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Selecting perforation intervals and stimulation technique in the Khuff reservoir for improved and economic gas recovery

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Abstract

Saudi Aramco has initiated an acid fracturing program to treat the carbonates of the Khuff reservoir in the Ghawar field in the eastern province of Saudi Arabia. Khuff reservoir belongs to the Permian age and is encountered at an average depth of about 11,500 ft. Two main producing intervals of this reservoir, Khuff B and Khuff C, have tested high quantity of condensate-rich gas.

Khuff reservoir consists mainly of dolomite and limestone sections with streaks of shale and anhydrite that constitute the nonpermeable and possible fracture barrier zones. The reservoir extends up to several hundred feet in thickness with varying quality and production potential. A careful planning of completion technique and choice of stimulation is important for efficient fracture coverage and improved hydrocarbon recovery. This paper addresses the general methodology of selecting perforation intervals and stimulation technique to develop and enhance production in the Khuff carbonate gas reservoir.

Keywords: Perforation intervals; Stimulation technique; Khuff reservoir

1. Introduction

Well stimulation technology has proven to be successful in improving hydrocarbon recovery (Gidley et al., 1989). Many wells are routinely stimulated to increase productivity and recovery. Saudi ARAMCO has initiated an ambitious fracturing campaign to acid-treat the Khuff carbonate reservoirs in the Ghawar field. Matrix acid treatment or acid fracturing is used where the acid reacts with the rock, etches the formation/fracture walls, and creates a conductive path from the reservoir to the wellbore. Acid treatments conducted thus far have resulted in very encouraging gas rate and well productivity. In this paper, we will discuss the (a) preferred stimulation type, (b) correct choice of perforation section, and (c) stages required for a proper treatment to maximize gas recovery in the most economic fashion. Actual field examples are provided to show the results obtained from fracturing.

2. Stimulation techniques

Stimulation treatment is carried on a carbonate reservoir either using (1) Matrix Acidizing or (2) Acid Fracturing. In any event, the reservoir flow and mechanical properties dictate whether a particular treat-

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ment is preferred over the other. To successfully develop reservoirs, correct values of formation permeability, skin damage, and initial reservoir pressure are needed. A pre-fracture test is sometimes recommended which may indicate that a particular reservoir requires no acid fracturing due to the high skin damage replaceable by a modest matrix treatment. A reservoir that has a water contact close to the producing interval and does not have a fracture growth barrier between them may not be treated with acid fracturing. A high permeability reservoir may not substantially benefit from an acid fracture treatment; rather a near wellbore cleanup with matrix acidizing may be adequate.

If a reservoir qualifies for an acid fracturing treatment, the immediate need is to calculate if the entire reservoir can be covered by one treatment or that the treatment should be divided into two or more subtreatments to cover parts of the reservoir separately. This selection of acid stages depends on the reservoir properties and how the reservoir interval is perforated. Both reservoir properties, particularly the mechanical properties, and perforation placements will dictate the geometry of the fracture and thus, it becomes important to perform sensitivity studies on some critical parameters to design an optimal treatment. The next section summarizes some of the critical parameters and their impact on fracture geometry.

3. Reservoir data

3.1. In situ stress

The most important mechanical property that needs to be characterized is the in situ stress profile. In situ stress impacts mainly on fracture vertical and lateral growth and shapes the overall fracture dimension (Rahim et al., 1998; Holditch and Rahim, 1994). Several methods can be applied to calculate in situ stress profile. The most common method is acoustic log-based where the equation that correlates the rock elastic property with the reservoir pressure and tectonics is used as given by the following relationship (Al-Qahtani and Rahim, 2000).

$$\sigma_x = \underbrace{\frac{v}{1-v}P_{\mathrm{OB}}}_{\text{Rock}} - \underbrace{\frac{v}{1-v}A_{\mathrm{V}}P_{\mathrm{P}} + A_{\mathrm{H}}P_{\mathrm{P}}}_{\text{Fluid}} + \underbrace{\frac{Y_{\mathrm{static}}}{1-v^2}E_x + \frac{vY_{\mathrm{static}}}{1-v^2}E_y}_{\text{Tectonic}} \tag{E1}$$

Where, σ_x = minimum horizontal in-situ stress; v = Poisson's ratio; P_{OB} = overburden pressure; P_{P} = pore pressure; A_{V} = poro-elastic constant in the vertical direction; A_{H} = poro-elastic constant in the horizontal direction; Y_{static} = Young's modulus; E_x = strain in the minimum horizontal direction; E_Y = strain in the maximum horizontal direction.

Pressure gradient, p, can be measured from transient tests or from offset well measurements. Tectonic stress, σ_E, will have great impact on in-situ stress for a tectonically active area. v is the Poisson's ratio and is calculated from long-spaced acoustic logs.

The other method is to calculate in situ stress properties on the core samples in the laboratory. However, the most dependable method of calculating in-situ stress is in the field by performing minifracture treatments where fluid is pumped at a rate to barely create a fracture and the pumps are shut down thereafter to measure the initial pressure drop (ISIP) and pressure drop with time. Nolte's analysis or history matching technique is then used to determine fracture closure.

3.2. Young's modulus

Young's modulus describing the stiffness of the rock is an important property that impacts fracture geometry. Narrow fractures are induced in formation with high modulus, whereas wide fractures are created in low modulus formations. Young's modulus can also be determined from logs or from laboratory experiments on cores. High modulus values create tall fractures and thus the treatment design must be carefully done to avoid possible breakthrough into undesired intervals.

3.3. Formation permeability

The permeability dictates the efficiency of gas flow within a reservoir interval and thus is an important factor to consider for the design of a stimulation treatment. High permeability formations are more susceptible to formation damage during drilling and may only require a matrix acid treatment for cleanup. Long fracture is required to effectively treat a low to moderate permeability reservoir as opposed to a short and conductive fracture for a high permeability reservoir.

3.4. Reservoir pressure

Reservoir pressure affects the volume of hydrocarbon reserves and the cleanup of fracturing fluids after the treatment. The choice of fracturing fluid and also the success of a treatment can largely depend upon the reservoir pressure.

3.5. Fluid leakoff coefficient

The total fluid loss coefficient is approximated with the following equation.

$$C_{\mathrm{t}} = 0.047\left(\frac{\Delta p \phi k}{\mu}\right)^{0.5} \tag{E2}$$

where C_{t} is the total fluid loss coefficient and Δp is the net pressure in the fracture. Better reservoir quality (porosity, permeability, pay thickness) increases fluid loss and careful use of additives is required to maintain efficiency. The best method to compute C_{t} is through history matching minifracture treatments prior to pumping the actual treatment.

4. Field examples

The following section illustrates three field (Gas Reservoir Management Division Internal Documentation, 2000) cases for Khuff C carbonate gas producers. Selections of perforation intervals, stimulation method, and post-fracture evaluation have been detailed for certain cases.

4.1. Gas well example 1

4.1.1. Reservoir data

Fig. 1 presents the reservoir flow and mechanical properties for GW-1 well within the Khuff carbonate reservoir. The left column presents formation lithology where the presence of calcite, dolomite, and anhydrite is seen. The geomechanical properties such as Young's modulus and in situ stress are presented in the next column. All geomechanical properties are calculated using open-hole log data, Eq. (E1) and calibrated values of the coefficients. The column next to geomechanical properties indicates residual gas, movable gas, and the total porosity calculated by the open-hole logs. The rightmost column presents the electrical properties measured within the reservoir interval.

The entire Khuff C section is divided into an Upper Khuff C consisting of C1, C2, and C3 intervals and a Lower Khuff C consisting of C4, C5, and C6 intervals. These divisions are artificial and based on the porosity and in situ stress differences to allow detailed calculations in terms of mechanical properties, fracture coverage, and incremental production.

4.1.2. Perforation interval selection

Table 1 presents the different scenarios investigated in selecting the perforated intervals. Scenario 1 is a single-stage treatment with equal perforation shot density in all intervals. In Scenario 2, a limited entry perforation technique is investigated where fewer shots have been placed in the Upper Khuff C intervals. For both these scenarios, the dominant fracture was created in the upper intervals. Particularly for Scenario 1, very little lateral penetration of etched fracture was achieved in the lower Khuff C5 and C6 intervals.

Scenario 3 represents a two-stage treatment where the lower Khuff interval is treated first. The second treatment was directed toward the upper intervals by isolating the lower intervals. By carefully designing the treatment volumes, injection rate, and pad/acid sequences, the fractures could be restricted mostly within the initiation intervals. This scenario generated the best results in terms of zonal coverage and lateral penetration. Fig. 2 presents the normalized fracture half-length as functions of the different treatment scenarios.

It is important to notice that poor lateral coverage is achieved in the Lower Khuff C intervals when the entire reservoir is treated with a single-stage acid treatment (Scenario 1). This is due of the fact that Khuff C2 and C3 intervals take large volume of pad and acid due to their better reservoir quality and lower in-situ stress. Scenario 2 has a better chance of covering the Lower Khuff C intervals because of the limited fluid entry technique used to divert fluid to Lower Khuff C intervals.

As can be seen from Fig. 2, fracturing Upper and Lower Khuff C intervals separately assures the best coverage of the entire Khuff C reservoir. Initial design also shows that the higher stress between Khuff C3

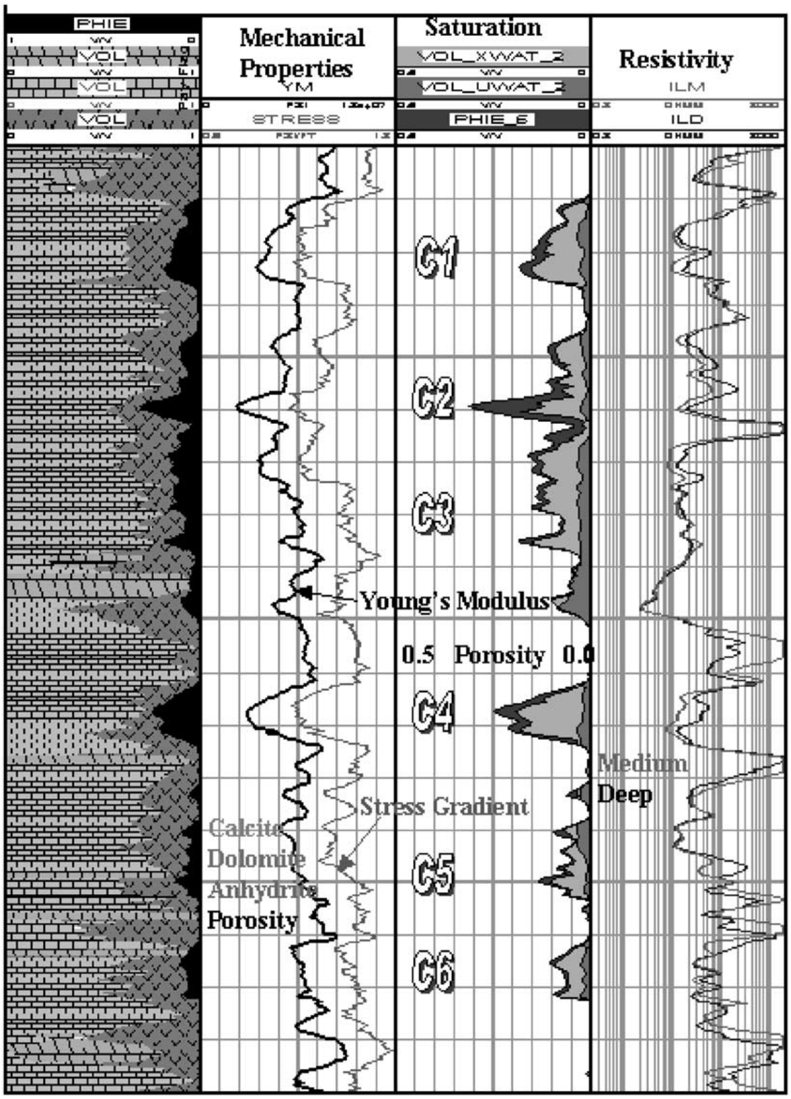

Fig. 1. Reservoir rock properties For GW-1.

and C4 will restrict fracture growth, and thus, there will be little interference among the fractures when the Upper and Lower intervals are treated separately.

The production forecast also indicates that a better rate can be obtained if conductive hydraulic fractures are present in the Lower Khuff C intervals as well. Fig. 3 presents a 10-year forecast with and without fracture treatment as well as with a scenario where only the Upper Khuff C is treated while the Lower Khuff C interval does not get treated (as maybe in a single-stage treatment). Such production forecast shows the importance of effectively fracturing and etching all potential gas bearing intervals so as to maximize recovery. The example thus shows the need of carefully selecting the perforation intervals and the necessity of acid fracturings for improved gas rate.

4.1.3. Fracture pressure match

Calibration tests (datafrac or minifrac treatments) were performed in both upper and lower Khuff C intervals. By matching the actual pressure data with a 3D fracture simulator (Meyer et al., 2000), the stress

Table 1
Perforations within reservoir interval, GW-1

Khuff	Perforation intervals		Perforation scenarios			
	Top, ft	Bottom, ft	1	2	3	
C1	11,420	11,436			×	
C2	11,444	11,463	×	×	×	
C3	11,463	11,488			×	
C4	11,512	11,524	×	×		×
C5	11,538	11,544	×	×		×
C6	11,560	11,572	×	×		×

profile was verified and fluid leakoff was calculated. Figs. 4 and 5 present the minifracture matches for the upper and lower Khuff C intervals. The plots present the measured pressure, the calculated pressure match, and the pumping rate. The calibration tests included step rate tests to measure fracture initiation pressure and near wellbore friction loss due to tortuosity and perforations.

4.1.4. Post-fracture production

Fig. 6 illustrates the etched fracture geometries obtained in the Khuff C intervals along with the geomechanical properties, porosity profile, and production log analysis results. The different shades in the etched region are indicative of fracture conductivity, going from the highest near wellbore to lower values toward fracture tip. An acceptable conductivity value of around 5,000 md-ft will provide an effective average fracture half-length of about 150 ft in the producing intervals. Fig. 6 also presents the production rates from a PLT measurement performed after the acid treatment indicating contribution from all net pay intervals.

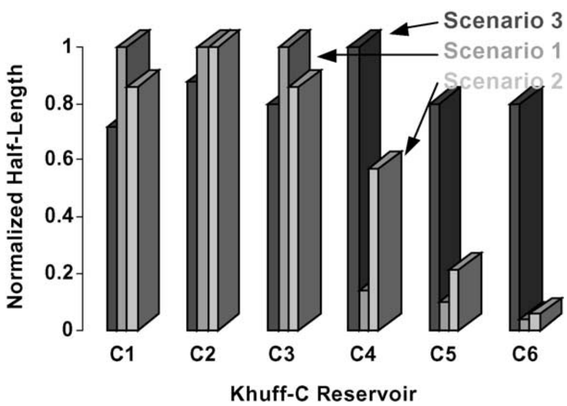

Fig. 2. Normalized half-length for various completion scenarios, GW-1.

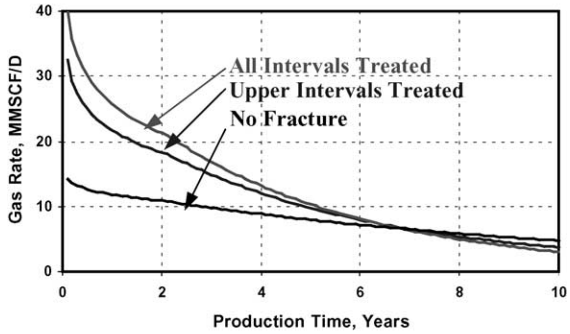

Fig. 3. Expected production for different perforation scenarios, GW-1.

The production contribution from each zone is also presented in Fig. 7. The left y-axis presents gas rate in MMScf/D and porosity in percentage. Although the fracture has effectively covered both Upper Khuff C and Lower Khuff C intervals, the production log attributes most of the production to the Upper Khuff C (Fig. 6). This is because the Khuff C2 and C3 intervals, which are connected without any nonpay sections separating them, have the best permeability thickness product and therefore dominate the initial flow of the reservoir. It is expected that the other intervals will also contribute to the gas flow and will support in maintaining long-term well productivity.

4.2. Gas well example 2

GW-2 well is drilled in the Khuff reservoir where the permeable section is encountered within three

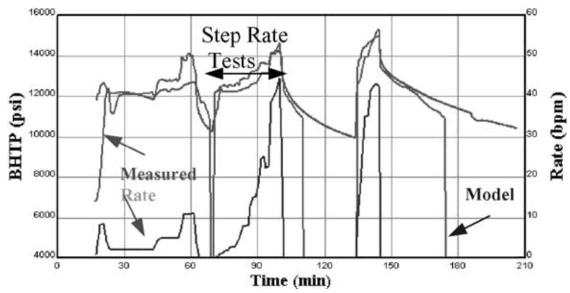

Fig. 4. Minifracture match for lower Khuff C interval, GW-1.

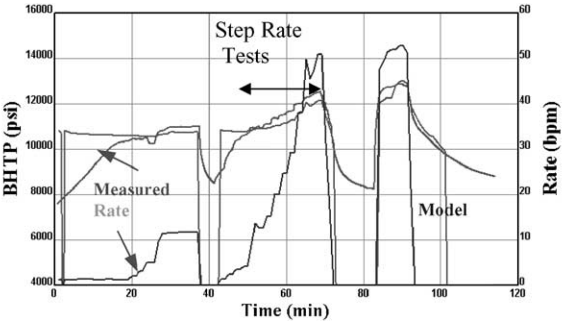

Fig. 5. Minifracture match for Upper Khuff C interval, GW-1.

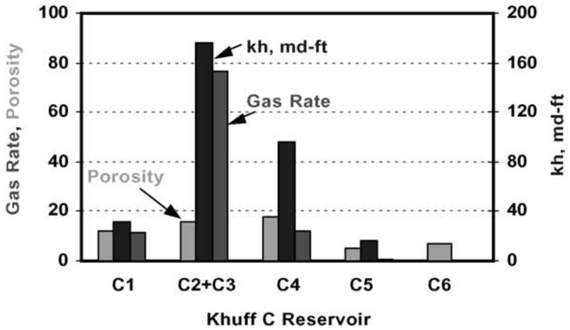

Fig. 7. Production contribution from the Khuff C intervals, GW-1.

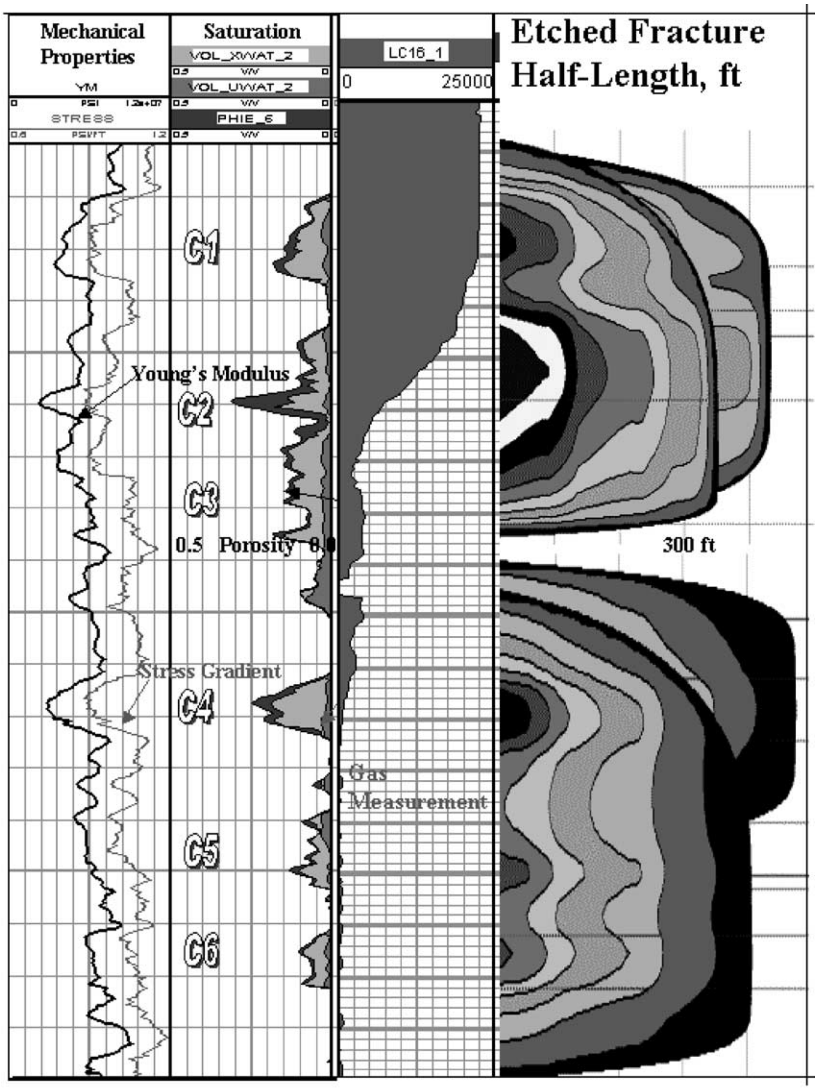

Fig. 6. Fracture growth and post-fracture production, GW-1.

distinct sections as indicated in Fig. 8. The reservoir data presented in Fig. 8 show excellent porosity development in the lower section where the porosity reached 25% with an average porosity of over 15%. The corresponding estimated average permeability on the order of 1.5 md. The fracture dimensions achieved from the design runs are also presented in the figure along with the formation mechanical properties.

Different perforation scenarios were studied to compute fracture vertical and horizontal coverage. Fig. 8 presents the lithology, geomechanical properties, and saturation/porosity profiles obtained from open-hole logs. Also presented is the etched fracture geometry obtained by perforating Upper, Middle, and portion of Lower Khuff C intervals. Fractures initiated in this scenario automatically grow and cover all lower Khuff C interval because of non-existence of high stress barrier in the pay zones. The etching of Lower interval is also enhanced due to the better reservoir quality and lower in situ stress in this region.

When Lower Khuff C interval is also perforated and fracture is initiated simultaneously into all three

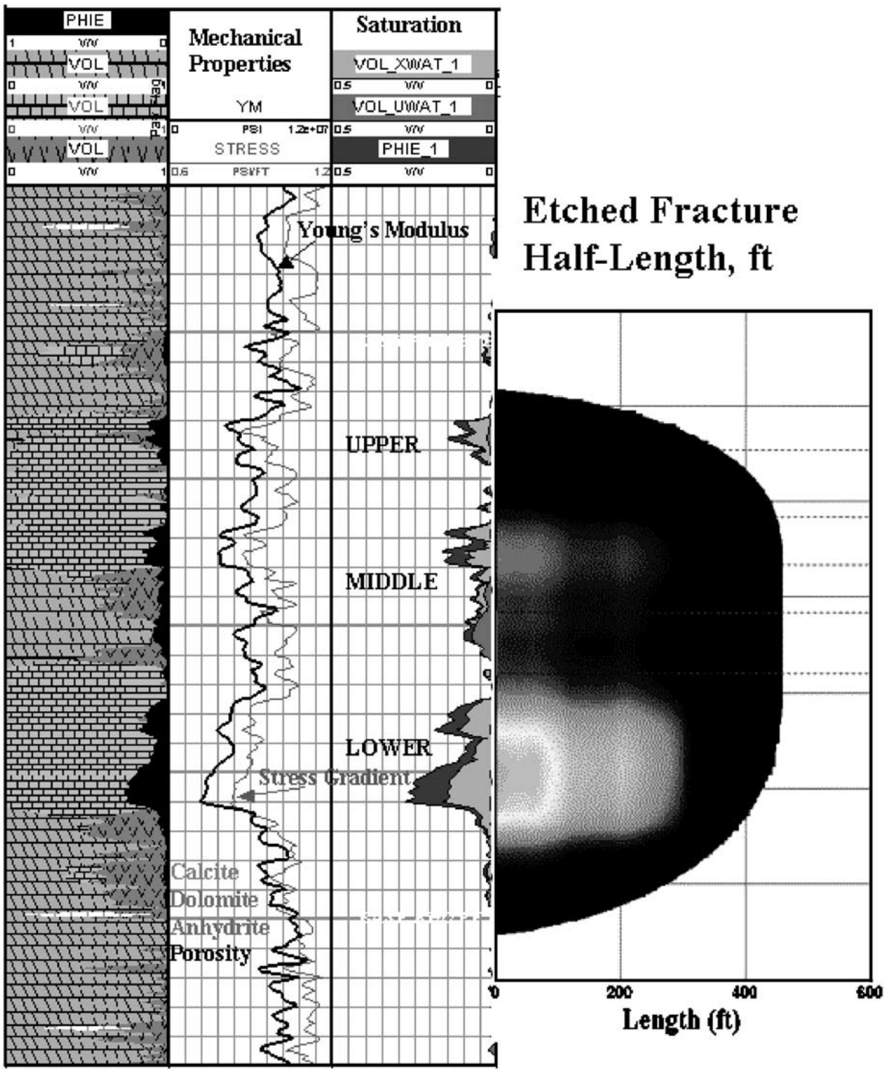

Fig. 8. Reservoir properties and fracture profile, GW-2.

Table 2
Perforations within reservoir intervals, GW-2

Reservoir intervals, depth in ft	Perforation scenarios			
	1	2	3	4
C1: 11,680–11,694	×	×		×
C2: 11,703–11,711				
C3: 11,715–11,730	×	×		×
C4: 11,745–11,764	×	×	×	
C5: 11,776–11,788	×		×	×
C6: 11,790–11,814	×		×	×

intervals, the upper intervals, particularly Upper Khuff C does not receive much treatment. This is because acid preferentially flows into and etches the better zones it encounters first (Lower interval) and tends to bypass intervals of relatively lower quality.

Some of the possible scenarios that were investigated during the design run are summarized in Table 2.

Fig. 9 presents the etched fracture half-lengths obtained for the various perforation scenarios given in Table 2. The values for each interval (fracture length and conductivity) are calculated by running fracture simulation model for each Khuff interval with specific reservoir properties. The calculated values are plotted as function of reservoir intervals. As can be seen from this figure, Scenario 2 treatment will cover all pay sections of the reservoir most effectively. Scenario 2 was thus selected as the perforation strategy for this well.

The possibility of conducting a two-stage treatment has not been investigated. However, it is obvious that any treatment directed toward the Upper and/or Middle section (e.g. Scenario 2) will stimulate Lower Khuff C as well due to the low in situ stress in this interval. Once the acid penetrates Lower Khuff C, it is very difficult to achieve any further fracture length in the two upper sections. The average length of 100 ft of etched fracture obtained in the Upper and Middle Khuff C is possibly the most that can be achieved in such reservoir intervals. A 10-year gas production forecast from the individual reservoir intervals due to fracture treatment is presented in Fig. 10. The cumulative production forecast is presented in Fig. 11. These calculation shows the importance of achieving as much acid coverage as possible in all pay zones.

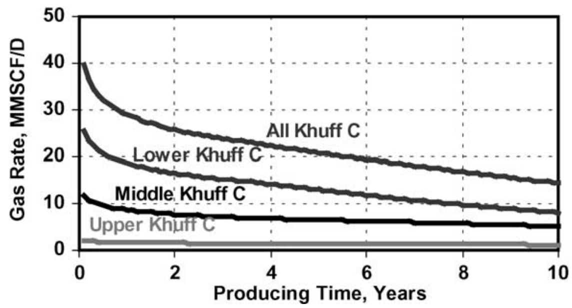

Fig. 10. Gas rate contributions from Khuff C intervals, GW-2.

4.3. Gas well example 3

Reservoir properties for the well GW-3 are presented in the formation log provided in Fig. 12. The formation log provides the lithology, fluid saturation, and core permeability measured in the laboratory. The net interval is about 70 ft and the reservoir flow properties are outstanding. Based on the reservoir characteristics, a production forecast was run to see the benefit of the fracture. Fig. 13 presents long-term production forecast for GW-3 well. The figure shows production comparison between a no-fracture, non-

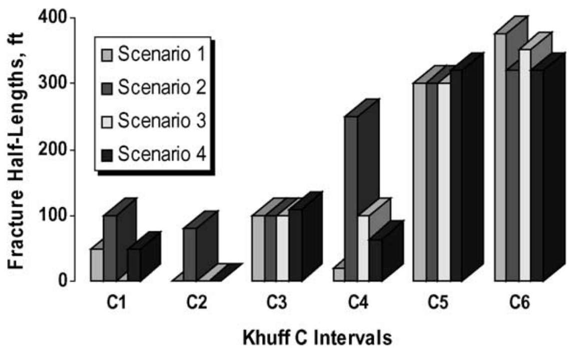

Fig. 9. Fracture length for various perforation strategies, GW-2.

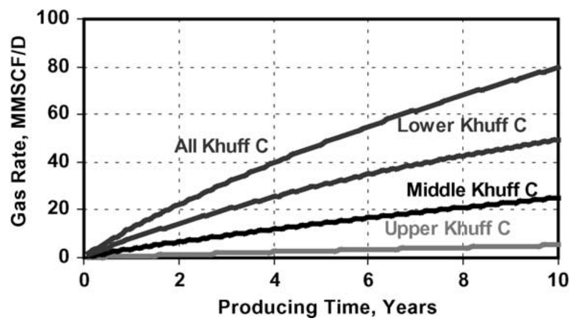

Fig. 11. Cumulative gas contributions from Khuff C intervals, GW-2.

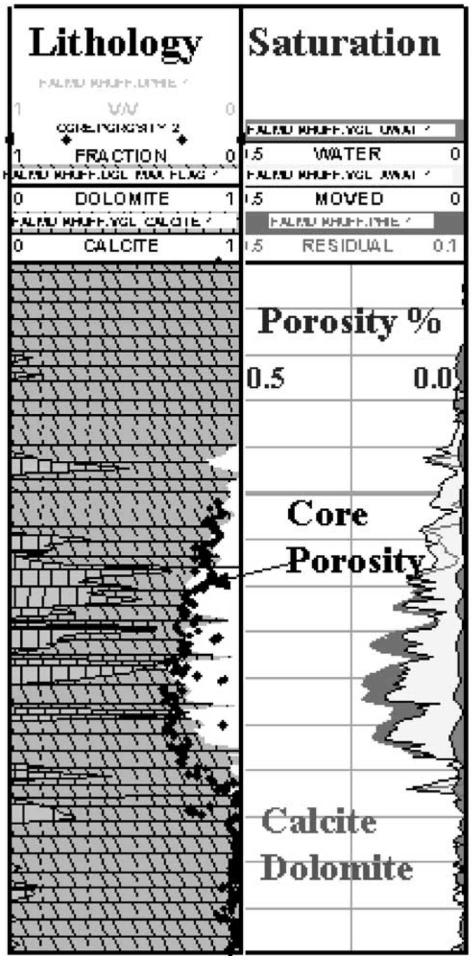

Fig. 12. GW-3 Reservoir profile.

damaged reservoir and a 70-ft fracture case. For reservoir qualities as we encounter in GW-3 with low stress and high flow capacity, it is very difficult to achieve an etched and conductive fracture half-length of over 100 ft.

Based on the reservoir quality and production performance, it was concluded that fracturing the well will not improve the performance of the reservoir significantly. Such reservoirs are usually matrix acidized rather than fractured to remove near wellbore skin damage and enhance near well formation flow capacity.

5. Sensitivity runs

Any reservoir must be carefully studied to correctly choose the stimulation method. If this is not the case, a reservoir may still be stimulated using a certain method (as in the case of GW-3 well by choosing acid fracturing over matrix acidizing), but it may not necessarily be economical. Also, attempt to inducing hydraulic fracture in high permeable intervals will damage the formation due to excessive leakoff. In such cases, simple matrix acidizing is the best method of stimulation.

Fig. 14 presents two sensitivity runs where reservoirs with 10- and 50-md permeability have been acid fractured, each with a 100-ft etched fracture. We notice how the incremental long-term production depends highly on reservoir quality (Fig. 14). The better the reservoir quality, the lesser is the need to implement a fracture treatment. For higher quality reservoirs, matrix-type treatments to remove near wellbore damage caused by drilling and completion

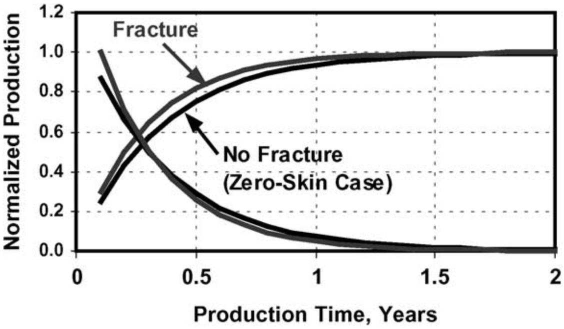

Fig. 13. Long-term production forecast, GW-3.

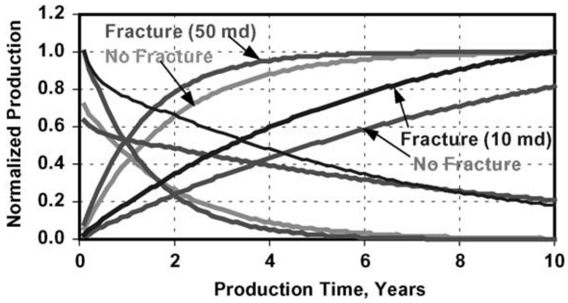

Fig. 14. Long-term production for various reservoir qualities.

fluids are adequate to restore production and should be considered as viable alternatives to fracturing.

6. Conclusions

The following conclusions can be drawn from the study.

(1) A careful evaluation of the reservoir layers is important to successfully design a fracture treatment and chose the correct stimulation type.
(2) If the pay section is heterogeneous, large, and not continuous, selectively choosing the perforation interval may provide better coverage for the treatment. Perforations can be added after fracturing if needed to provide more open area from the reservoir to wellbore.
(3) The better quality zones usually have a tendency to absorb much of the fracture fluid and stimulation acid. Thus, the most conductive fracture is generally initiated and propagated in such sections. If these intervals are perforated and treated simultaneously like other sections, the relatively lower quality sections may not get adequate treatment.
(4) A multi-stage treatment is recommended if the stresses that exist in-between sections are adequate to prevent vertical fracture growth. A single-stage treatment is recommended over a multi-stage treatment if potential intervals can be covered by single-stage without sacrificing much of fracture length or conductivity.

Nomenclature

C_t	Total fluid-loss coefficient, ft-$\sqrt{\text{min}}$
k	Permeability, md
ΔP	Net pressure inside fracture, psi
P	Pressure, psi
ϕ	Porosity, fraction
μ	Viscosity, cP
σ_T	Tectonic stress gradient, psi/ft
σ_x	Minimum horizontal stress gradient, psi/ft
σ_z	Overburden stress gradient, psi/ft
v	Poisson's ratio

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