Journal of Petroleum Science and Technology 10 (2020) 49-56
DOI:10.22078/jpst.2020.4054.1646

Journal of Petroleum Science and Technology

https://jpst.ripi.ir/

Hydraulic Fracturing Process in Tight Base Shale of Asmari Formation in Ahwaz Oilfield

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Abstract
Over the years, unconventional reservoirs have not received attention in Iran in light of easy oil. The most significant oil reservoir in Iran is Asmari formation of Ahwaz oilfield which has been producing oil by natural flow potential. Due to the gradual pressure drop of Asmari formation and oil price increment, production from the base shale of this formation has been considered. However, due to the low permeability of this layer, oil production has not been achieved, and it has still remained a challenge. Production of petroleum from tight/shale rocks has become possible by hydraulic fracturing. This study has hired Asmari formation base shale as case study for hydraulic fracturing simulations. This paper is focused on a scientific process to construct a lithology-dependent one-dimensional geomechanical model in an oil well which is completed in Asmari formation. Moreover poro-elastic formulation has been used for in-situ stress determination. In addition, the tectonic stress regime has been identified as normal faulting. Afterwards, a hydraulic fracturing operation has been designed by the FracCADE simulator. During hydraulic fracturing operations, an uncontrolled-height fracture may occur due to the absence of stress-barriers in bounding layers. A hydraulic fracture was designed for a sublayer of the Asmari base shale based on the constructed profile of in-situ stresses to constrain the vertical growth. Ultimately according to the results of the simulation, it was illustrated that the designed fractures did not cross the bedding interfaces of Asmari base shale.

Key words: Fracture migration, Unconventional reservoirs, In-situ stresses, Geomechanical model

Introduction
The depletion of the main producing layers in the Ahwaz field encouraged the operators to examine the most cost-effective way of developing the rest of the reservoir. Oil production in the Ahwaz field is derived from Asmari and Bangestan sandstone and carbonate layers within the reservoir, but some reservoir engineers have suggested developing the low-permeability base shale of Asmari formation using advanced stimulation technologies. The base shale of Asmari formation in SW of Iran is an oil-rich tight rock, and conventional acidizing treatments have not been successful considering the low permeability of this layer. Accordingly, the production interval must be stimulated using a hydraulic fracturing operation to produce oil from this tight layer.

Hydraulic fracturing is an extremely effective stimulation technique in unconventional low-permeability resources. In this operation, fluid is injected into reservoir rock with a high rate and pressure to break the rock and boost permeability to increase production [1].

Once pumping stops, the high-stress environment naturally closes the formed fractures. Therefore, the slurry stage is designed to transport propping agents into the fractures, which keep them open. Optimizing well placement and layer selection is a major challenge in hydraulic fracturing projects, especially in heterogeneous formation with different geomechanical properties (e. g. Poisson's ratio, Young's modulus, and in-situ stresses) [2]. It is proven that formation petrophysical and geomechanical parameters have significant effects on the geometric aspects of hydraulic fractures such as width, height, and length. Therefore, the formation of geomechanical modeling is a key task in hydraulic fracturing projects [3].

Thinly bedded reservoirs such as Asmari formation can be characterized using borehole imagery and detailed logs, allowing the field operators to build up an accurate picture of the formation in each well. This formation modeling process provides a hydraulic fracturing road map for production engineers. The next step is to select the best well and layer candidates.

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Received 2020-01-24, Received in revised form 2020-04-24, Accepted 2020-07-14, Available online 2020-08-31

Ahwaz reservoir has been in production since 1959. It is a water-driven and water run-off reservoir from west to east, which helps to maintain reservoir pressure. This reservoir is one of the most significant oil-fields in the world, and it can be counted as Iran's most strategic field with an underground area of 80 by 10.5 km. Asmari Formation of the Ahwaz field has 10 reservoir layers of sandstone, carbonate, and shale with more than 250 wells. Problems such as the depletion of the sandstone and carbonate layers and water-oil contact movement made it necessary to try oil production from base shale of this formation. However, due to the low permeability of this layer, oil production has not been possible so far. The candidate well in this study is a vertical well located at the north of Ahwaz, Iran, that was completed in the base shale of Asmari formation. Furthermore, it has low permeability; therefore, it has not been in production. Therefore, this well is a prime nomination for hydraulic fracturing simulation.
The amount of shale may significantly affect the geomechanical properties[4]. Accordingly, this paper aims to develop a scientific and integrated process to construct a geomechanical model in an oil well of the Asmari reservoir in the south-west of Iran. Afterwards, the hydraulic fracturing model will be built for base shale of this formation.

Materials and Methods

The first and also the best remediation activity for unconventional low-permeability reservoirs is hydraulic fracturing. The success in Hydraulic fracturing projects depends strongly on a geomechanical model, and for geomechanical modeling, calculation of static geomechanical properties is crucial. Three geomechanical properties related to rock brittleness are the Young's modulus (E), Poisson ratio (υ), and uniaxial compressive strength (UCS).
Elasticity Coefficients and Uniaxial Compressive Strength
Geomechanical properties can be calculated according to static (laboratory measurements) or dynamic manners (acoustic measurement). The sonic tool reacts to the elastic properties of the formation. The compressional and shear waves are used for estimating the medium elastic properties in dynamic form. The sonic tools measure the propagation times of these two waves. Then, several correlations can be applied to determine static elastic properties from dynamic forms [5]. It raises the question of which measurements of geomechanical properties should be used to model hydraulic fracturing. It was demonstrated by Dam et al. that the proper elastic properties for the hydraulic fracturing process are the static ones [6]. The dynamic elastic parameters are larger than the corresponding static data, and the difference is affected by pore pressure and structure, compaction, cementation, stress-strain rate, and wave amplitude [7]. There are no general mathematical relations between the static and dynamic data because of different reservoir rock lithologies. The static-dynamic correlations are obtained by studying and comparing the results of tests performed on laboratory core samples and the results of sonic log data. Furthermore, empirical relation for determining UCS and static Young's modulus using dynamic data sets for different lithologies are presented in the literature [8].
The Poisson's ratio, which relates to the sonic data, is obtained using the following equation [9]:

$$\vartheta_d = 1/2\frac{(V_p^2 - 2V_s^2)}{(V_p^2 - V_s^2)} \tag{1}$$

where ϑ_d is the dynamic Poisson ratio, V_p is the compressional wave velocity (m/s), and V_s is the shear wave velocity (m/s). The Poisson's ratio variations are in a narrow interval between 0.0 to 0.5. This point is true for both dynamic and static states. The difference between Poisson's ratio measured in the laboratory and one measured by sonic tools is minor. Thus, dynamic Poisson's ratio is usually appropriate to be used in the geomechanical modeling [7,10].
The mechanism of operation of sonic logs is different (e. g., monopole, and dipole), and it is necessary to thoroughly evaluate the quality of shear and compressional wave velocity. Sometimes sonic devices that are used do not provide shear wave velocity to reduce costs. In this case, it is necessary that a synthetic shear wave using empirical relationships or artificial intelligence based on the rock type be estimated. But these values need to be used with great care and caution. An equation of correlation (Equation 2) which is useful for a wide range of rocks from very tight to unconsolidated sediments is as follows [11]:

$$V_s = 0.7858 - 1.2344V_p + 0.7949V_p^2 - 0.1238V_p^3 + 0.006V_p^4 \tag{2}$$

where the unit of V_p and V_s is in km/s. Also, in this study, this correlation has been used by us for shear wave velocity estimation.
Mineralogy is the most important parameter controlling the pore system in unconventional reservoirs [12]. The pore system controls fluid storage capacity, and connections of the pore system control fluid flow through the porous media. In shale rocks, mineralogy also affects the geomechanical properties of the rocks. Therefore, hydraulic fracturing design strongly depends on the amount and mineralogy of the shale [13]. As stated before, Asmari Formation is composed of sandstone, carbonate, and shale layers. Therefore, it is is an essential task to focus on the mineralogy of the rock for Asmari geomechanical modeling.
The following correlation proposed by Najibi et al. relates the static Young's modulus (E_s) of Asmari carbonate rocks to only the compressional velocity (V_p) [8]:

$$E_s = 0.169V_p^{3.24} \tag{3}$$

where units of E_s is Gpa, and V_p is in km/s.
Static Young's modulus and uniaxial compressive strength are related in the presented Haug et al. correlation [14]:

$$E_s = 111UCS^{1.2} \tag{4}$$

where MPa is the unit of E_s and UCS.
Onyia developed the following correlation (Equation 5) for UCS by comparing the properties obtained from sonic logs in the cored wells and laboratory test results [15]:

$$UCS = [\frac{1}{k_1(\Delta t_c - k_2)^{(k_3)}}] + k_4 \tag{5}$$

where UCS is sonic-based uniaxial compressive strength (MPa), Δt_c is travel time in μs/ft and k_1, k_2, k_3 and k_4 are lithology dependent constants listed in Table 1.

Table 1 Constants for Onyia's correlation.

lithology	sandstone	shale	combination
k_1	2.48×10^{-6}	1.83×10^{-5}	1.34×10^{-5}
k_2	23.87	23.87	23.87
k_3	2.35	1,8	1,92
k_4	0	0	0

In unconventional reservoirs, unlike conventional reservoirs, appropriate logging tools for high precision calculation of petrophysical and geomechanical properties must be selected carefully. Geomechanical properties are used to determine the magnitude and direction of principal stresses, which are essential in designing the fracture job [2]. The whole process is accomplished in a workflow manner. In this study, equations (1-5) are used to determine the elasticity and strength parameters (e. g., UCS, E_s and ϑ_d) with emphasis on lithology owing to different lithologies present in Asmari formation. The results are presented in Figures 1 to 3.
Figures 1 and 2 show the variations of Poisson's ratio and Young's modulus in the Asmari Formation. The fracture orientation during a fluid injection can vary, and it depends on the distribution of Poisson's ratio and Young's modulus. The determination of these properties is essential to optimize hydraulic fracturing operations.
In order to calculate the fracture breakdown pressures of the formation under different conditions, it is necessary to consider the geomechanical properties of rock. When effective tensile stress exceeds a certain amount across a plane of rock, it causes tensile failure [16].
Kahraman et al. proposed a simple linear correlation which relates to uniaxial compressive strength (UCS) and tensile strength (T_0). The simple linear correlation is obtained using the following equation [17]:

$$UCS=10\cdot61\ T_0 \tag{6}$$

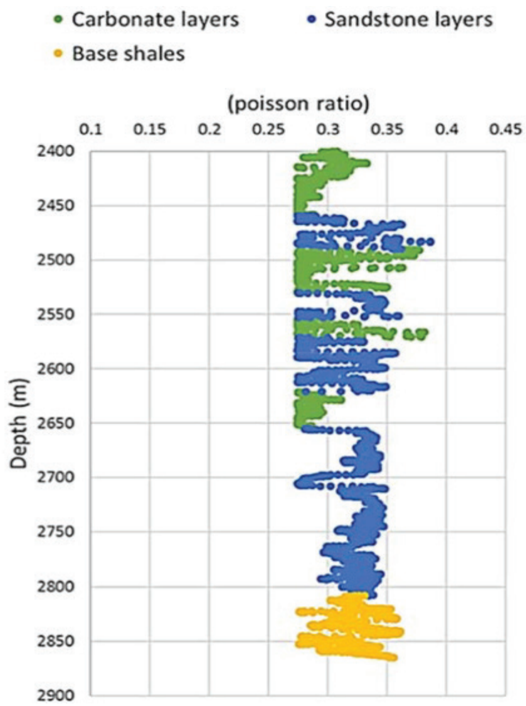

Fig. 1 Poisson's ratio.

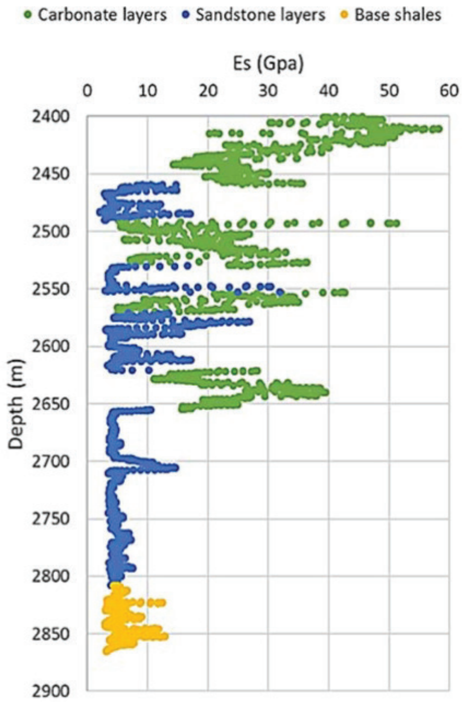

Fig. 2 Static Young's Modulus.

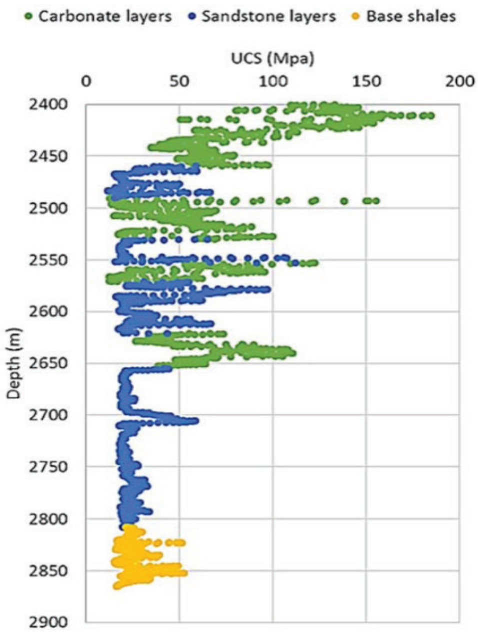

Fig. 3 Uniaxial Compressive Strength.

IN-SITU Stresses

The stress state of earth crust is one of the significant factors affecting the hydraulic fracturing design which can be described by magnitude and direction of three perpendicular principal stresses, S_H, S_h, and S_v.
The vertical stress is the weight of the sediment column, and it can be obtained indirectly from the following equation [18]:

$$S_v = \int_0^z \rho_z g dZ \cong \bar{\rho} g z \tag{7}$$

The maximum and minimum horizontal stress magnitudes depend strongly on the lithology and have challenges for geomechanical engineers [19].
A new stress polygon approach for horizontal in-situ stresses estimation was introduced in Equations 8 and 9 [20,21]:

$$S_H = \frac{\vartheta}{(1-\vartheta)}(S_v - \alpha P_p) + \alpha P_p + \frac{E_s}{(1-\vartheta^2)}(\varepsilon_y + \vartheta\varepsilon_x) \quad (8)$$

$$S_h = \frac{\vartheta}{(1-\vartheta)}(S_v - \alpha P_p) + \alpha P_p + \frac{E_s}{(1-\vartheta^2)}(\varepsilon_x + \vartheta\varepsilon_y) \quad (9)$$

P_p is pore pressure, α is Biot's constant which for more hydrocarbon reservoir is approximately 0.7 [22], and ε_x and ε_y are strain in S_h and S_H directions as given by equations (10) and (11) [18].

$$\varepsilon_x = \frac{S_v \vartheta}{E_s}\left(\frac{1}{1-\vartheta} - 1\right) \quad (10)$$

$$\varepsilon_y = \frac{S_v \vartheta}{E_s}\left(1 - \frac{\vartheta^2}{1-\vartheta}\right) \quad (11)$$

The purpose of geomechanical modeling is the determination of in-situ stresses amount and direction. The stability of the wellbore and fracture design is influenced by in-situ stresses [23]. The vertical stress rate in the Asmari reservoir is determined according to Equation 7, as seen in Figure 4. S_H and S_h along with the reservoir interval, are estimated using poroelastic formulations based on Equations 8 to 11, as seen in Figure 4. Based on the magnitudes of the three principal perpendicular stresses to each other, the following three situations occur [24]:

Normal stress regime (NF). In this case, the vertical stress is the greatest among the three types of stresses ($S_v>S_H>S_h$), and hydraulic fractures will be vertical.

Reverse faulting stress regime (RF). In this case, the vertical stress is the smallest among the three types of principal stresses ($S_H>S_h>S_v$), and hydraulic fractures will be horizontal lifting overburden.

Strike-slip faulting stress regime (SS). In the last case, the vertical stress is at the intermediate level between the other two stresses ($S_H>S_v>S_h$), and hydraulic fractures will be directional.

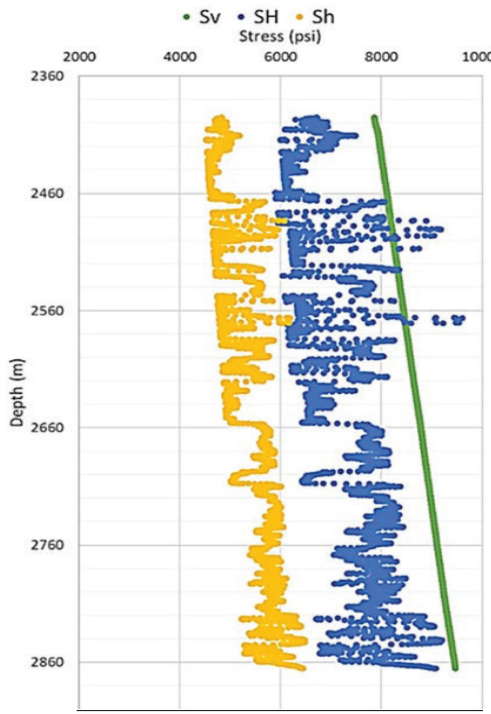

Fig. 4 In-situ stress rate of the Asmari reservoir in the study well.

As shown in Figure 4, the tectonic stress condition in this well is normal faulting type. Hydraulic fracture initiates and propagates almost perpendicular to the minimum principal stress [25]. Therefore, for the studied well, the hydraulic fractures would be vertical, perpendicular to S_h and propagate along the S_H.

Stress Barrier and Hydraulic Fracture Containment

Hydraulic fractures usually do not cross the margin of the selected layer when the minimum principal stress of the layer is less than the amount of this parameter in adjacent layers, and fractures will be "locked" in the target layer.

This is because of the higher horizontal stresses in a formation form a barrier and prevent fracture propagation in the adjacent layers [26].

The hydraulic fracture modeling results demonstrate that the diversity of the geomechanical properties (e.g., Young's modulus and Poisson's ratio) in the interface causes the fracture propagation in the selected layer. Although the most important factor in controlling the fracture height is the difference in geomechanical properties of the layers, sometimes exposure to a hard layer and reduced net pressure is effective in preventing uncontrolled height [27].

As demonstrated in Figure 5, 2830-2840 m interval (a sublayer interval of base shale of Asmari) is a proper candidate for hydraulic fracturing stimulation.

The challenging tip about shale-containing layers is that they usually have higher minimum principal stress than their adjacent layers. Consequently, there will be no stress-barrier around these layers to stop fracture.

Another issue of importance, as mentioned earlier, is that although the important factor deterring the growth of the fracture height is the difference in the geomechanical properties or the stress contrast of the layers, the fracture will stop in the face of dense rocks because the fracture cannot extend more [23].

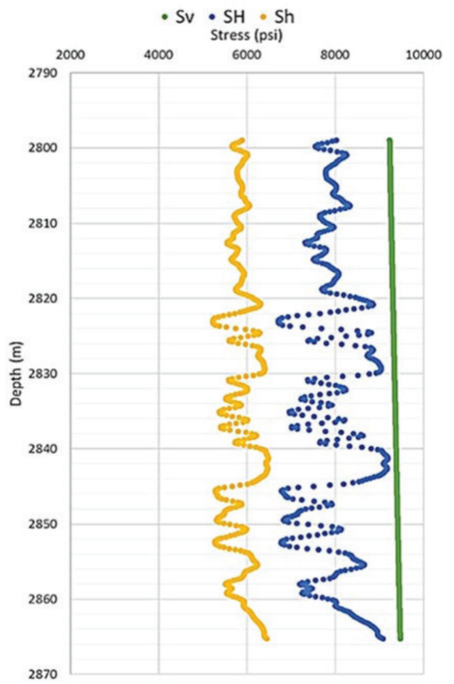

Fig. 5 In-situ stress magnitude on the base shales of the Asmari reservoir in the study well.

Breakdown Pressure

The primary breakdown formulation was introduced by Hubbert and Willis [25]. This model, which is known as the classic or conventional model, can calculate the failure or breakdown pressure of the formation. According to this model, breakdown occurs when the minimum tangential compressive stress in the periphery of a well exceeds the tensile strength of the rock.

Based on this model, the breakdown pressure is:

$$P_{bd}=3S_h-S_H-P_p+TS \quad (12)$$

where TS is the tensile strength of the rock, P_{bd} is the breakdown pressure, and P_p is the pore pressure. The hydrostatic pressure, which can be derived from the well static pressure surveys, has been used as pore pressure in this simulation.

Field experiences and laboratory experiments have shown that Equation 12 does not produce good results in some cases. In most cases, the actual breakdown pressure is higher than those predicted from this equation [28].

A new formula for predicting the breakdown (failure) pressure was developed by Zhang et al. This formula can calculate higher values than the predicted breakdown pressure of the early classical models and provides acceptable results based on the experimental and field data [29]:

$$P_{bd} = 3S_h - S_H - \alpha P_p + \sqrt{2}T_0 \quad (13)$$

The estimated break down pressure of this case study is given in Figure 6.

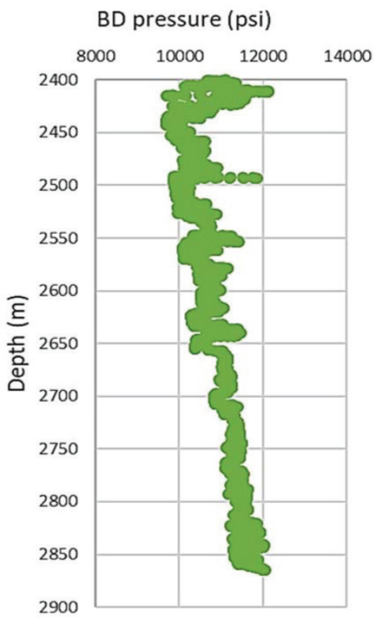

Fig. 6 The breakdown pressure.

Hydraulic Fracture Modeling of Base Shale of Asmari Formation

The principal components of the Asmari Formation of the Ahwaz field are high permeability and high porosity, siliciclastic-rich units that act as a fluid flow path. In contrast, the carbonate-rich components have lower porosity and permeability and are more resistant to fluid flow. The shale components often act as a flow barrier, but reservoir and petrophysical engineers believe that the base shale of this formation (A11 layer) can be used as a production layer due to its proper oil saturation.

Geological and geomechanical models of Asmari formation provide essential information about the connectivity of flow units, lithological heterogeneity, and stress distribution because the values of petrophysical and geomechanical properties are extremely variable at this formation. The geomechanical model of the understudy well followed the vertical lithology distribution. It is used as the basis for hydraulic fracture modeling. Moreover, hydraulic fracture modeling employs several disciplines simultaneously, including rock failure, geomechanics, fluid flow in porous media, and heat transfer. Therefore, this kind of modeling is very complex. In this research, a geomechanical model based on both petrophysical and geological data is presented. This model includes geomechanical properties, rock strength property, and stress distributions; in addition, the geomechanical properties vary in a vertical direction derived from logging data in the case study, combined with well completion and production data.

The geomechanical parameters of the layers along the path of propagation will affect the dimension of fracture by changing the stress condition of the area.

In tight rocks, the width of the fracture strongly depends on the variability of the Poisson's ratio, Young's modulus, conductivity, and productivity of adjacent rock layers.

Permeability or, in a general form, the conductivity of adjacent layers controls the leak-off coefficient. In other words, the width of the fracture is controlled by permeability. The geomechanical properties of adjacent layers, the thickness of the pay zone, and net fracturing pressure affect the fracture height growth. Therefore, to control the vertical growth of the fracture, the 2830-2840 m interval has been selected for fracturing stimulation. As shown in Figure 5, the stress magnitude of this interval is lower than the upper and lower surrounding sub-layers.

In this research, the FracCADE simulator and P3D model were utilized for fracture geometry prediction.

The hydraulic fracturing fluid is one of the most significant components of a hydraulic fracturing operation, and its most important tasks are to create fractures and carry proppants. The fracture fluid viscosity is the most important property of the fracturing fluid. Furthermore, they should break and get out of the fracture rapidly after pumping, because they have low friction pressure during pumping and exhibit low leak-off rate flowing through the created fracture [30]. YF550HT fracturing fluid type (available in the FracCADE database) is chosen for this simulation because of its medium viscosity, low friction factor, and clay stabilizing ability. It is produced by adding polymer, cross-linker, and also KCl as a clay stabilizer to the water.

Proppants act as obstacles to prevent the fracture from closing when injection of hydraulic fracturing fluid stops and to maintain a proper path to the wellbore. Using the right proppant with adequate concentration is essential to the success of a hydraulic fracturing operation. Proppant must be selected based on closure stress conditions. The difference between the bottom hole pressure and net fracturing pressure presents an approximate maximum effective closure stress on the proppant [30]. PR2000 type proppant (resin-coated sand) is selected because it provides the best fracture conductivity, its strength is adequate for closure stress, and its cost is lower

than ceramic proppants. The optimum pump schedule is shown in Table 2.
The results, driven from the hydraulic fracture model, are shown in Table 3 and Figure 7.

Results and Discussion

Since Asmari Formation has different strata, including carbonate, sandy, and shale layers, its rock properties such as porosity, permeability, and elastic moduli vary from layer to layer. Accordingly, an earth model is built for the understudied well, and vertical stress distribution is determined using petrophysical (log) data.
The heterogeneous geomechanical and geological properties of unconventional reservoirs (shale rocks) provide special challenges for hydraulic fracturing. In addition, there is usually no stress-barrier in the margins of these formations. Therefore, in some cases, it may cause high fractures. In the case of the study well, a sublayer of base shale of Asmari Formation with lower stress than surrounding sublayers is selected for hydraulic fracturing treatment.

Table 2 Pump Schedule.

	Stage Name	Pump Rate (bbl/m)	Fluid Name	Fluid Volume (gal)	Proppant Concentration (PPA)	Proppant Mass (lb)	Slurry Volume (bbl)	Pump Time (min)
1	PAD	30	YF550HT	93000	0	0	2214.3	73.8
2	2 PPA	30	YF550HT	1000	2	2000	26.0	0.9
3	4 PPA	30	YF550HT	6000	4	24005	169.4	5.6
4	6 PPA	30	YF550HT	26000	6	156031	791.6	26.4
5	8 PPA	30	YF550HT	65000	8	519994	2122.6	70.8
6	FLUSH	30	Water	5181	0	0	123.3	4.1

Table 3 Fracture Properties.

Hydraulic fracture half-length (ft)	1289
Propped fracture half-length (ft)	1138
Hydraulic height at well (ft)	193
Averaged propped width (in)	0.554
Effective FCD	6.8
Effective conductivity (md. ft)	7713
MAX surface pressure (psi)	6353

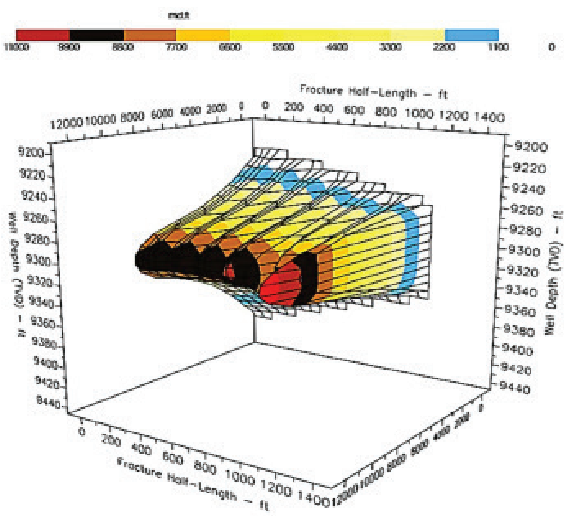

Fig. 7 Fracture conductivity contour.

The simulation results show that the hydraulic fracture penetrates 85 ft downward into the lower sublayer and 75 ft upward into the upper sublayer with a total fracture height of about 193 ft. Still, there is no crossing the base shales to the upper and lower layers. Therefore, the selected interval is a good candidate for hydraulic fracturing treatment.

Conclusions

A geomechanical model of Asmari Formation in an oil well in the south-west of Iran was presented by the use and integration of geological and petrophysical information. Petrophysical properties such as gamma-ray, density, porosity, shale volume, and velocity of the sonic compressive wave were derived from logging data. Poisson's ratio, sonic shear wave velocity, Young's modulus and uniaxial compressive strength were estimated using the empirical relationships. In the next step of building a geomechanical model, the magnitude of three principal stresses were determined using the density logs and new stress polygon formulation. The stress map indicates normal faulting stress area. Principal stresses are lithology-dependent and a shaly layer has a higher minimum horizontal stress than that in other sedimentary rocks. Therefore, uncontrolled height is likely in the shale layer during hydraulic fracturing operations because there is often no stress-barrier in the margin of the shale layers. This leads the hydraulic fractures to propagate out of the target formation. Ultimately, according to this study, it is found out that for confronting this phenomenon, a shaly sublayer interval with lower in-situ stress from surrounding shales should be selected for hydraulic fracturing treatment, and simulation results show that the selected interval is a good candidate. Hydraulic fracture height is controlled and does not cross the base shale of Asmari Formation.

Nomenclatures

ϑ_d = Dynamic Poisson's ratio, dimensionless
V_p = Compressional wave velocity, m/s or km/s

V_s= Shear wave velocity, m/s or km/s
E_s= Young's modulus, Gpa or Mpa
UCS= Uniaxial compressive strength, Mpa
Δt_c= Compression wave travel time, µs/ft
T_0= Tensile strength, Gpa or Mpa
S_v= Vertical stress, psi
S_H= Maximum horizontal stress, psi
S_h= Minimum horizontal stress, psi
α= Biot's constant
ε_x= Strain in S_h direction, dimensionless
ε_y= Strain in S_H direction, dimensionless
P_{bd}= Breakdown pressure, psi
P_p= Pore pressure, psi

Acknowledgments
The authors appreciate the National Iranian South Oil Company for sharing technical data with us during the course of this research.

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