

Drawdown-driven sand production in gas-lift wells

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Abstract. Gas-lift operation in weak consolidated sandstone can increase drawdown and exaggerate sand-related completion impairment, while sparse surveillance often prevents mechanism attribution. This study develops an evidence-graded, field-constrained workflow for screening drawdown-driven sand response, scenario-based screen impairment, and potential casing-integrity consequences in a dual-tubing, packerless gas-lift well. The workflow supports surveillance prioritization pending calibration with downhole pressure, screen differential pressure, intervention outcomes, and caliper data.

Keywords: gas-lift well; drawdown; sand production; screen plugging; weak consolidated sandstone; well integrity; production sustainability.

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1. Introduction. In mature oil wells completed in weakly consolidated sandstone reservoirs sand production is a major operational problem [1, 2, 3]. Grain-size distribution influences both the mobilization of formation solids and the retention performance of sand-control screens [4,5]. Laboratory and modeling researches relate sanding onset to the evolving near-wellbore effective-stress state and the mechanical strength of the formation [6,7]. Reservoir depletion, high water cut, and artificial-lift operation can alter effective stress, solids transport, and flowing-pressure conditions. When the drawdown between reservoir pressure and flowing bottom hole pressure reaches the formation-failure condition, grains may detach from the rock matrix and enter the wellbore with the produced fluid [2,6,7].

Gas-lift injection reduces the hydrostatic contribution of the produced-fluid column and changes the flowing-pressure profile of the well [8]. In dual-string gas-lift systems, the distribution of injected gas between the available flow paths can further influence production and pressure behavior [9]. If these changes reduce the flowing bottomhole pressure while reservoir pressure remains comparable, the resulting drawdown increases. In weakly consolidated sandstone, increasing drawdown may move the near-wellbore stress state toward the sanding-failure condition [2,6,7]. Gas-lift adjustment can therefore improve lifting performance while reducing the available drawdown margin; however, the operating change alone does not confirm sand influx or screen impairment.

Dual-tubing gas-lift completions contain interacting tubing and annular flow paths, and the allocation of injected gas between these paths affects lift performance and production response [9]. Field experience with high-rate gravel-packed wells shows that sand-control completion performance should be assessed together with the corresponding production response [10]. In gas-lift wells, abnormal pressure behavior and operational complications can be screened using wellhead data [11], while statistical monitoring and choke-response signatures provide additional surveillance indicators [12,13]. These surface observations are useful for diagnosis, but they cannot independently locate solids accumulation or confirm screen plugging.

Formation instability and screen plugging are related but mechanically distinct phenomena. Near-wellbore formation instability involves grain debonding, displacement, or shear when the local effective-stress state reaches the formation-failure condition [2,6,7]. Screen plugging is a hydraulic

and completion response in which transported grains or fines accumulate on or within the screen medium, reducing its effective flow area [14,15,16]. Neither formation instability nor screen plugging alone demonstrates that casing deformation has occurred.

A reduction in effective screen area redistributes flow through the remaining openings and may increase local velocity and pressure loss [14,15,16]. Studies of sand-control screen erosion show that concentrated sand-laden flow can increase erosion susceptibility under unfavorable velocity and particle-loading conditions [17,18]. However, these studies address screen erosion and do not provide direct evidence of casing deformation in the investigated well.

Casing deformation is a separate structural response that may result from non-uniform external loading, formation displacement, or loss of radial support [19,20,21].

Analysis of operating curves can provide indirect diagnostics of casing-deformation risk [22], but the confirmation of a geometric change requires direct downhole measurement. Because multifinger-caliper, downhole-imaging, and drift or passage records were unavailable, this study reports a predicted casing integrity concern rather than observed casing deformation.

Previous research has examined sand-production mechanisms and prediction [1,2,23], screen selection and clogging [14,15,16], screen erosion [17,18], and casing integrity [19,20,21,22] as largely separate topics. However, fewer studies integrate gas-lift-induced pressure changes, observed sand response, scenario-based screen impairment, and conditional casing-integrity concern within a single field-surveillance workflow.

Accordingly, this study develops an evidence-graded, field-constrained workflow that integrates pressure–production behavior and surface sand response with a geomechanical drawdown framework, scenario-defined reductions in effective screen area, and a conditional casing-integrity pathway. Changes in surface pressure, liquid rate, gas-injection rate, and sand concentration are evaluated separately from the scenario-based hydraulic response to declining effective screen area.

2. Materials and methods. The methodology comprises four linked components: definition of the field case and evidence hierarchy, interpretation of gas-lift pressure–production behavior, geomechanical screening of sanding tendency, and separate evaluation of field-response indicators and scenario-based screen impairment. It is applied to an anonymized dual-tubing, packerless gas-lift well completed in weakly consolidated Balakhany sandstone. The six records represent selected stages from one operating sequence; all disclosed values were anonymized and rounded.

To preserve the hierarchy of evidence, all inputs are classified as field-recorded, calculated, or scenario-defined. Field-recorded variables include wellhead pressure, P_{WH} ; inter-tubing pressure, P_{IT} ; casing-annulus pressure, P_{cp} ; gas-injection rate, g ; liquid production rate, $Q_{l,m}$; and wellhead sand concentration, C_s . Completion geometry and the reported gas-lift configuration are treated as field inputs. Stage-specific reservoir pressure, P_{res} ; flowing bottomhole pressure, P_{wf} ; effective open-area ratio, λ ; differential pressure across the screen, ΔP_{scr} ; and casing deformation were not measured directly. Consequently, drawdown is retained as a geomechanical screening variable, λ is prescribed in the sensitivity analysis, and casing deformation remains an unverified integrity concern rather than a calculated field outcome.

Representative Dual-Tubing Gas-Lift Completion. The investigated completion represents mature offshore dual-tubing, packerless gas-lift well completed in a weakly consolidated sandstone interval. The well configuration reflects mature offshore production conditions where sand influx, high water cut, and unstable gas-lift performance occur at the same time.

The completion comprises a $9^{5/8}$ in production casing and two concentric tubing strings. The $2^{7/8}$ in inner tubing and the $4^{1/2}$ in outer tubing terminate at 2450 and 1800 m MD, respectively. The producing interval extends from 2480 to 2520 m MD and consists of an uncemented open-hole section equipped with a premium-mesh standalone screen; the total measured depth is 2520 m. No packer isolates the annular flow path between the production casing and the tubing strings. Figure 1 presents the conceptual pressure–flow configuration; the schematic is not drawn to scale.

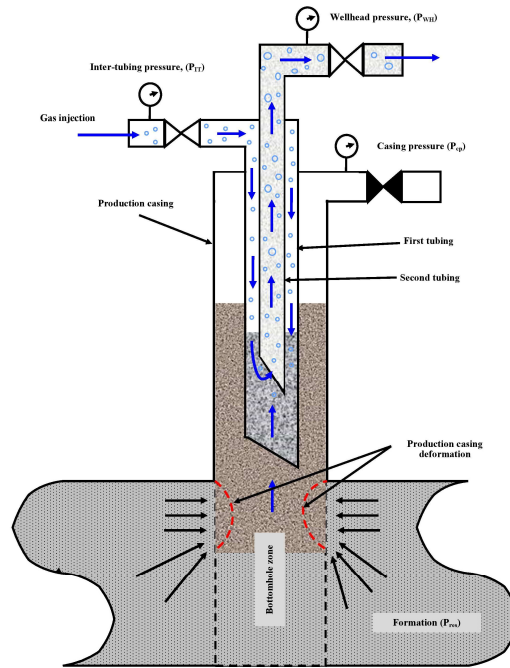


Figure 1. Conceptual pressure-flow configuration of the dual-tubing, packerless gas-lift system, and the hypothesized casing-integrity pathway

Gas is injected through the annular flow path between the 9^{5/8} in casing and the 4^{1/2} in outer tubing. The injected gas moves downward through this annular space and enters the production flow path at depth. The gas then mixes with the produced liquid and reduces the average density of the fluid column. This reduction lowers the flowing bottomhole pressure and supports the upward movement of the gas-liquid mixture through the lift tubing.

The well is completed across the producing sandstone with a standalone premium mesh screen. The screen interval length is 40 m, and the initial open area is 5.5%. The screen is assumed to provide distributed inflow under clean conditions. During sand production, part of the screen surface becomes impaired by retained grains, compacted solids, and fines migration. This reduces the effective open area and changes the inflow pattern from distributed to localized. The field-constrained completion, reservoir, and reference-fluid inputs are summarized in Table 1, together with the evidentiary basis of each value.

Table 1. Field-constrained completion, reservoir, and reference-fluid inputs used in the screening workflow

Parameter	Value	Status or Basis
Well type	Dual-tubing, packerless gas-lift well	Field record
Production casing	9 ^{5/8} in, 47.0 lb/ft; N80/P110 designation	Field record; exact depthwise grade schedule unavailable
Inner lift tubing	2 ^{7/8} in, 6.5 lb/ft; J55/N80 EUE	Field record; exact grade unavailable
Outer lift tubing	4 ^{1/2} in, 12.6 lb/ft; J55/N80 BUE	Field record; exact grade unavailable
Inner tubing depth	2450 m MD	Field record
Outer tubing depth	1800 m MD	Field record
Packer condition	No packer in the active completion	Field record

Producing interval	2480–2520 m MD; open-hole	Field record
Production-casing shoe depth	Not available	No assumed field value assigned
Open-hole diameter	Not available	No assumed field value assigned
Screen type	Premium-mesh standalone screen	Field record
Initial screen open area	5.5%	Design specification
Screen material	316 L stainless steel	Completion description
Nominal screen aperture	Not available for the case screen	A provisional 0.100–0.150 mm range is examined only in sensitivity analysis
Formation	Weakly consolidated Balakhany sandstone	Field description
Porosity	33.5%	Field-constrained reservoir input
Permeability	850 mD	Field-constrained reservoir input
Sand-grain density	2660 kg/m ³	Engineering input
Reservoir-pressure range	16.5–28.0 MPa	Field operating range; not available by individual stage
Flowing bottomhole-pressure range	12.0–15.0 MPa	Calculated operating range; not available by individual stage
Reservoir-temperature range	70–85 °C	Field operating range
Water cut	80–92%	Field operating range
Oil density	840 kg/m ³	Reference value at 25 °C and standard pressure
Formation-water density	1004 kg/m ³	Reference value at 25 °C and standard pressure
Reference liquid-mixture density	971–991 kg/m ³	Calculated from phase densities over the 80–92% water-cut range
Oil viscosity	3.5 cP	Reference value at 25 °C and standard pressure
Formation-water viscosity	1.03 cP	Reference value at 25 °C and standard pressure
Injected-gas relative density	0.65, air = 1	Field-constrained gas-property input
Standard gas conditions	101.325 kPa and 15.56 °C	Reference conditions for reported gas rate
Median formation-grain size, d ₅₀	Not available for the case well	A non-regional value of 0.209 mm is used only as a literature-based sensitivity input [24]
Uniformity coefficient, U _c	Not available for the case well	U _c = 5.0 is used only in the same non-regional sensitivity case [24]

Because case-specific particle-size-distribution data and the manufacturer-certified screen aperture were unavailable, plugging plausibility was examined through a non-regional sensitivity case rather than a reconstructed field measurement. The sensitivity case uses $d_{50} = 0.209$ mm and a uniformity coefficient $U_c = d_{60}/d_{10} = 5.0$ from Reference [24], together with a provisional screen-aperture range of 0.100–0.150 mm. The resulting aperture-to-median-grain-size ratio is 0.48–0.72. This range places the assumed aperture below the median grain size, whereas $U_c = 5.0$ represents a relatively broad particle-size distribution in which finer particles may penetrate and accumulate within the screen medium even when coarser grains are retained. Because screen performance also depends on

the complete PSD curve, fines and clay content, mesh architecture, and flow conditions, this sensitivity case supports the physical plausibility of partial impairment but does not validate the selection or actual plugging state of the case-well screen [4,16].

Gas-Lift-Induced Drawdown Mechanism. At time t , drawdown, $\Delta P(t)$, is defined as the difference between reservoir pressure, $P_{res}(t)$, and flowing bottomhole pressure, $P_{wf}(t)$. Stage-specific P_{res} and P_{wf} measurements were unavailable for the six-stage field sequence; consequently, drawdown was treated as a model-based geomechanical screening variable rather than a directly observed stage parameter.

An increase in gas fraction reduces ρ_m and lowers P_{wf} . This improves lifting performance, but it also increases drawdown across the producing interval. In weakly consolidated sandstone, this effect narrows the safe operating window because excessive drawdown increases the probability of sanding [8, **Error! Reference source not found.**]. In gas-lift operation, injected gas reduces the average density and hydrostatic head of the produced-fluid column. For mechanistic interpretation, the local mixture density is represented by $\rho_m = \alpha_l \rho_l + \alpha_g \rho_g$, where $\alpha_l + \alpha_g = 1$, ρ_l and ρ_g denote the liquid-and gas-phase densities, and α_l and α_g denote their local volumetric fractions. The injected-gas relative density and the reference liquid-phase density and viscosity values used in the screening calculations are reported in Table 1.

This mixture relation is not treated as a depth-resolved multiphase PVT model. Gas density, phase holdup, formation-volume factors, and effective mixture viscosity vary with pressure, temperature, and flow regime, whereas stage-specific downhole pressure-temperature data and detailed injected-gas composition were unavailable. Consequently, the relation is used to explain the expected direction of the flowing-bottomhole-pressure response rather than to calculate stage-specific P_{wf} values. An increase in gas holdup may reduce P_{wf} and enlarge drawdown, but the magnitude of this response also depends on tubing-annulus interaction and the prevailing multiphase-flow regime [8, **Error! Reference source not found.**].

Screen Impairment and Local Inflow Response. Within the screening framework, the near-screen filtration response is interpreted using a Darcy-type relation consistent with coupled hydrodynamic–geomechanical sand-production modelling [23]. For otherwise comparable permeability and fluid properties, an increasing pressure gradient raises the superficial filtration velocity. Because the investigated well produces multiphase fluid and no direct near-screen velocity measurements were available, this relation is used only to establish the expected response direction rather than to calculate a stage-specific filtration velocity.

For operating stage t , the remaining effective screen area is represented as

$$A_{eff}(t) = \lambda(t)A_0, \quad 0 < \lambda(t) \leq 1 \quad (1)$$

where A_0 is the active open area under the reference scenario, and $\lambda(t)$ is the prescribed effective-open-area ratio. A value of $\lambda = 1$ represents the reference condition, whereas $100[1 - \lambda(t)]\%$ represents the assumed loss of effective open area. The stage-specific λ values were selected through production matching to represent progressively restrictive sensitivity cases. However, because no screen inspection, screen differential pressure record, cleanout-volume reconciliation, or manufacturer-specific resistance calibration was available, the matching is non-unique and λ is not treated as a measured or uniquely inferred plugging fraction. Its role is limited to testing how a prescribed reduction in active flow area would affect the normalized local-inflow response.

The liquid rates in the field sequence are reported as mass rates in t/d and cannot be inserted directly into a velocity expression. The corresponding volumetric rate is calculated as

$$q_l(t) = \frac{1000Q_{l,m}(t)}{86400\rho_{l,ref}} \quad (2)$$

where $Q_{l,m}(t)$ is the reported liquid mass rate in t/d, $q_l(t)$ is the volumetric liquid rate in m³/s, and $\rho_{l,ref}$ is the reference liquid-mixture density. Because stage-specific liquid densities were unavailable, a common reference value of 981 kg/m³, corresponding to the midpoint of the 971–991 kg/m³ range in Table 1, is applied to all stages.

The local velocity through the remaining active screen area is then expressed as

$$v_{loc}(t) = \frac{q_l(t)}{\lambda(t)A_0} \quad (3)$$

The screen outside diameter and base-pipe dimensions were unavailable; therefore, A_0 and the absolute value of v_{loc} cannot be determined uniquely for the case well. The field-stage analysis consequently uses the normalized local velocity ratio

$$I_v(t) = \frac{v_{loc}(t)}{v_{loc,0}} = \frac{q_l(t)}{q_{l,0}} \frac{\lambda_0}{\lambda(t)} \quad (4)$$

where subscript 0 denotes the stable reference stage and $\lambda_0 = 1$. Because the same reference density is used for all stages, $\frac{q_l(t)}{q_{l,0}}$ is equal to $\frac{Q_{l,m}(t)}{Q_{l,m,0}}$. Thus, the stage-specific velocity ratio accounts for both the observed change in liquid rate and the scenario-defined reduction in effective screen area.

For a constant total liquid rate, the expression reduces to $I_v = \frac{1}{\lambda}$; this limiting case is presented in Figure 2 only as a generic sensitivity illustration. For the field sequence, the observed liquid-rate ratio is retained. Local inflow acceleration occurs only when the fractional reduction in effective screen area exceeds the fractional decline in total liquid rate. Screen-erosion studies identify local velocity and particle loading as important controls on erosion susceptibility [17,18]. Accordingly, under otherwise unchanged fluid and opening conditions, the present sensitivity analysis represents wall-shear tendency as scaling approximately with I_v and the inertia-related dynamic-stress tendency as scaling approximately with I_v^2 . These are relative scenario indicators rather than absolute stress predictions because opening geometry and depth-resolved mixture rheology were unavailable.

The constant-rate sensitivity of normalized local velocity to effective open-area reduction is illustrated in Figure 2.

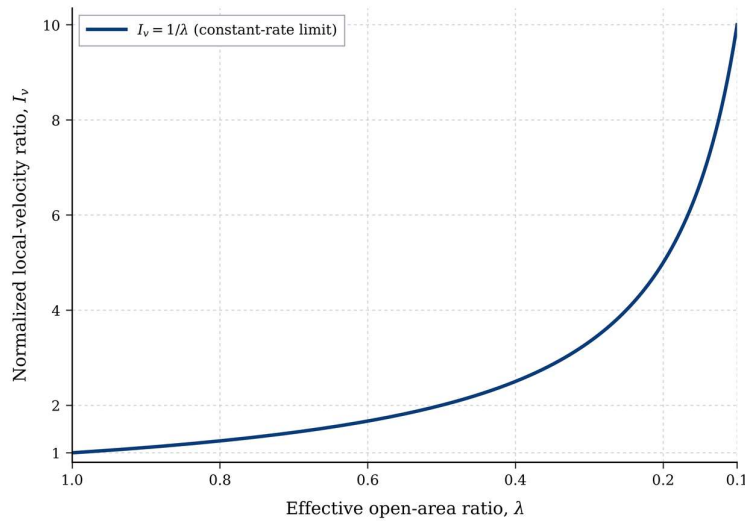


Figure 2. Constant-rate sensitivity of the normalized local velocity ratio to the prescribed effective open-area ratio

The curve represents $I_v = \frac{1}{\lambda}$ for $\frac{q_l}{q_{l,0}} = 1$ and is not a calibrated plugging threshold; the field-stage values reported in Table 2 additionally account for the observed changes in liquid rate.

Table 2. Stage-constrained effective-open-area sensitivity and normalized hydraulic response

Stage	$Q/Q_{1,0}$	Representative λ	Assumed Effective-Area Loss Relative to the Reference, $100(1 - \lambda)$, %	I_v	Normalized Screen-Pressure-Drop Tendency, $I_{\Delta P}$	Interpretation
1	1.000	1.00	0	1.00	1.00	Reference-area scenario
2	0.973	0.95	5	1.02	1.02–1.05	Minor impairment sensitivity
3	0.883	0.75	25	1.18	1.18–1.39	Moderate impairment sensitivity
4	0.500	0.25	75	2.00	2.00–4.00	Partial impairment sensitivity
5	0.333	0.10	90	3.33	3.33–11.11	Severe impairment sensitivity
6	0.000	n/a	n/a	n/a	n/a	Shut-in; hydraulic ratio not evaluated

Casing-Deformation Risk. The casing-integrity pathway considered in this study is conditional. Gas-lift operation may reduce P_{wf} and increase drawdown; if the near-wellbore stress state reaches the formation-failure condition, grain detachment and solids mobilization may occur [2,23]. Because stage-specific downhole pressures were unavailable, the investigated field sequence does not establish that the critical drawdown was actually exceeded.

Mobilized grains and fines may be transported toward the completion, where they can accumulate on or within the screen medium or contribute to screen erosion [14,15,16]. If the effective screen area decreases, the scenario model in Section 2.1.3 predicts redistribution of flow through the remaining openings and possible local velocity amplification. However, screen plugging, erosion, and near-wellbore void development were not directly measured in the case well. They are therefore treated as intermediate scenario-based or inferred steps rather than confirmed field events.

Previous casing-integrity studies identify non-uniform external loading, formation displacement, and loss of radial support as possible contributors to restriction, ovalization, local bending, and intervention-access problems [19,22]. The investigated well had no multifinger-caliper log, downhole image, restriction-depth survey, or drift and passage record. Accordingly, casing deformation is retained only as an unverified integrity concern at the end of the conditional pathway and is not reported as an observed outcome.

Geomechanical Sanding Criterion and Critical Drawdown Model. The hydrodynamic mechanism described in Section 2 explains how gas-lift operation reduces flowing bottomhole pressure, increases drawdown, and accelerates local inflow through the remaining open screen area during partial plugging. However, hydrodynamic acceleration alone does not fully explain sanding onset. Sand production starts when the near-wellbore stress state exceeds the mechanical strength of the weakly consolidated sandstone.

For this reason, the hydrodynamic model is coupled with a geomechanical sanding criterion. The geomechanical part of the workflow evaluates whether the drawdown imposed by gas-lift operation exceeds the critical drawdown pressure of the formation. If this limit is exceeded, the near-screen sandstone becomes unstable, and grains detach from the rock matrix.

The studied interval is represented by weakly consolidated Balakhany sandstone. The mechanical response of this formation is controlled by low compressive strength, limited cohesion, high

porosity, and sensitivity to depletion-induced effective stress increase. The geomechanical model therefore uses effective stress, Mohr–Coulomb failure, and critical drawdown concepts to define the onset of sanding [23].

Effective Stress Around the Producing Interval. Within Biot’s poroelastic framework, the effective stress carried by the rock skeleton is related to the total stress and pore pressure as follows [25]:

$$\sigma' = \sigma - \alpha P_p \quad (5)$$

where σ' is effective stress, σ is total stress, α is Biot coefficient, and P_p is pore pressure.

For the producing interval, this relation is applied to the vertical and horizontal stress components. As reservoir pressure declines during depletion, pore pressure decreases and effective stress increases around the near-wellbore zone. This effect is important in mature weakly consolidated sandstone because it reduces the safe drawdown margin and increases the probability of sanding.

Mohr–Coulomb Sanding Criterion

The Mohr–Coulomb failure criterion is used to evaluate shear failure in the weakly consolidated sandstone:

$$\tau = c + \sigma'_n \tan \varphi \quad (6)$$

where τ is shear stress, c is cohesion, σ'_n is effective normal stress, and φ is internal friction angle.

In terms of principal effective stresses, the failure condition may be expressed through a Mohr–Coulomb failure function:

$$F_{MC} = (\sigma'_1 - \sigma'_3) - (\sigma'_1 + \sigma'_3) \sin \varphi - 2c \cos \varphi \quad (7)$$

where σ'_1 is maximum principal effective stress, and σ'_3 is minimum principal effective stress. The formation remains stable when F_{MC} is below the failure limit. Sanding onset is expected when the operating drawdown increases the near-wellbore stress state to this limit [26,27].

Representative Geomechanical Inputs and Data Provenance. The representative geomechanical inputs were obtained from an existing one-dimensional mechanical-earth-model (MEM) database for the target interval rather than from new laboratory testing. Table 3 identifies the derivation basis and data-availability status of each parameter. The underlying raw logs, core-calibration records, test results, measurement counts, and statistical distributions were not available in the disclosed dataset.

Table 3. Representative geomechanical inputs and their derivation status for the 2480–2520 m MD interval

Parameter	Symbol	Representative Value	Derivation Basis in the Source MEM	Range and Measurement-Count Status
Unconfined compressive strength	UCS	14.44 MPa	Sonic-log-derived representative input	Raw sonic samples, calibration records, n, and min–max range unavailable
Cohesion	c	4.05 MPa	Calculated from representative UCS and friction angle using the Mohr–Coulomb relation	Derived quantity; independent n and measured range not applicable
Internal friction angle	φ	31.5°	Log-derived representative input in the source MEM	Underlying correlation record, n, and min–max range unavailable

Static Young's modulus	E	2.40 GPa	Static-equivalent input converted from dynamic elastic response	Dynamic-to-static calibration dataset and range unavailable
Poisson's ratio	ν	0.28	Derived from compressional- and shear-wave response	Raw V_p/V_s samples, n, and range unavailable
Biot coefficient	α	0.78	Calculated poroelastic input based on static and grain bulk moduli	Underlying modulus values and propagated uncertainty unavailable
Vertical stress	σ_v	54.8 MPa	Representative source-MEM value based on bulk-density integration	Density-log integration record and uncertainty range unavailable
Maximum horizontal stress	σ_H	47.8 MPa	Model-derived representative horizontal-stress input	Calibration observations and uncertainty range unavailable
Minimum horizontal stress	σ_h	41.2 MPa	Field-constrained representative source-MEM input	Underlying LOT/mini-frac record, n, and uncertainty range unavailable

The values in Table 2 are deterministic screening inputs and should not be interpreted as sample means, measured min–max intervals, or statistically calibrated distributions. Cohesion was calculated from the representative UCS and friction angle as $c = \text{UCS}(1 - \sin\phi)/(2\cos\phi)$, which gives approximately 4.05 MPa. The reported stresses indicate a normal-faulting ordering, $\sigma_v > \sigma_H > \sigma_h$. As the source calibration files and uncertainty distributions could not be obtained, the classification of geomechanics and well casing integrity is conditional upon this representative set of parameters.

The stress regime is important for the depleted sandstone because a decrease in pressure causes an increase in effective stresses in this zone.

Critical Drawdown Definition and Calibration Requirement. Critical drawdown is the difference between reservoir pressure and the critical flowing bottomhole pressure at which the selected formation-failure criterion is first satisfied. Critical-drawdown prediction has been addressed using analytical and field-case methods [28,29], weak-sandstone and perforated-well models [30,31], and one-dimensional geomechanical or reservoir-specific numerical models [32,33,34]. These studies show that the critical value depends on formation strength, in situ stress, completion geometry, pressure conditions, and the selected failure criterion; it is therefore a well-specific parameter rather than a universal pressure limit.

For a well with the required pressure and geomechanical data, critical drawdown is defined as

$$P_{\text{res}}(t) - P_{\text{cwf}}(t) \quad (3)$$

where P_{cwf} is the critical flowing bottomhole pressure predicted from the calibrated formation-failure model. Proximity to this limit can then be expressed through

$$I_D(t) = \frac{\Delta P(t)}{\Delta P_{\text{crit}}(t)} \quad (4)$$

Operation at $I_D < 1.00$ remains below the modelled sanding threshold, whereas $I_D \geq 1.00$ indicates that the calibrated threshold has been reached or exceeded. No additional numerical warning boundary is assigned because a lower limit, such as 0.80, has not been established from statistical validation or documented intervention outcomes.

Stage-specific P_{res} , P_{wf} , and calibrated P_{cwf} values were unavailable for the six-stage field sequence. Consequently, I_D is retained as a future field-calibration variable and is not reported as a calculated stage-level result in the present case. Reaching the critical-drawdown condition would indicate an increased sanding tendency; it would not independently confirm screen plugging or casing deformation.

Conditional Coupling Between Sanding and Inferred Screen Impairment. The solids arriving at the wellhead are measured directly from the field as sand concentration at wellhead, C_s , but there is not unique interpretation that this C_s represents solely a near-wellbore mechanical failure event; C_s may represent a new grain detachment, accumulation remobilization, variable transport intermittency, or a shift in liquid carrying capacity [31,32]. Hence the continuous increase of C_s from stage to stage is used here as an operator marker of instability rather than the individual occurrence confirming exceeding of Mohr–Coulomb failure limit.

The proposed coupling is conditional: drawdown-induced near-wellbore instability may mobilize formation grains, while transported grains and fines may subsequently accumulate on or within the screen medium and reduce its effective open area [14,16]. However, the surface sand concentration, C_s , cannot by itself confirm the presence, location, or severity of screen plugging. Accordingly, the operating stages described are not used to impose a one-to-one relationship between C_s and screen plugging; instead, they provide field constraints for the scenario-based hydraulic sensitivity analysis presented later in the manuscript.

For the field data, Stage 1 is used to represent initial stable operations, Stages 2–3 are designated as increasing sand production, and Stages 4–5 as consistent with screen plugging since both liquid rate-loss and wellhead surface pressure changes accompany increasing sand rates. The above designations are interpretations of observed operations and cannot prove the physical location, thickness, or internal configuration of any screen plug [35,36].

The conditional link between mechanics and hydraulics provides the conceptual basis for the two-axis screening framework developed in Section 4.

Field Case and Input Data. Case-Study Basis. The proposed workflow is applied to an anonymized single-well field case from a mature offshore dual-tubing, packerless gas-lift well completed in a weakly consolidated sandstone reservoir in the South Caspian Basin. The case reflects real operating behavior observed under high water cut, declining reservoir pressure, sand influx, screen impairment, and unstable pressure response.

The case is derived from confidential operational records of one monitored offshore gas-lift well. For confidentiality reasons, the well name, exact field identifier, coordinates, full raw time-series records, and intervention files are not disclosed. Instead, the pressure–production sequence, sand-concentration response, completion geometry, and geomechanical inputs are reported in anonymized, rounded, and engineering-interpretable form. This allows the diagnostic workflow to be tested on real field behavior while protecting operationally sensitive information.

The representative well configuration, completion geometry, and geomechanical inputs were defined in Sections 2 and 3. This section adds the pressure–production sequence used to test the model response during the transition from stable gas-lift production to sand-loaded flow, partial screen plugging, and predicted casing-deformation risk.

Operating-Stage Definitions. The field sequence is divided into six diagnostic stages to organize the observed pressure, production, and sand-concentration changes. These labels are interpretive and do not represent independently verified downhole conditions. Stage 1 defines the stable reference condition; Stage 2 represents an early transition; Stage 3 represents excited sanding; Stages 4 and 5 represent partial and severe impairment scenarios, respectively; and Stage 6 represents the shut-in or pre-intervention condition.

The Stage 2 label does not assert that drawdown was measured to increase because concurrent P_{res} and P_{wf} values were unavailable. Likewise, the Stage 4 and Stage 5 labels describe conditions consistent with progressive flow-path impairment under the assigned λ scenarios rather than screen states confirmed by inspection. The stage definitions are based on the combined evolution of liquid rate, wellhead sand concentration, and surface-pressure response.

Stage 1 serves as the stable reference. Stage 2 captures an early departure from that reference, whereas Stage 3 is identified by a measurable increase in wellhead sand concentration accompanied by a comparatively limited decline in liquid production. Stages 4 and 5 are evaluated as partial and severe impairment scenarios, respectively, because the corresponding downhole screen conditions

were not directly measured. Stage 6 represents the shut-in or pre-intervention condition and is retained for operational context but excluded from the field-response-score calculation for the five flowing stages.

3. Results and discussion. The contrast between production decline and the sand-concentration multiplier is illustrated in Figure 3.

Figure 3 shows that the sand-concentration response becomes pronounced before the largest production loss. At Stage 3, the sand multiplier reaches 15, while the liquid-rate decline remains 11.7%. At Stages 4 and 5, the sand multiplier increases to 80 and 150, respectively, while the corresponding production declines reach 50.0% and 66.7%. These measured field responses are used in the field-response branch, whereas the prescribed λ values and their hydraulic consequences are evaluated separately in Table 4. Their temporal co-variation supports diagnostic prioritization but does not independently confirm physical screen plugging or localized inflow redistribution.

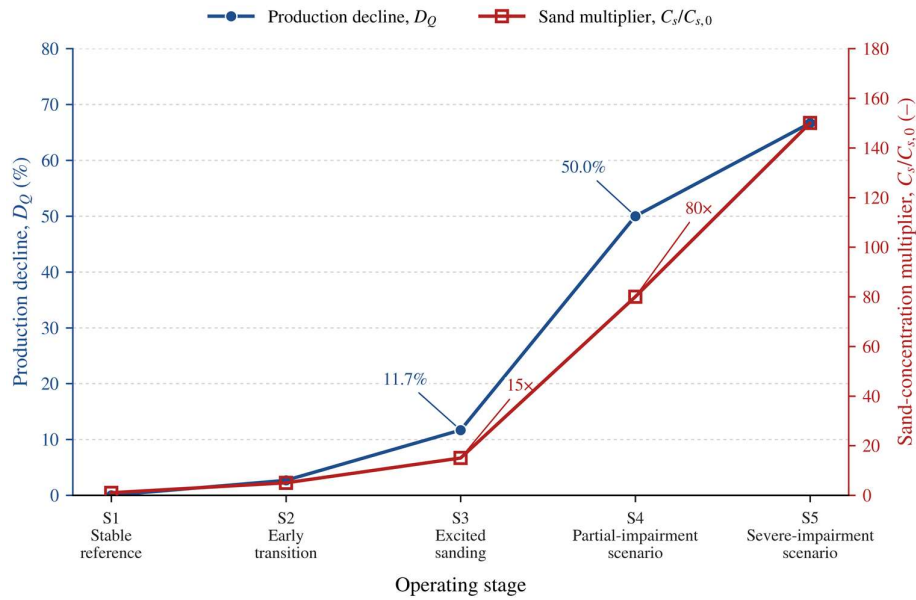


Figure 3. Production decline and sand-concentration multiplier across the five flowing stages.

Connecting lines are visual guides between selected stage-level records and do not represent a continuous or smoothed time series. The labels assigned to Stages 4 and 5 denote prescribed impairment scenarios rather than screen conditions verified by downhole inspection.

Stage-Level Pressure Response. The pressure records reported in Table 3 show an increase from the stable reference to Stage 4. Over this interval, P_{WH} increases from 3.5 to 5.9 MPa, P_{IT} from 4.2 to 6.5 MPa, and P_{cp} from 6.5 to 7.2 MPa. Stage 4 therefore has the largest combined pressure deviation from the reference condition in the evaluated sequence.

At Stage 5, P_{WH} , P_{IT} , and P_{cp} decrease to 3.2, 4.0, and 6.4 MPa, respectively, despite the further reduction in liquid rate and increase in sand concentration. This non-monotonic response indicates a change in the hydraulic state of the production system. The selected records, however, cannot determine whether the change resulted from restriction release, multiphase-holdup redistribution, altered gas-lift hydraulics, or another transient process.

Figure 4 presents the three pressure variables across the five flowing stages. The connecting lines are visual guides between selected stage records and should not be interpreted as a continuous pressure waveform.

Because the underlying high-frequency records are unavailable, the data do not support calculation of oscillation period, pulsation amplitude, or buildup–release cycle frequency. The

pressure decrease at Stage 5 is therefore reported as a non-monotonic stage-level response rather than as confirmed collapse or release of a sand restriction.

Stage 6 represents a shut-in or pre-intervention condition in which both gas injection and liquid production are zero. Its casing-annulus pressure of 7.5 MPa may represent trapped or isolated pressure under non-flowing conditions. Stage 6 is retained for operational context but is excluded from the flowing-stage pressure normalization and field-response-score calculation.

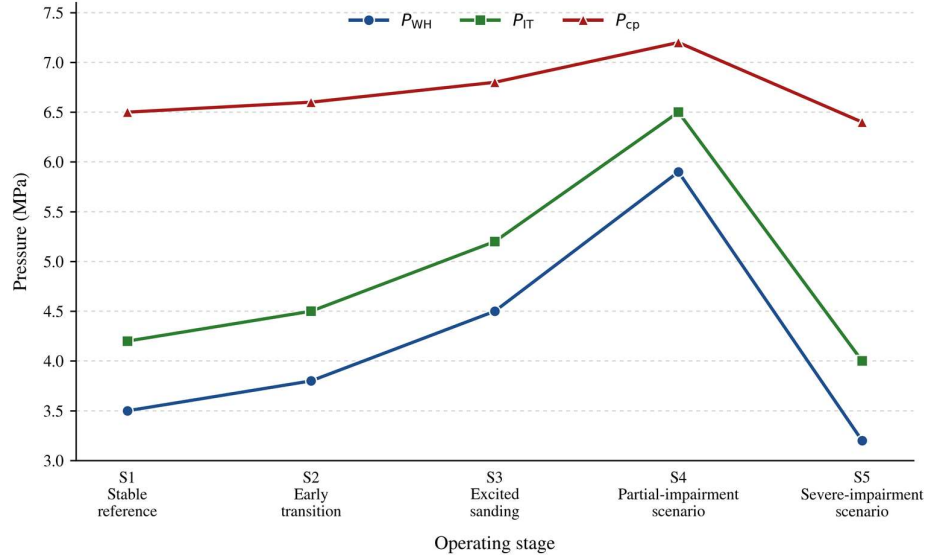


Figure 4. Stage-level wellhead, inter-tubing, and casing-annulus pressures across the five flowing stages.

Connecting lines are visual guides between selected operating records and do not represent a continuous pressure waveform.

Gravel packing may provide more durable sand retention than a standalone screen where formation PSD, fines content, and completion geometry permit effective placement [24]. Screen replacement or redesign should be based on measured PSD and screen-retention testing rather than on the regional sensitivity values used in the present study [16]. Chemical consolidation may be considered where mechanical remediation is impractical, but its use requires laboratory evaluation of retained permeability, consolidation strength, temperature stability, and compatibility with the produced fluids [**Error! Reference source not found.**].

A sustained departure of S_{FR} from the reference stage, when accompanied by persistent sand production or evidence of declining well accessibility, should prompt physical integrity verification before further production optimization. Choke or gas-injection adjustments made without confirming the condition of the flow path may temporarily alter the surface response while leaving a developing restriction unresolved. The selected response should therefore depend on the calibrated I_D ; the persistence of the measured pressure, production, and sand signals; and any direct evidence obtained during cleanout or downhole intervention.

4. Conclusions. This study developed an evidence-graded, field-constrained workflow for recognizing operational deterioration associated with sand production in a dual-tubing, packerless gas-lift well. The field-response score, (S_{FR}), combines normalized liquid-rate loss, surface sand response, and pressure deviation, whereas (λ) and (I_v) are retained as separate scenario-based sensitivity variables. This structure enables comparison of operating stages without treating prescribed impairment scenarios as measurements of the screen condition.

For field operation, drawdown should remain below the calibrated critical drawdown, ($\Delta P < \Delta P_{crit}$), corresponding to ($I_D < 1.00$). An upward trend in (I_D) toward 1.00 should prompt verification

and intensified surveillance, whereas ($I_D \geq 1.00$) should initiate corrective drawdown management through choke and gas-injection review, subject to gas-lift stability constraints. A sustained (S_{FR}) departure accompanied by persistent sand production should prompt screen differential pressure measurement, cleanout-response evaluation, coiled-tubing passage checks, or multifinger-caliper logging. Because stage-specific downhole pressures, measured screen pressure drop, complete PSD statistics, resolved tubular properties, and direct casing-deformation measurements were unavailable, the casing-integrity outcome remains unverified, and the workflow requires multi-well calibration before wider application.

Conflict of interest.

The authors declare that they have no conflict of interest in relation to this research.

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