding has direct practical implications. For wells exhibiting this response pattern, pressurization optimization remains necessary, but supplementary measures, such as re-fracturing or foam-assisted deliquification, should be considered concurrently to improve long-term production performance.

4.2. Advantages of the Multi-Objective Constraint Framework over Single-Constraint Approaches

Previous pressurization scheme design in the Changning Block and analogous shale gas fields has mainly relied on single-constraint criteria, such as the critical liquid-carrying gas rate [15–17] or empirical wellhead pressure thresholds [6,22,23]. Although these approaches are operationally simple, they cannot fully capture the coupled risks that may arise during pressurization. For example, a scheme designed solely to enhance liquid unloading may reduce the wellhead pressure below the safe operating threshold for sand production, thereby inducing proppant mobilization, particle migration, and potential wellbore or surface equipment erosion. Conversely, a scheme based only on sand production avoidance may result in insufficient pressure reduction, preventing effective liquid removal and limiting production recovery.

The multi-objective constraint framework developed in this study addresses this limitation by simultaneously incorporating three independent boundary conditions: (i) the critical gas production rate for sand production, which defines the upper safety boundary; (ii) the critical liquid-carrying gas rate, which defines the lower operational boundary for stable liquid removal; and (iii) the marginal gas production increment per unit pressure reduction, which defines the economic efficiency boundary. Integrating these three constraints into a single quick-look optimization chart represents the primary methodological contribution of this work. Rather than providing only a single deterministic pressure value, the framework identifies a feasible pressurization window that satisfies safety, production stability, and economic efficiency requirements simultaneously.

The quick-look chart approach is conceptually consistent with nodal-analysis-based optimization methods [24–26], but it substantially reduces the computational burden and is therefore more suitable for rapid field decision-making. Once the chart has been constructed, field engineers can determine the recommended post-pressurization wellhead pressure using readily available production data, without repeated wellbore simulation or complex reservoir modeling. This balance between predictive accuracy and operational practicality is consistent with the design philosophy of field-oriented decision tools developed for conventional gas wells [27].

5. Conclusions

This study investigated the production behavior of pressurized shale gas wells in the Changning Block and developed a multi-objective constraint framework for rational wellhead pressurization design. The main conclusions are as follows:

- (1) The production characteristics of pressurized shale gas wells were systematically analyzed. Based on key techno-economic indicators, including sand production risk, wellbore liquid loading, and incremental gas production, a multi-objective constraint framework was established to support rational pressurization scheme design.
- (2) Using fracturing treatment data, wellbore configuration parameters, and production performance data from 46 pressurized shale gas wells, sand production prediction, liquid loading diagnosis, and inflow performance analysis were conducted. Based on the proposed multi-objective constraint framework, quick-look optimization charts were developed, enabling rapid determination of the optimal pressurization magnitude from the pre-stimulation gas rate and wellhead pressure of a target well.
- (3) Field application in nine wells demonstrated the effectiveness of the proposed framework. After pressurization, the total daily incremental gas production reached $2.5 \times 10^4 \text{ m}^3 \text{ d}^{-1}$, and the annual cumulative incremental production reached $348 \times 10^4 \text{ m}^3$. The production efficiency increased by 25.9 percentage points, indicating a substantial improvement in production performance.

Despite these promising results, several limitations should be acknowledged. First, the quick-look charts were calibrated using production data from 46 wells in the Changning 201 well area, and their applicability to other shale gas blocks with different geological settings, such as deep shale or marine–continental transitional shale, requires further validation. Second, the current framework treats sand production risk, wellbore liquid loading, and incremental gas production as independent constraints. Future studies should further investigate the coupling among these factors under transient pressurization conditions using dynamic simulation. Third, integrating machine learning algorithms, such as random forest or gradient boosting, with the proposed framework may enable real-time adaptive optimization of pressurization schemes as production conditions evolve. Finally, a life-cycle economic evaluation model that incorporates carbon emission costs should be developed to support low-carbon decision-making in shale gas production engineering.

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Conflicts of Interest: Authors Bing Feng, Yun Dai, Hongquan Wang, Yi He, Liangzhu Guo, Qiang Zhang, Xin Luo and Xue Hu were employed by the company Sichuan Changning Natural Gas Development Co., Ltd., PetroChina Southwest Oil & Gasfield Company. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

Nomenclature

V_g	critical sanding flow velocity, m/s
Q	critical sanding flow rate, mL/min
w	fracture width, m
d	proppant particle diameter, m
V_s	the volume of proppant in the fracture, m ³
ρ_s	bulk density of the proppant in the fracture, g/cm ³
S_s	total area of the fracture opening face, m ²
x_f	average fracture half-length, m
Q_g	the critical daily gas production rate for sand production, 10 ⁴ m ³ /d
v	critical gas velocity, m/s
q	minimum gas flow rate required for liquid droplet transport, 10 ⁴ m ³ /d
A	tubing cross-sectional area, m ²
P	pressure, MPa
T	temperature, K
Z	gas deviation factor
P_e	pressure at the outer boundary, 10 ⁻³ MPa
K_h	horizontal permeability, 10 ⁻⁴ mm ²
R_{eh}	reservoir drainage radius, m
v_{sg}, v_{sl}	superficial velocities of gas and liquid phases, respectively, m/s
f	two-phase friction factor, dimensionless
G	mass flow rate of gas–liquid mixture, kg/s

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