INTRODUCTION

The efficient and commercial development of shale oil reservoirs often relies on the use of horizontal wells and hydraulic fracturing techniques. Successful hydraulic fracturing operations can generate fracture networks for the increase in the contact area with the low permeability matrix. Typically, tightly spaced horizontal wells that are hydraulically fractured are placed in shale oil reservoirs for better production performance. In consequence, the overall fracturing and production efficiency. This study employs a coupled flow and geomechanics model to investigate the poroelastic changes induced by parent well depletion in the infill zone. Based on poromechanics, the temporal and spatial changes in pore pressure, minimum horizontal principal stress, breakdown pressure, and maximum horizontal principal stress orientation are quantified. Pore pressure is used to estimate the remaining hydrocarbon exploitation potential in the infill zone, while minimum horizontal principal stress, breakdown pressure, and maximum horizontal principal stress orientation are used to estimate the difficulties of establishing hydraulic fracture networks in the infill zone. Results show that increasing parent well spacing helps to maintain the pore pressure in the infill zone, while the difficulties of initiating hydraulic fracture networks in the infill zone are slightly increased. Tight well spacing intensifies the infill zone depletion and lowers the infill well development potential, while the breakdown pressure is decreased which can facilitate future infill well fracturing. The poroelastic effect of parent well spacings on the infill zone is not monotonic.

KEYWORDS

case study, infill zone, numerical simulation, poroelasticity, shale oil
hydrocarbons in the infill zones between the tightly spaced wells are not efficiently produced and infill well drilling and completion can help to produce the infill zones.\textsuperscript{3} Based on poromechanics, depletion caused by the production of tightly spaced fractured wells alters the poroelastic parameters in the producing wells and in the infill zones, which indicates that the pore pressure and in situ stress are also changed. Such poroelastic changes directly affect the hydraulic fracturing performance and the hydrocarbon production potential in the infill zones.\textsuperscript{9,10} Therefore, it is meaningful to investigate how tightly spaced hydraulically fractured wells and their spacing affect the pressure and stress evolutions in infill zones.

The efficacy of exploitations in infill zones has become a key issue to address. In some fields, the majority of newly drilled wells are infill wells instead of tightly spaced parent wells.\textsuperscript{11} Field observations indicate that the hydraulic fracturing quality and performance of wells in the infill zone can be largely influenced by previously placed parent wells. Negative impacts on the fracturing quality and production in infill zones have been reported in the major shale plays in North America.\textsuperscript{12,13} In addition to the impact on well production, the impact of parent well depletion on infill zones can be proved by fracture hits, pressure oscillation, DAS and DTS data, and microseismic data.\textsuperscript{14,15} The drilling and completion of horizontal wells in infill zones can also cause well control problems in parent wells as the infill well fractures connect to pre-existing fracture networks and the fracturing fluids and proppants enter the parent wells. In severe cases, such unwanted impacts lead to the loss of horizontal wells, which makes it important to understand the underlying mechanism.\textsuperscript{16,17}

To improve the understanding of these observations in infill zones, the evolution of the poroelastic characteristics has been investigated.\textsuperscript{18} Coupled flow and geomechanics modeling is widely accepted as a useful tool for the quantification of the pressure and stress changes in infill zones. This modeling strategy involves Biot's theory, mass balance, and momentum balance.\textsuperscript{19} They couple the porous media flow with geomechanics and can calculate the depletion-induced stress alterations. The specific coupling strategies include full coupling, explicit coupling, and iterative coupling. Dean et al.\textsuperscript{20} compared the performance of the fully coupled flow and geomechanics model with other strategies. They indicate that iteratively and explicitly coupled solutions can be very close to the fully coupled solution when the coupling tolerances are strict. Sequentially coupled flow and geomechanics modeling can largely improve the computational efficiency. However, the level of the convergence and stability of the model can be decreased.\textsuperscript{21,22} Roussel et al.\textsuperscript{23} presented a modeling workflow to evaluate the poroelastic changes in the infill zone and predicted the hydraulic fracture paths for an infill well. They found that parent well depletion can divert the infill well hydraulic fractures as both the magnitude and the orientation of the principal stress in the infill zone are altered. Effects of parent well production history and the rock mechanical properties of shale oil reservoir rocks on the poroelastic were discussed by Guo et al.,\textsuperscript{24,25} where an initial increase in principal stress was observed as the effect of pore pressure depletion is not strong in the early stages. To poroelastically mitigate the negative impacts of parent well depletion on the infill zone, loading fluids in parent wells were identified as a possible strategy as the injected fluids partially recover the in situ stresses.\textsuperscript{24,25} Field tests of this strategy in McKenzie County, North Dakota, proved its feasibility.\textsuperscript{26,27} Huang et al.\textsuperscript{28} then established a correlation between reservoir depletion, fracturing, refracturing, and geological characteristics such as stress barriers in three-dimensional modeling, where poroelasticity is an underlying controlling factor. Poroelastic evolutions in the reservoir are correlated with the quality of hydraulic fracturing operations in infill zones.\textsuperscript{24,25,29,30}

The specific spatial and temporal evolution patterns of poroelastic parameters should be quantitatively investigated for better exploitation efficacy in infill zones, and well spacing is a critical parameter to consider when developing shale oil reservoirs with tightly spaced hydraulically fractured wells. In this study, the effect of parent well spacing on the poroelastic evolutions in the infill zone is examined in a case study in a shale oil reservoir in northwestern China. A coupled flow and geomechanics model is introduced for the computation of the spatial and temporal evolutions of pressure and in situ stress. This study quantifies the poroelastic behaviors in the infill zone and provides insights into the optimization of well spacing in the study area.

2 | METHODOLOGY

In this study, a 3D coupled flow and geomechanics model is presented for the computation of the spatial and temporal evolutions. Based on the physics of the continental shale oil in the study area,\textsuperscript{31,32} the fluid flow model considers the two-phase water and oil flow isothermally with mass balance. The geomechanical problem considers the momentum balance between stress components and a linear elastic assumption is employed. The Biot’s theory is used to describe the consolidation in fully saturated porous media.

Based on mass balance and flow diffusivity, the two-phase water and oil equations are:

\[
\frac{\partial (\rho_s \phi \rho_w)}{\partial t} + \nabla \cdot (\rho_w \mathbf{u}_w) = s_w
\]  

(1)
\[
\frac{\partial (\phi S_o \rho_o)}{\partial t} + \nabla \cdot (\rho_o u_o) = s_o \tag{2}
\]

where \( \phi \) is porosity; \( t \) is time; \( S_o \) is water saturation; \( \rho_w \) is water density; \( u_w \) is velocity of the fluid flow for the water phase; \( s_w \) is the sink/source for water; \( S_i \) is oil saturation; \( \rho_o \) is oil density; \( u_o \) is velocity of the fluid flow for the oil phase; \( s_o \) is the sink/source for oil. In addition, the saturations of the two phases follow:

\[
S_o + S_w = 1 \tag{3}
\]

The velocity for water and oil phases can be expressed as follows:

\[
u_o = -\frac{kk_m}{\mu_o} (\nabla p + \rho_o g) \tag{4}
\]

\[
u_w = -\frac{kk_m}{\mu_w} (\nabla p + \rho_o g) \tag{5}
\]

where \( k \) is absolute permeability; \( k_m \) is relative permeability for the oil phase; \( k_v \) is relative permeability for the water phase; \( \mu_o \) is oil viscosity; \( \mu_w \) is water viscosity; \( p \) is pressure; \( g \) is gravitational acceleration term.

To treat the slightly compressible fluids in the porous media in shale oil reservoirs, compressibility terms are introduced for the water phase and the oil phase as follows:

\[
c_w = \frac{1}{\rho_w} \frac{\partial \rho_w}{\partial p} \tag{6}
\]

\[
c_o = \frac{1}{\rho_o} \frac{\partial \rho_o}{\partial p} \tag{7}
\]

where \( c_w \) and \( c_o \) are compressibility terms for water and oil.

After describing the fluid flows in the porous media, the geomechanical problem is discussed. The constitutive relationship for the reservoir rock is assumed as linear elasticity. The equilibrium between stress components is described by the use of the Cauchy stress tensor:

\[
\nabla \cdot \sigma + \rho_b g = 0 \tag{8}
\]

where \( \sigma \) is total stress tensor; \( \rho_b \) is the bulk density. The total stress can be further described as follows:

\[
\sigma = \sigma' - \alpha \rho_b I \tag{9}
\]

where \( \sigma' \) is effective stress; \( \alpha \) is Biot’s coefficient; \( I \) is a second-order identity tensor. It describes the effective stress in the reservoir induced by depletion.

The coupling between the fluid flow problem and the geomechanical problem in the reservoir is achieved by

\[
(\phi c_i + \frac{\alpha - \phi}{K_s} \frac{\partial p}{\partial t} + \frac{\partial \hat{c}_i}{\partial t} + \nabla \cdot u_i = 0 \tag{10}
\]

where \( i \) is the subscript for a certain phase; \( K_s \) is solid grain modulus; \( \epsilon_v \) is volumetric strain. Thus, the pressure and saturation changes and stress evolutions can be calculated. \(^{21,22}\) In the numerical solution, finite element and finite difference methods are used for spatial discretization and temporal discretization, respectively. Implicit time stepping is involved for better stability, and Galerkin methods are used in the finite element methods. The quadratic Lagrangian shape function is used for the porous media flow problem, while the quadratic serendipity method is used in the discretization of the geomechanical problem. The flow and geomechanics problems are fully coupled for better stability and accuracy.

3 | BASE CASE MODELING

The study area involved in this study is the shale oil reservoir in the Permian Formation in Jimsar Sag, Junggar Basin located in northwestern China. Continuous commercial shale oil production has been achieved in the Upper Lucaogou Formation and in the Lower Lucaogou Formation. Tightly spaced horizontal wells are drilled and completed in both formations as it is necessary to get hydraulic fracturing involved for commercial shale oil production. The Upper Formation has been extensively developed, and the next major target is the Lower Formation where sweet spots have been identified. \(^{33}\)

Hydraulic fracturing and shale oil production performance observed in previously drilled and completed wells indicate that parent well spacing is a key parameter. When the well spacing is too large, the overall production cannot reach the optimum. When the well spacing is too tight, pressure and stress interference can become excessive, and the hydraulic fracturing quality and averaged production in individual wells can be negatively affected. As a result, it is meaningful to evaluate how parent well spacing affects the pressure and stress evolutions in the Lower Permian Lucaogou Formation as it is directly related to the overall exploitation efficacy in Jimsar Shale Oil.

In this study, a 3D coupled flow and geomechanics model is established for a parent well depletion scenario in the Lower Permian Lucaogou Formation. The buried depth is 3800 m with a reservoir pressure of 56 MPa. The maximum horizontal principal stress is 84 MPa, and the
minimum horizontal principal stress is 70 MPa. A tensile strength value of 10 MPa is obtained. Log interpretations and rock mechanical tests are used to determine these mechanical properties, where typical logs such as acoustic logs, resistivity logs, and GR logs are used in the interpretation, and tri-axial tests are used for elastic property evaluation.34,35 The permeability of the matrix is 0.047 mD with a porosity of 8.4%. Two parent wells with a well spacing of 200 m are in the model, and a single stage in each well is considered. Each stage has three fracture clusters with infinite permeability for the representation of main fractures, while the inter-fracture areas are modeled as stimulated reservoir volumes (SRV) for the consideration of improved permeability caused by hydraulic fracturing. The fracture half-length is 80 m, and the fracture spacing is 20 m. The fracture height is 10 m as fractures are contained in the payzone. For the reservoir rock, the elastic modulus is 20 GPa and the Poisson’s ratio is 0.22. The mesh of the 3D model has a dimension of 200 m by 600 m by 30 m. An infill box is also prescribed for the analysis of poroelastic values in the numerical study (Figure 1). The base case has a well spacing of 200 m. Since the fracture half-lengths are 80 m, the distance between fracture tips in the two parent wells is 40 m. The zone between fracture tips of two parent wells is the infill zone where the poroelastic behaviors are specifically investigated.

Since the target payzone is not developed, a three-year production prediction is carried out in the base case model using a well spacing of 200 m which is typically used in this field. The bottom hole pressure for production is kept at 25 MPa. Figure 2 shows the distribution of pressure after 12, 24, and 36 months of production. Due to the effect of the pressure boundaries,
pressure values at hydraulic fractures are all equal to the depletion pressure of 25 MPa. After 12 months, pressure depletion is mainly contained in SRVs and the infill zone only has slight pressure decreases. As the production time increases to 24 months, the volume experiencing pressure depletion increases, and the infill zone has stronger pressure decreases. After 36 months, the pressure in the infill zone is significantly decreased, indicating that the exploitation potential is also decreased. Figure 3 shows the daily oil production rate from the outer fracture and the inner fracture in the parent wells. Because of symmetry, only two production curves are presented. Note that the curves are oil production from individual fractures and the two outer fractures have the same production rate. The daily oil production rate drops drastically in the first year, while it becomes more stable after 12 months of production. The outer fracture generally has a higher production rate curve as the outer fractures can deplete greater reservoir volumes with higher pore pressures. In the beginning, each fracture can produce about 2000 kg oil daily. This number drops to below 250 kg daily after more than two years of production.

Due to symmetry, the first half is presented. In the base case, the spacing between the two parent wells is 200 m, and the half-length of hydraulic fractures is 80 m. Thus, an infill zone with a length of 40 m in the y-direction is obtained. The distribution of pore pressure and the minimum horizontal principal stress (\(S_{\text{hmin}}\)) at the infill zone is presented in Figure 4. Specifically, results along the line of \(y = 0\) m and \(z = 0\) m as in Figure 1 are plotted after 12, 24, and 36 months of parent well depletion. The center of the infill zone has greater decreases in pore pressure and minimum horizontal principal stress than the boundaries. This is caused by the depletion induced by parent wells and their associated hydraulic fractures. As the production time increases, the decreases in pressure and minimum principal stress intensify. It is noted that for the \(S_{\text{hmin}}\) distribution after 12 months of production, there is an increase starting from \(x = 60\) m. This is because the effective stress is increased by pore pressure depletion and the center of the infill zone experiences greater effective stress increases. The reason why the \(S_{\text{hmin}}\) curve is generally dented in the middle is that the effect of pressure depletion outweighs the effect of effective stress increase.

The results in Figure 4 indicate that, due to the production in fractured parent wells, the poroelastic parameters in the infill zone are largely altered. The decrease in pore pressure implies that when the infill zone is developed, the driving force for hydrocarbon fluid flows is smaller than parent well development, indicating a smaller potential for hydrocarbon production. However, due to the decrease in pore pressure, the \(S_{\text{hmin}}\) values are also decreased. This indicates that the energy required to establish hydraulic fracture networks from the infill well can be smaller than the parent wells. Therefore, the effects of poroelastic
changes in the infill zone on future development are not monotonic: The decrease in pore pressure lowers the driving force for hydrocarbon flows, while the decrease in $S_{\text{hmin}}$ lowers the energy required to fracture the infill zone. Figure 5 shows the effect of depth on the distribution of $S_{\text{hmin}}$ values in the infill line ($-100 \leq x \leq 100$ m and $y = 0$ m) at three different depths of $z = 0$, 10, and $-10$ m after 36 months of production. A boundary effect is observed in the numerical results. At the center of the infill zone, $S_{\text{hmin}}$ values increase as the depth increases. At the boundary, $S_{\text{hmin}}$ values decrease with depth.

4 | EFFECTS OF PARENT WELL SPACING ON PoroELASTIC BEHAVIORS IN THE INFILL ZONE

Tightly spaced horizontal wells are usually involved in the development of shale oil resources. When the well spacing is too loose, the overall exploitation efficiency can be undermined; when the well spacing is too tight, competition between wells and inter-well interference can negatively impact the single-well averaged fracturing and production performance. In consequence, the determination of well spacing is a key issue for shale oil development. In this section, a parametric study is carried out to investigate the effect of well spacing on the poroelastic changes in the infill zone. Several well spacings (200, 300, and 400 m) and their corresponding pressure and stress evolutions are presented.

Figure 6 presents the distribution of pore pressure after 12 and 36 months of parent well production. The depletion within SRVs is thorough, with pore pressure values equal or close to the production pressure of 25 MPa. Reservoir
volumes near SRVs experience pressure gradient changes, while volumes near SRVs experiencing pressure decreases expand with parent well production time. For the smallest well spacing of 200 m, the infill zone experiences pressure depletion after 12 months, while this effect furthers after 36 months of production. When the well spacing increases to 300 m, there is no significant pressure decrease in the infill zone after 12 months of production, while the pressure decrease becomes more noticeable after 36 months. This indicates that increasing the well spacing delays the pressure depletion in the infill zone. When the well spacing increases to 400 m, there is no significant pressure decrease in the infill zone even after 36 months of parent well depletion. Thus, a higher well spacing helps to maintain the pore pressure in the formation and preserve the potential for hydrocarbon production in the infill zone.

Figure 7 shows the evolved minimum horizontal principal stress within the reservoir for three different well spacings. Compared with the original $s_{\text{hmin}}$ of 70 MPa, the evolved $s_{\text{hmin}}$ values are smaller. Since total stress is related to pore pressure and effective stress, parent well depletion decreases the pore pressure and the total stress is consequently decreased as well. In general, the trends of $s_{\text{hmin}}$ evolution are similar to those for pore pressure in Figure 6, as pore pressure changes largely govern total stress changes. However, it is also noticed that the evolution of $s_{\text{hmin}}$ is more extensive in terms of affected reservoir volumes. This indicates that the $s_{\text{hmin}}$ changes travel further than pore pressure changes caused by depletion in SRVs in parent wells. Based on these results, a higher well spacing leads to greater $s_{\text{hmin}}$ values in the infill zone. It implies that it requires more energy to establish hydraulic fracture networks in the infill zone when the well spacing is large.

To better quantify the effect of parent well spacings on the poroelastic changes in the infill zone, the average pore pressure, $s_{\text{hmin}}$, and breakdown pressure and their temporal evolutions in the infill zone are studied. A box representing the potential SRV of a future infill well right at the center of the infill zone is introduced. It has the same size as the parent well SRVs. The infill zone box has a width of 60 m, a length of 160 m, and a height of 10 m. The location and the size of it do not change in different well spacing scenarios. When calculating the breakdown pressure in the infill zone, the following expression is involved:

$$P_{V}^f = 3S_{\text{Hmax}} - S_{\text{hmin}} - \alpha p + S_t$$  \hspace{1cm} (11)$$

$$P_{H}^f = 3S_{\text{Hmax}} - S_v - \alpha p + S_t$$  \hspace{1cm} (12)$$

where $P_{V}^f$ and $P_{H}^f$ are breakdown pressure estimations for vertical wellbore and horizontal wellbore, respectively; $S_{\text{Hmax}}$ is maximum horizontal principal stress; $S_v$ is vertical
principal stress; \( S_t \) is tensile strength.\(^{36}\) Note that this breakdown pressure is estimated for fracturing in a vertical wellbore and in a horizontal wellbore (normal faulting stress regime) with no fluid penetration. Although breakdown pressure estimation for multi-stage fracturing in cased horizontal wells can be more complicated, this estimation serves as a general index for the easiness of establishing fractures in a future infill well in the absence of detailed fracturing designs in the parametric study presented in this work.

The temporal evolution of the average pore pressure in the infill zone and in the parent well SRV is shown in Figure 8. Three different well spacings of 200, 300, and 400 m are considered. Compared with the initial pore pressure of 56 MPa, the 400 m well spacing generally has insignificant impacts on the pressure in the infill zone. In this well spacing scenario, the distance between the fracture tips in two parent wells is 240 m, resulting in insignificant parent-well depletion-induced pore pressure changes in the infill zone with a width of 160 m. When the well spacing decreases to 300 m, the distance between parent well hydraulic fractures is 140 m. This leads to overlaps between the infill zone and the parent well SRVs. Thus, the effect of parent well depletion on the infill zone is enhanced compared with the 400 m well spacing scenario. Note that at time 0, the average pressure is already dropped below 56 MPa. This is because the infill zone partially covers parent well SRVs. Due to the infinite hydraulic fracture conductivity assumption used in the methodology, hydraulic fractures serve as the pressure sink and the bottom hole pressure takes effect starting from time 0. For the closest well spacing of 200 m, the effect on infill zone pressure decrease is the most significant. The average pressure in the infill zone drops below 30 MPa after 10 months of parent well production. Therefore, the potential for hydrocarbon production in a future infill well can be largely limited if the parent well spacing is too tight. In contrast, the effect of well spacing on the temporal changes in pore pressure in parent well SRVs is not significant. This is because pressure depletion is strong in parent well SRVs, and this effect largely outweighs the effect of well spacing.

FIGURE 8 Effects of well spacing on temporal changes in the average pressure in the infill zone (left) and in the parent well SRV (right)

FIGURE 9 Effects of well spacing on temporal changes in the average \( S_{\text{min}} \) in the infill zone (left) and in the parent well SRV (right)
The effect of well spacing on the changes in $S_{\text{hmin}}$ in the infill zone and in the parent well SRV is quantified by Figure 9. Compared with the initial $S_{\text{hmin}}$ of 70 MPa in the x-direction, the infill zone experiences different degrees of $S_{\text{hmin}}$ decreases as parent well spacings change. The trends of the profiles are similar to those for pressure. In the 400 m well spacing scenario, the change in $S_{\text{hmin}}$ is insignificant. As the well spacing decreases to 300 and 200 m, $S_{\text{hmin}}$ decreases become more drastic, implying that it is easier to establish and maintain the hydraulic fracture network in the future infill well. Similar to the observation in Figure 8, the effect of well spacing on $S_{\text{hmin}}$ in parent well SRVs is insignificant due to the drastic depletion in SRVs.

To further understand the poroelastic changes in the infill zone and their relationship with the easiness of establishing future hydraulic fractures in the infill zone, the temporal changes in the estimated breakdown pressure for vertical well and horizontal well fracturing are presented in Figure 10.

Before parent well depletion, the breakdown pressures for vertical well fracturing and horizontal well fracturing are 136 and 116 MPa based on Equations (11) and (12). For the vertical fracturing scenario with a 200 m well spacing, the effect of parent well depletion is significant. The initial breakdown pressure at time 0 is about 122 MPa, as the infill zone overlapped with parent well SRVs experiences pressure depletion at time 0. Later on, the average breakdown pressure in the infill zone keeps dropping. This indicates that the required breakdown pressure to initiate hydraulic fractures in the infill zone drops for about 16 MPa after 36 months of parent well depletion. Note that this estimate is based on fracturing vertical boreholes. When the parent well spacing increases to 300 m, the breakdown pressure at time 0 increases to about 129 MPa. After 36 months, the breakdown pressure drops to 117 MPa, which is not significantly dropped if compared with the original breakdown pressure. For the greatest well spacing 400 m, the breakdown pressure is always higher than other scenarios. This is because the large well spacing ensures that the infill zone barely experiences pressure depletions, while the propagation of effective stress increases travels to the infill zone, leading to higher breakdown pressure profiles. It can be concluded that the effect of well spacing is the greatest when the well spacing is the smallest, as a tight spacing leads to stronger pressure depletion in the infill zone. Breakdown pressure estimation for horizontal well fracturing is also presented, and the trends are very similar to those for vertical well fracturing estimations. The only difference is that the breakdown pressure values for horizontal well fracturing is generally lower than those for vertical well fracturing. This corresponds to previous studies where a small horizontal principal stress difference leads to lower $P_{\text{H}}$ compared to $P_{\text{V}}$ in normal faulting stress regimes.

Based on the observations from Figures 8–11, a well spacing of 200 m results in the lowest breakdown pressure required for future infill well fracturing. However, it also leads to the lowest pore pressure in the infill zone, implying low hydrocarbon exploitation potentials. For a well spacing of 300 m, a 36-month parent well depletion decreases the pore pressure for about 11 MPa and decreases the breakdown pressure for about 2.5 MPa in the infill zone. This indicates an intermediate level of parent well depletion impact on poroelastic changes in the infill zone. For a well spacing of 400 m, the pore pressure decreases for about 1 MPa, while the breakdown pressure increases for about 1 MPa in the infill zone, which means that the poroelastic changes are insignificant.

Except for pore pressure, minimum horizontal principal stress, and breakdown pressure, it is also relevant to
WANG et al. study the reorientations of the maximum horizontal principal stress ($S_{Hmax}$) in the infill zone caused by parent well depletion. This is because the orientation of maximum horizontal principal stress is a key governing parameter for hydraulic fracture propagation. Figure 11 demonstrates the orientation of $S_{Hmax}$ after 36 months of parent well production for the three well spacing scenarios. Note that red arrows indicate the local orientations of $S_{Hmax}$ and the initial $S_{Hmax}$ always points in the y-direction. In general, there is no total stress reversal in this case study. However, reorientations up to about $45^\circ$ are observed around SRV boundaries. For the infill zone, the 200 m well spacing results in very insignificant $S_{Hmax}$ reorientations, while the 300 and 400 m well spacing scenarios lead to certain $S_{Hmax}$ reorientations. Therefore, for the 300 and 400 m well spacing scenarios, a future infill well fracturing job can experience greater frictional loss within the fractures during pumping, as the likelihood of non-planar fracture growths is higher in these cases with more reorientations in the principal stress field.\textsuperscript{34,35} Combined with the observation in Figures 8-10, it is estimated that, although the pore pressure is largely depleted in the infill zone, the 200 m spacing can reduce the energy required to establish infill well fracture networks.

5 | CONCLUSION

In this study, based on a coupled flow and geomechanics model, the effect of parent well spacing on the poroelastic changes in the infill zone in a case study is quantitatively investigated. Parent well depletion depletes the pore pressure, alters the minimum horizontal principal stress and breakdown pressure, and reorients the direction of the maximum horizontal principal stress in the infill zone. In conclusion:

1. When the parent well spacing is very tight, the candidate infill zone overlaps with parent well SRVs. This reduces the potential of hydrocarbon production in the infill zone as parent wells can largely deplete the infill zone before there is any infill well drilling, completion, and production.

2. Although a tight parent well spacing usually results in lower pore pressure in the infill zone after parent well production, it also leads to lower minimum horizontal principal stress and lower breakdown pressure. It also avoids significant reorientation of maximum horizontal principal stress in the infill zone. These effects
jointly make it easier to initiate hydraulic fracture networks in the future infill well in the infill zone.

3. Generally, increasing parent well spacing reduces the competition between parent wells and infill wells in terms of pore pressure interference, and the infill zone maintains greater potentials for future hydrocarbon production. However, based on the coupled flow and geomechanics study, parent well depletion with a wide parent well spacing can sometimes increase the difficulties of initiating hydraulic fractures in the infill zone.

4. In terms of future development of the infill zone, the effect of parent well spacing is not monotonic. Increasing the well spacing helps to maintain the pore pressure in the infill zone, while it can slightly increase the difficulties of initiating hydraulic fractures in the zone. Decreasing the well spacing lowers the hydrocarbon production potentials in the infill zone. However, it also lowers the difficulties of initiating fractures in the infill zone. A case-by-case study helps to determine the optimum parent well spacing in a shale oil development scenario.

In this case study, it is noted that greater well spacings help to maintain the original pore pressure in the infill zone, while they lead to higher breakdown pressures for infill well fracturing. A well spacing of 300 m can preserve the infill zone pressure and decrease the breakdown pressure, and it can be a candidate well spacing in this specific case.

ACKNOWLEDGMENTS

The authors acknowledge the financial support from the National Natural Science Foundation of China (Nos. 51904314, 51991362, and U19B6003-05), and the Fundamental Research Funds for the Central Universities and the Science Foundation of China University of Petroleum, Beijing (No. 2462018JYRC031).

ORCID

Xuyang Guo https://orcid.org/0000-0002-1826-3082

REFERENCES

1. Stegent N, Wagner A, Stringer C, Tompkins R, Smith N. Engineering approach to optimize development strategy in the oil segment of the eagle ford shale: a case study. SPE Prod Oper. 2013;28:226-234.
2. Li J, Yu W, Guerra D, Wu K. Modeling wettability alteration effect on well performance in Permian basin with complex fracture networks. Fuel. 2018;224:740-751.
3. Zhi D, Guo X, Wang W, et al. Fracturing and production analysis of the efficacy of hydraulic fracture stage reduction in the improvement of cost-effectiveness in shale oil development: a case study of Jimsar shale oil, China. Energy Sci Eng. 2021;9:1337-1348.
4. Zhang F, Wu J, Huang H, et al. Technological parameter optimization for improving the complexity of hydraulic fractures in deep shale reservoirs. Nat Gas Ind. 2021;41(1):125-135.
5. Dahi Taleghani A, Gonzalez-Chavez M, Yu H, et al. Numerical simulation of hydraulic fracture propagation in naturally fractured formations using the cohesive zone model. J Petrol Sci Eng. 2018;165:42-57.
6. Hou B, Chang Z, Fu W, et al. Fracture initiation and propagation in a deep shale gas reservoir subjected to an alternating-fluid-injection hydraulic-fracturing treatment. SPE J. 2019;24(4):1839-1855.
7. Xie J, Tang J, Yong R, et al. A 3-D hydraulic fracture propagation model applied for shale gas reservoirs with multiple bedding planes. Eng Fract Mech. 2020;2020(228):106872.
8. Manchanda R, Bhardwaj P, Hwang J, Sharma MM. Parent-Child Fracture Interference: Explanation and Mitigation of Child Well Underperformance. SPE Hydraulic Fracturing Technology Conference and Exhibition; 2018. doi:10.2118/189849-MS
9. Kurtoglu B, Salman A. How to Utilize Hydraulic Fracture Interference to Improve Unconventional Development. Presented at the Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, 9–12 November. SPE-177953-MS; 2015.
10. Wang H, Chen Z, Chen S, et al. Production forecast and optimization for parent-child well pattern in unconventional reservoirs. J Petrol Sci Eng. 2021;203:108899.
11. Lindsay G, Miller G, Xu T, et al. Production Performance of Infill Horizontal Wells vs. Pre-existing Wells in the Major US Unconventional Basins. Presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, 23–25 January. SPE-189875-MS; 2018.
12. Esquivel R, Blasingame TA. Optimizing the Development of the Haynesville Shale—Lessons Learned From Well-to-Well Hydraulic Fracture Interference. Presented at the Unconventional Resources Technology Conference, Austin, Texas, 24–26 July. URTEC-2670079-MS; 2017.
13. Rainbolt MF, Esco J. Frac Hit Induced Production Losses: Evaluating Root Causes, Damage Location, Possible Prevention Methods and Success of Remediation Treatments, Part II. Presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, 23–25 January. SPE-189853-MS; 2018.
14. Boone K, Crickmore R, Werdeg Z, Laing C, Molenaar M. Monitoring Hydraulic Fracturing Operations Using Fiber-Optic Distributed Acoustic Sensing. Proc. 3rd Unconv. Resour. Technol. Conf.; 2015.
15. Courtier J, Gray D, Smith M, et al. Legacy Well Protection Refrac Mitigates Offset Well Completion Communications in Joint Industry Project. SPE Liq. Basins Conf. – North Am.; 2016.
16. Morales A, Zhang K, Gakhhar K, et al. Advanced modeling of interwell fracturing interference: an eagle ford shale oil study-refracturing. SPE Hydraulic Fracturing Technology Conference, February 2016, The Woodlands, Texas, USA; 2016.
17. Jacobs T. Oil and gas producers find frac hits in shale wells a major challenge. J Petrol Technol. 2017;69(4):29-34.
18. Guo X, Jin Y, Zi J, et al. Numerical investigation of the gas production efficiency and induced geomechanical responses in marine methane hydrate-bearing sediments exploited by
depressurization through hydraulic fractures. *Energy Fuels*. 2021;35(22):18441-18458.

19. Cheng W, Jiang G, Cheng W, Jiang G. A porochemothermoelastic coupling model for continental shale wellbore stability and a case analysis. *J Petrol Sci Eng*. 2019;182:106265.

20. Dean RH, Gai X, Stone CM, Minkoff SE. A comparison of techniques for coupling porous flow and geomechanics. *SPE J*. 2006;11(01):132-140.

21. Kim J, Tchelepi HA, Juanes R. Rigorous coupling of geomechanics and multiphase ow with strong capillarity. Presented at SPE Reservoir Simulation Symposium, The Woodlands, Texas, 21-23 February, SPE-141268-MS; 2011.

22. Kim J, Moridis G, Yang D, Rutqvist J. Numerical studies on two-way coupled fluid flow and geomechanics in hydrate deposits. *SPE J*. 2012;17(02):485-501.

23. Roussel NP, Florez H, Rodriguez AA. Hydraulic fracture propagation from infill horizontal wells. Presented at SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, 30 September-2 October. SPE-166503-MS; 2013.

24. Guo X, Wu K, An C, Tang J, Killough J. Numerical investigation of effects of subsequent parent-well injection on interwell fracturing interference using reservoir-geomechanics-fracturing modeling. *SPE J*. 2019;24(04):1884-1902.

25. Guo X, Wu K, Killough J, Tang J. Understanding the mechanism of interwell fracturing interference based on reservoir-geomechanics-fracturing modeling in Eagle Ford Shale. *SPE Reserv Eval Eng*. 2019;22(03):842-860.

26. Bommer P, Bayne M, Mayerhofer M, Machovoe M, Staron M. Re-Designing from Scratch and Defending Offset Wells: Case Study of a Six-Well Bakken Zipper Project, McKenzie County, ND. Presented at SPE Hydraulic Fracturing Technology Conference and Exhibition. SPE-184851-MS; 2017.

27. Bommer PA, Bayne MA. Active Well Defense in the Bakken: Case Study of a Ten-Well Frac Defense Project, McKenzie County, ND. Presented at SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, 23–25 January. SPE-189860-MS; 2018.

28. Huang J, Fu P, Hao Y, Morris J, Settgast R, Frederick R. Three-Dimensional Effects of Reservoir Depletion on Hydraulic Fracture Propagation. SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, USA, February 2019; 2019.

29. Zhang F, Dontsov E, Mack M. Fully coupled simulation of a hydraulic fracture interacting with natural fractures with a hybrid discrete-continuum method. *Int J Numer Anal Meth Geomech*. 2017;41(13):1430-1452.

30. Zhang F, Damjanac R, Maxwell S. Investigating hydraulic fracturing complexity in naturally fractured rock masses using fully coupled multiscale numerical modeling. *Rock Mech Rock Eng*. 2019;52(12):5137-5160.

31. Ding X, Zha M, Gao C, Qu J, Su Y, Huan L. Key Factors of Tight Oil Accumulation of Permian Lucaogou Formation in the Jimsar Sag of Junggar Basin, Northwestern China. Paper presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, San Antonio, Texas, USA, July 2015; 2015.

32. Zhao X, Zhou L, Pu X, et al. Formation conditions and enrichment model of retained petroleum in lacustrine shale: a case study of the Paleogene in Huanghua depression, Bohai Bay Basin, China. *Pet Explor Dev*. 2020;47(5):916-930.

33. Tang J, Fan B, Xiao L, et al. A new ensemble machine learning framework for searching sweet spots in shale reservoirs. *SPE J*. 2021;26(01):482-497.

34. Chen A, Guo X, Yu H, Huang L, Shi S, Cheng N. A parametric study of hydraulic fracturing interference between fracture clusters and stages based on numerical modeling. *Energy Explor Exploit*. 2021;39(01):65-85.

35. Chen B, Ji J, Lin J, et al. Experimental and numerical investigation of characteristics of highly heterogeneous rock mechanical responses in tight sandy conglomerate reservoir rock under triaxial compression. *Front Earth Sci*. 2021;9:735208.

36. Zhang J. *Applied Petroleum Geomechanics*. Gulf Professional Publishing; 2020.

---

**How to cite this article:** Wang Z, Guo X, Zheng G, et al. Effects of parent well spacing on the poroelastic behaviors in the infill zone in shale oil reservoirs: A case study in Jimsar Shale Oil, China. *Energy Sci Eng*. 2022;10:1043–1054. doi:10.1002/ese3.1059