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Research Article

Application of geomechanical models to predict sand production and propose well completion solutions for Well X in the Hai Thach field

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Abstract: Sand production is a serious problem during oil and gas production in unconsolidated sandstone formations. It can rapidly damage downhole and surface equipment. Therefore, oil and gas contractors constantly seek methods to control sand production. However, in unconsolidated sandstone formations, sand production typically occurs during the later stages of production. Some wells encountered sand production from the beginning stage, while others could be produced without having sand production if managed properly. This indicates that sand production is influenced by both reservoir properties and well production operating conditions. Reservoir properties can be determined during the exploration phase. Additionally, several researchers have demonstrated that sand production mechanisms are linked to these reservoir parameters. In this paper, we employ a geomechanical model to predict the critical reservoir pressure and critical drawdown pressure values leading to sand intrusion and subsequently propose well completion strategies of Expandable Sand Screens to prevent sand production and optimise production performance processes to enhance the efficiency of oil and gas exploitation investments. The accurate assessment of sand occurrence in production process potential enables investors to make mindful decisions regarding sand control measures for specific wells. Sand control is an expensive and risky undertaking; however, it is crucial for wells with high sand production potential to prevent damage to surface equipment and operational complications caused by sand.

Keywords: Geomechanical modeling; Sand intrusion; Pressure; Sand control; Well completion.

1. Introduction

The Hai Thach field is located in block 05-2, the south part of the Nam Con Son basin, on the continental shelf of southern Vietnam. The field is 330 km southeast of Vung Tau city, an oil and gas field in a deep-water area of 134 m. The field produces from miocene unconsolidated sandstone reservoirs (Dong Nai formation, BIII sand), middle miocene (upper and lower Con Son formation, BII.2.20, BII.2.30, and BII.1.10 Sands), lower miocene (upper and lower Bach Ho formation, BI.2.20, BI.2.30, BI.1.20 sands), lower oligocene (lower Tra Tan formation, E.10 and E.20 sands), and pre-tertiary basement. The structural configuration of the Hai Thach gas field includes horseshoe-shaped faults trending north, northeast, and south-southeast (MMH & LMH) and block-type shoulder faults trending east (MMF) located below the main discontinuous unit (MMU). Most faults are truncated at MMU, but a few faults extend and overthrust the UMA unit. Well X drilled on the horseshoe-shaped structure of the Hai Thach field [1, 2]. The cross-sections of some of the gas reservoirs that Well X will penetrate are shown in Figure 1.

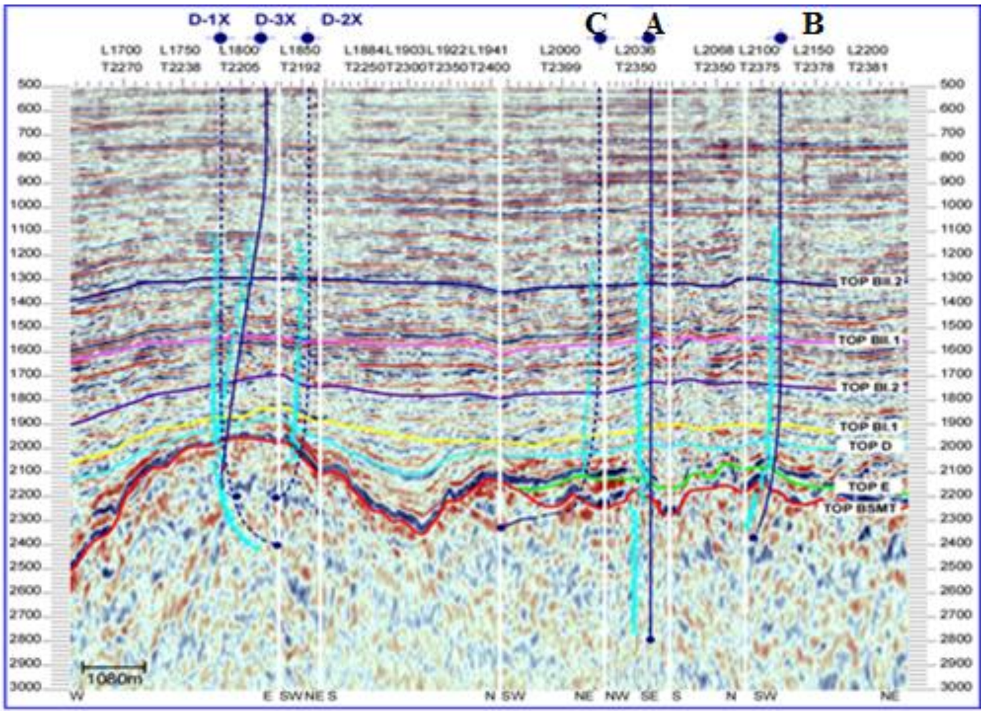

Figure 1. Geological Cross-Sections of the Hai Thach field.

Sand production in the oil and gas production process occurs when a significant number of solid particles detach from the formation. These particles are carried by the fluid flow into the well and to the surface along with the produced hydrocarbons.

These solid particles can be different in composition and size, but they are primarily sand particles with a size range of 0.60 mm to 4.75 mm. When the amount of these solid particles exceeds the allowable limit, sand control measures must be implemented to protect the well, downhole equipment, and ensure safe and efficient production. This allowable limit depends on the equipment, type of sand, reservoir conditions, and company strategy [3]. A common benchmark for comparison is 0.1% of the total produced volume.

The reservoir lithology in the Hai Thach field is mainly weakly consolidated sandstone. Sand production in these reservoirs occurs in two stages. The specific form of sand production varies depending on the characteristics of the reservoir. To effectively control sand production, it is essential to understand the characteristics of the reservoir being produced and select the appropriate treatment method.

2. Materials and methods

2.1. Pressure model

When a well is drilled into a formation, the rock material is displaced upwards. The wellbore wall is only supported by the drilling fluid pressure in the wellbore. If this fluid pressure is not balanced with the in-situ stresses, stress redistribution occurs around the wellbore. This can lead to a total stress greater than the formation's resistance, resulting in failure.

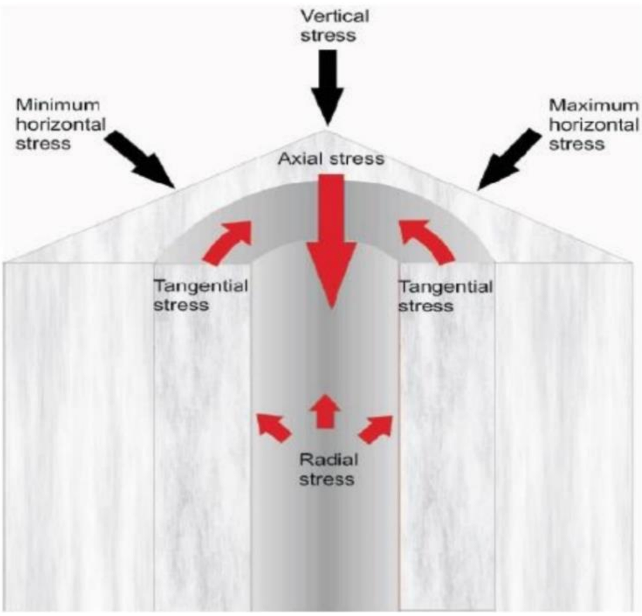

Figure 2. In-situ stress model around a drilled wellbore

The various stresses and pressures include: σ_V is the ertical stress; σ_H is the maximum horizontal stress, σ_h is the minimum horizontal stress; p_f is the drilling fluid pressure in the formation; p_w is the flowing pressure of fluid from the formation into the well; σ_θ is the tangential stress; σ_r is the radial stress; σ_z is an axial stress, typically vertical.

The determination of new stresses around a wellbore involves considering the inclination angle (i) and the azimuth angle (θ). According to reference [21], the new stress values can be calculated using the following formulas:

$$\sigma_x = \sigma_H \cos^2\theta \cos^2 i + \sigma_h \sin^2\theta \cos^2 i + \sigma_v \sin^2 i \quad (1)$$

$$\sigma_y = \sigma_H \sin^2\theta + \sigma_h \cos^2\theta \quad (2)$$

$$\sigma_z = \sigma_H \cos^2\theta \sin^2 i + \sigma_h \sin^2\theta \sin^2 i + \sigma_v \cos^2 i \quad (3)$$

When considering a soil or rock element on the wellbore wall, the stresses are distributed according to a cylindrical coordinate system with coordinates (r, z, θ).

$$\tau_{xy} = \frac{1}{2}(\sigma_H - \sigma_h)\sin 2\theta \cos i \quad (4)$$

$$\tau_{xz} = \frac{1}{2}\sin 2i(\sigma_v - \sigma_H \cos^2\theta - \sigma_h \sin^2\theta) \quad (5)$$

$$\tau_{zy} = \frac{1}{2}(\sigma_H - \sigma_h)\sin 2\theta \cos i \quad (6)$$

When analyzing stress distribution around wellbores, the polar coordinate system is often used to represent the stress components. The stress values for soil or rock elements surrounding the wellbore in polar coordinates are shown in Figure 3.

Wellbore Stability Analysis Using the Fracture-Strain Model for Vertical Well X: The fracture-strain model for vertical wells assumes that the principal stresses are perpendicular to the wellbore axis are shown in Figure 4. This implies that the stresses at the wellbore wall can be represented by:

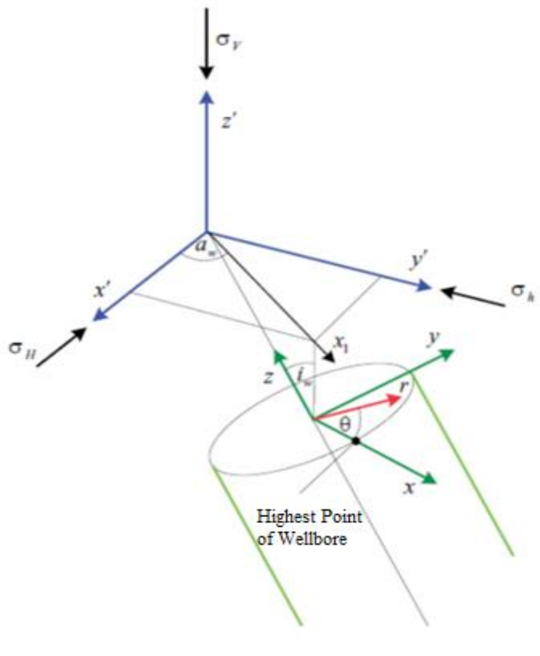

Figure 3. Stress state at the wellbore.

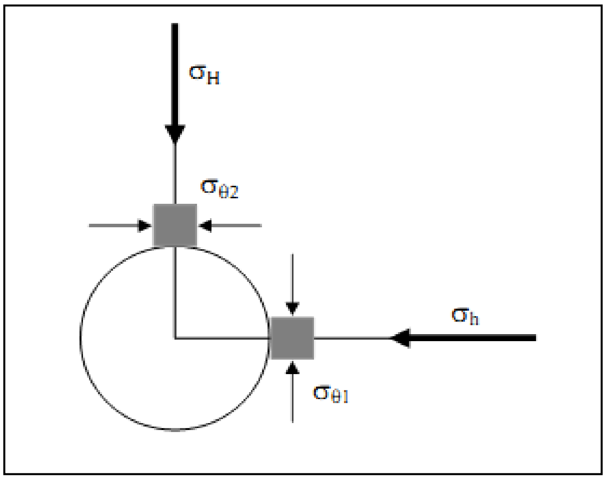

Figure 4. Tangential stress at the wellbore wall [5].

The model is based on the premise that wellbore failure occurs when the tangential stress at the wellbore wall exceeds a certain threshold. While other stress components also contribute to wellbore failure, their effects are considered negligible in this model [6].

To establish a sand production model, it is crucial to identify the time or location at which wellbore failure initiates, leading to sand intrusion. To prevent this phenomenon, the maximum effective tangential stress ($\sigma_{\tau 1}$ - p_w) must be less than the effective strength (U) of the formation. This can be expressed as:

$$\sigma_{\tau 1} - p_w \leq U \tag{7}$$

According to [3], the bottomhole pressure value to prevent sand production is determined as follows:

$$p_w \geq \frac{3\sigma_H - \sigma_h - U}{2 - A} - P_o \frac{A}{2 - A} \tag{8}$$

The critical drawdown pressure (CDP) is defined as the maximum reduction in wellbore pressure from reservoir pressure that can be applied without causing wellbore failure. It can be determined using the following equation:

$$p_w = P_o - CDP \tag{9}$$

Substituting Equation (7) into Equation (8), we obtain:

$$P_o = \frac{1}{2}\left[3\sigma_H - \sigma_h - U + CDP(2 - A)\right] \tag{10}$$

or

$$CDP = \frac{1}{2 - A}\left[2P_o - (3\sigma_H - \sigma_h - U)\right] \tag{11}$$

While the wellbore fracture model presented earlier can be applied to vertical wells, adjustments are necessary for inclined wells due to their non-vertical orientation. These adjustments account for the influence of wellbore inclination on stress distribution and formation failure.

The critical reservoir pressure (CRP) is defined as the reservoir pressure drop corresponding to a CDP of zero. This implies that at this pressure, formation failure can occur under any further pressure reduction. The relationship between CRP and CDP can be expressed as:

$$CRP = \frac{3\sigma_H - \sigma_h - U}{2} \tag{12}$$

The formation strength (U) represents the maximum stress that the formation can withstand before failure. It is typically determined through laboratory experiments on thick-walled cylindrical samples with outer-to-inner diameter ratios ranging from 3 to 3.8. [6–8]. The expression for U is given by:

$$U = 3.1TWC \tag{13}$$

The thick-walled cylinder strength (TWC) can be determined experimentally or through empirical formulas [5]:

$$TWC = 83UCS^{0.5242} \tag{14}$$

The aforementioned formulas and parameters can be incorporated into a computational model to assess the critical reservoir pressure (CRP) and formation failure potential. The model can be implemented using Excel to perform calculations and generate results.

2.2. Data collection and processing

Well X research was carried out in reservoir E20, this is a well with a vertical well completion zone, with coefficient stress change ratio is 0.62 and reservoir has Max. Perforation diameter 1.965inch, bio elastic is 1, depletion is zero percent, The average particle diameter is 300 µm with reservoir data given in Table 1.

Table 1. Input data for well X in reservoir E20 GOC [1].

Well Diameter (in)	True vertical depth (TVD) (m)	Inclination (deg.)	Azimuth (deg.)	Poisson's ratio (MPa)	Pore pressure (deg.)	Unconfined Compressive strength (Psi)	Vertical stress (Psi)	Min Horizontal Stress (Psi)	Max Horizontal stress (Psi)	Mean grain diameter (µm)
12.25	2266	52.7	230.5	0.26	3197	1870	6650	4959	5207	204.8

3. Results and discussion

3.1. Calculate sand generation pressure for well X

By using Microsoft Excel software and using the formulas from (1) to (11), with the data of well X given in Table 1. The study can determine the intermediate parameters of stresses as shown in Table 2.

Table 2. The calculation results of the stress.

σ_x	σ_y	σ_z	τ_{xy}	τ_{xz}	τ_{zy}
6173.61	4900	5626.38	99.34	751.75	141.88

After calculating the stress components, we calculate the intermediate components and the resulting pressure drop is given in Table 3.

Table 3. The calculation results of physical and mechanical components of rock.

A	TWC	U	CRP	CDP	CBHFP
0.67	4222.45	10302.78	1659.03	2536.45	813.54

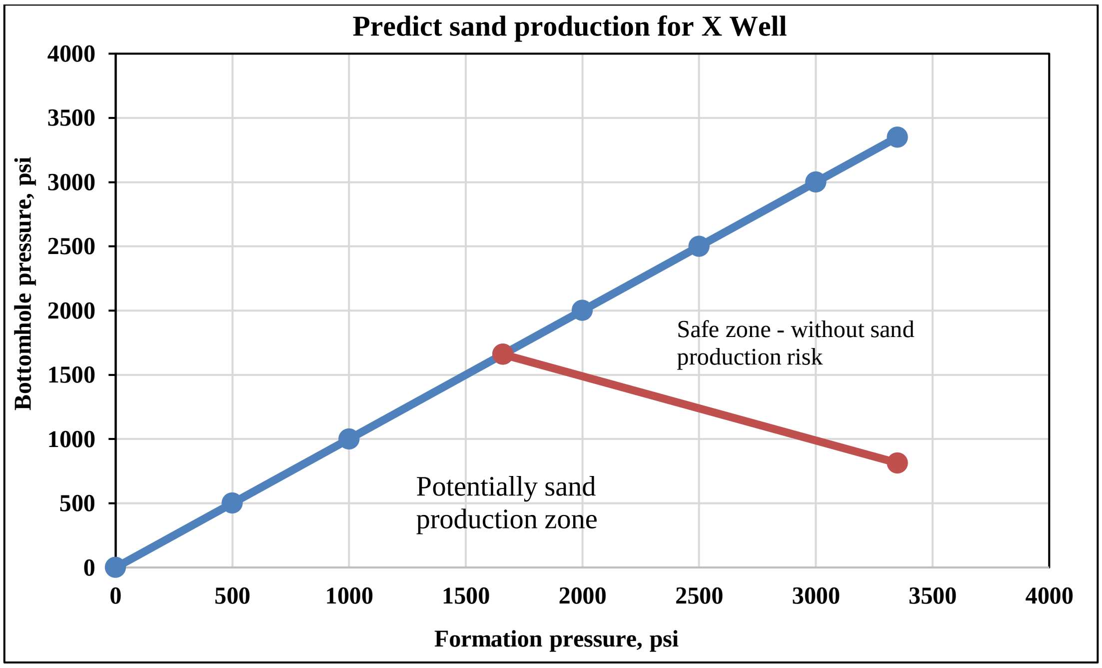

Figure 5. Critical drawdown pressure results for well X.

The presented model is constructed based on data that elucidates the influence of reservoir pressure and drawdown on formation failure. The X-axis represents reservoir pressure, while the Y-axis represents wellbore pressure. A diagonal line (in blue) denotes the positions where reservoir pressure equals wellbore pressure, dividing the graph into two sections. The upper portion represents the scenario of overbalanced drilling and injection, while the area below the line represents the drawdown process during well production. The failure line (safe zone - without sand production risk) is also depicted on the graph. In Figure 5, the failure line (in red) intersects the diagonal line at a pressure of approximately 1659 psi. This represents the threshold below which wellbore pressure should not fall to prevent sand production. This failure line varies depending on the specific rock strength and completion method employed. Rock strength is typically determined by the Unconfined Compressive Strength (UCS) value. The failure line illustrates the pressure conditions under which reservoir and wellbore pressures can cause formation failure. In the presented graph, the region (Safe zone - without sand production risk) encompasses pressure conditions above the failure line, indicating the absence of sand production. Conversely, the area to the left represents the zone where formation failure and potential sand production occur [9–11].

We get the results of the sand production zone pressure, the results for well X are shown in Figure 5. We determine the maximum wellbore decline pressure (Max. Drawdown, CBHFP) is 8.13.54 psi and the maximum decline reservoir pressure (Max. Depletion Rerservoir Pressure) is 3350 psi (Figure 5). Therefore, controlling bottom pressure to maintain reservoir pressure within the threshold of not generating sand will optimize the exploitation process.

3.2. Proposed completion solutions for Well X using gravel-packed screens

The type of screen, screen mesh size, and gravel size (if using gravel packing) should be carefully designed and selected based on the specific characteristics and properties of the formation. Gravel packing design procedure for wells [12]: Particle size analysis based on core samples; gravel selection; screen selection; gravel transport fluid selection; method for placing gravel mixture at the well bottom. This study introduces a method for particle size analysis based on core samples and presents the selection criteria of gravel and screen. After analyzing the grain size distribution of the reservoir sand, the authors selected the gravel packing material and then, based on the screen selection criteria, calculated the screen opening size and selected the Expandable SandScreen.

Currently, there are many types of sand screens available worldwide, such as Expandable Screens, Con-Slot screens, gravel-pack screens, etc. This study focuses on one type of sand screen, the Expandable Screen. This type of sand screen is expandable and can be adjusted in size, making it a new product in this field with significant advantages over previous sand screens. Expandable Screens can replace both conventional and modern sand control techniques due to their superior design: they eliminate the annular space between the wellbore and the screen, maximizing the flow area inside the production tubing and stabilizing the flow within the tubing [13–15].

Expandable Sand Screens (ESS) represent a significant advancement in sand control technology, addressing the issue of sand production by utilizing an expanding screen that fills the annular gap between the wellbore and the formation. This innovative design not only eliminates the need for gravel packing but also provides enhanced formation support. Additionally, the installation of ESS reduces the required casing size during wellbore completion and facilitates easy intervention for adjustments [16].

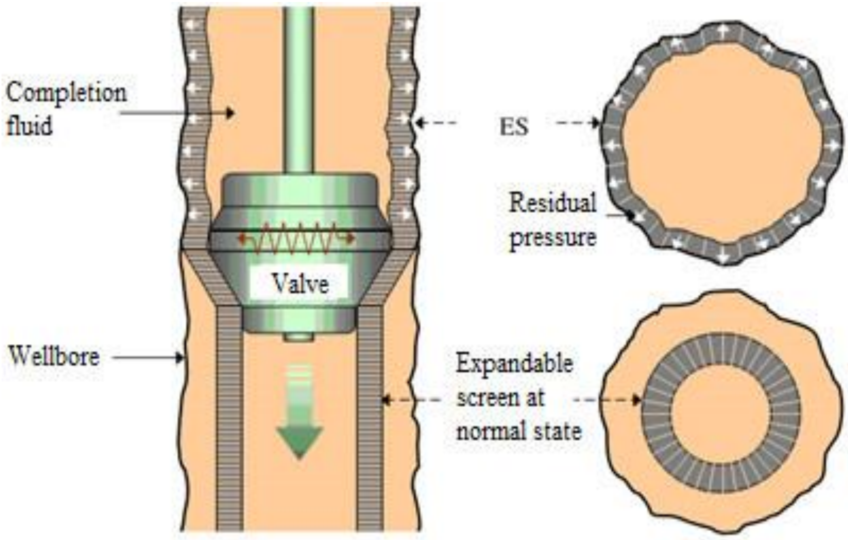

Figure 6. Expandable Screen [14].

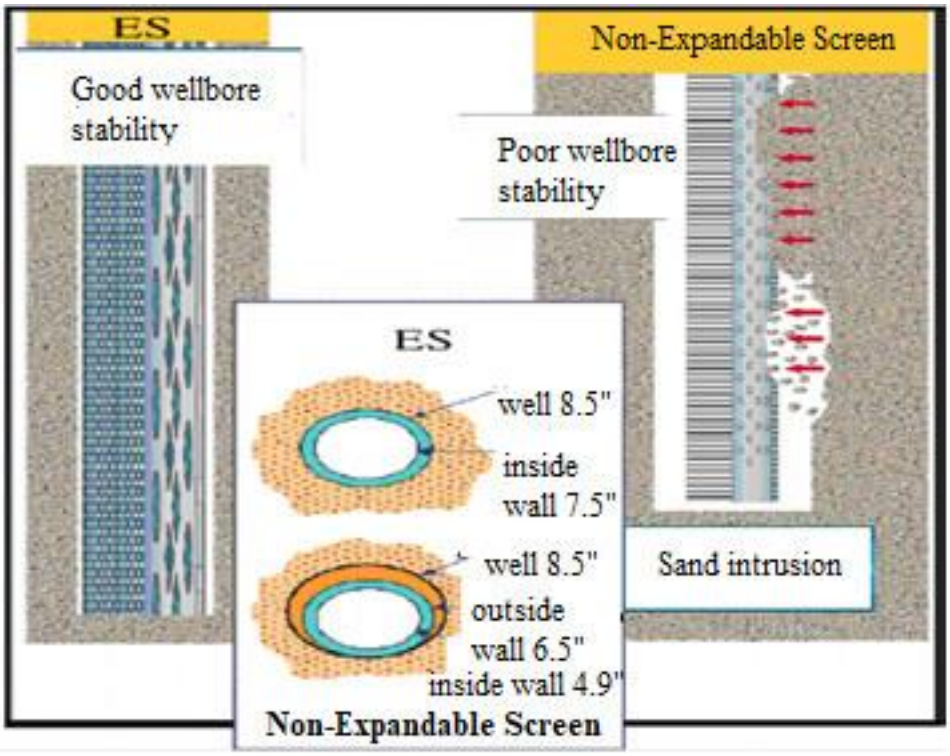

Figure 7. Expandable Screen around annulus [17].

Expandable sand screens (ESS) have revolutionized sand control equipment by eliminating the annular gap between the wellbore and the screen [18]. This innovative design maximizes the flow area within the production tubing, eliminating turbulent flow along the annular space and minimizing erosion of the wellbore. Consequently, ESS contributes to enhanced wellbore stability.

Compared to open-hole completions and gravel packing techniques, ESS offers a more uniform pressure drawdown and a less variable inflow characteristic. These advantages translate into improved production capabilities, particularly in horizontal wells. Additionally, ESS implementation in multilateral wells is significantly simpler compared to conventional sand control methods, which often involve complex installation procedures and are prone to operational issues [19–20].

4. Conclusion

Given the complexities of the oil and gas industry and the ever-increasing demand for energy, the pursuit of optimized sand control methods remains crucial. Sand production, especially in large quantities, can lead to severe consequences, including sand accumulation in wellbores and surface equipment, erosion of both downhole and surface equipment, and formation collapse.

Utilizing geomechanical models to determine sand production pressure serves as a valuable tool in sand management and mitigation strategies. These models enable the identification of sand production thresholds and critical drawdown pressures for the formation. Armed with this information, petroleum engineers and mining technology experts can promptly implement effective reservoir management measures to minimize sand production and optimize reservoir extraction.

For gas wells in the Hai Thach field, expandable screen (gravel-packed screen) sand control methods have been proven suitable for wells experiencing sand intrusion after a period of production. However, their implementation requires:

- Elimination or filling of the annular gap;
- Creation of the smallest possible choke or elimination of sand accumulation;

- Minimize pressure loss during fluid flow;
- Reduction or elimination of gravel bag damage;
- Enhanced formation support.

Author contribution statement: Generating the research idea; statement of the research problem; analysis of research results and data preparation; wrote the draft manuscript: D.L.Q.

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Competing interest statement: The authors declare no conflict of interest.

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