Performance Evaluation of Horizontal Wells in a Tight Carbonate Reservoir
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Abstract
This paper presents a case study of evaluation of the performance of horizontal wells drilled in a tight carbonate reservoir in Kuwait. Successful wells were those that intercepted natural fractures. A methodology was developed to define the reasons for the performance of horizontal wells. The methodology involved use of geological, petrophysical, geochemical, transient test, rock, and fluid properties to develop a numeric simulation model. Conclusions regarding well performance were made by using a newly developed analytic simulator and the numeric model.

While the analytic simulator provided rapid rate forecasts, the numeric simulator gave insights into the causes for unsatisfactory well performance. For example, well placements within the bed, low-permeability rock, and unfavorable relative permeability characteristics all contribute to the rapid rate decline and the associated increasing gas/oil ratio (GOR) production. We proposed cyclic production and oil injection-production schemes to address the high-GOR production problems. In the first scheme, a well is produced and shut-in in an alternating fashion to preserve the reservoir energy. Oil is injected for a very short duration to alleviate the near-wellbore gas saturation problem in the second scheme. In both cases, the high-GOR production is minimized and the ultimate oil recovery is improved.

Introduction
Horizontal well technology has evolved rapidly since pioneering drilling efforts were begun in late 1970's in the Raspo Mare Field offshore Italy. In the US, spawned by successes at the Austin Chalk formation in East Texas since 1985, the horizontal drilling activity gained considerable momentum. Austin Chalk\textsuperscript{1} happens to be a tight carbonate with extensive vertical and sub-vertical fracturing. Despite publication of numerous successful case histories, Beliveau\textsuperscript{2}, while compiling a major operator's world-wide horizontal well efforts, observed that many-fold production increases do not often materialize because of incomplete knowledge of reservoir heterogeneity before drilling. North Sea's Ness field\textsuperscript{3} is also a case in point.

Combined industry experiences suggest that the success of horizontal wells lie in selecting the right candidate reservoir. Fayers et al.\textsuperscript{4} summarize some of the reservoir engineering issues that need considering while evaluating horizontal well prospects.

Besides gaining productivity increases in general, horizontal wells have enjoyed successes in combating coning or cresting of water and/or gas, in accessing by-passed oil\textsuperscript{5-6} and multiple flow units\textsuperscript{7}, and in converting resource into reserves, such as those in heavy oil\textsuperscript{8,9} and tight reservoirs\textsuperscript{10}. Examples of high-permeability sandstone reservoirs where water coning has been mitigated include Troll field\textsuperscript{11} in the North Sea, Prudhoe Bay field\textsuperscript{12} in Alaska, Safaniya field in the Middle East, and those in offshore west Australia. Similarly, horizontal wells in Rospo Mare\textsuperscript{13}, the Karsted limestone reservoir, have enjoyed considerable success in mitigating water coning. While horizontal well successes are often presented in various forums, the associated failures do not gain as much publicity. Generally speaking, occurrences of failure are high with carbonate reservoirs where successes depend largely upon horizontal wells intercepting natural fractures.

South Kuwait's Mauddud reservoir in discussion is a low-permeability carbonate with sparse fracture development. Successful exploitation of reserves with horizontal wells in similar reservoirs has not been reported. Only the Dan field\textsuperscript{10} in the North Sea and the Kharib B reservoir offshore Qatar have permeabilities that are comparable to this reservoir, that is, 1 to 10 md. However, they are much thicker and lend themselves to hydraulic fracturing because of confining shale barriers. Besides accessing fractures, the fluid-rock interaction with changing fluid saturations plays a critical role in the success of long-term producibility potential of a well. Thus, initial screening criteria should encompass this...
aspect before drilling horizontal wells.

In this paper, we present an approach for understanding the reasons for less-than-satisfactory performance of many horizontal wells. All the tools of a multidisciplinary team were brought to bear to study the underlying problems. Our intrinsic idea was to translate the lessons learned from this reservoir into a working principle so that other opportunities are identified correctly.

Reservoir Characterization

Geological. Maudud formation's geological age is Middle Cretaceous and it occurs with low structural relief throughout Kuwait. The Maudud constitutes a sequence of dominantly carbonate and minor clastic sediments that occur pervasively throughout the region of the Arabian Gulf. This formation in Kuwait conformably overlies the Burgan formation but contacts the Wara formation above on a less conformable basis. Deposition of Maudud forming sediments occurred mostly in very shallow waters, according to Al-Shamlan et al.,14 who studied the Maudud extensively in the Greater Burgan area. Depositional environments identified by their work include shelf lagoons, ponds and tidal flats. However, transgressive sediment accumulation was interrupted twice, the first and minor event resulted in isolated argillaceous facies within the Maudud.

Maudud lithology is principally limestone in the Greater Burgan area. Al-Shamlan et al.14 proposed a hierarchical division of the Maudud into six depositionaly related facies. Of the six facies, the bioclastic is the most common because it exhibits the most occurrences of lateral and vertical continuity. Other facies, where they occur, have limited lateral extent and have not been observed in boreholes to compose a total vertical section. Thicknesses of the Maudud formation in Greater Burgan are relatively thin, ranging approximately from 18 to 70 ft. In the study area, the average thickness is about 44 ft.

We found that fracture porosity most frequently occurred in the bioclastic facies, commensurate with the previous work.14 Furthermore, based on core analyses, permeability is best in the upper portion of the Maudud and generally degrades severely going down in the section. Core evaluation also indicates that fractures occur predominantly in the upper portions of the Maudud section. The general trend of the axes of these fractures is northeast-southwest as determined from measurements in boreholes and oriented cores. Figure 1 displays the structure map and fracture trends on some of the cored wells. Faults cut in the Maudud are infrequent in the study area: faults are normal and appear to have throws of no more than 12 meters. Thrors of most faults encountered are about 10 ft and their orientation appears to oppose the trend of natural fractures.

The Maudud does not contain a water leg in the study area. In terms of reservoir quality, this formation is tight (low porosity and permeability), except for the upper portion of the Maudud bioclastic facies. Geological factors of the Maudud most pertinent to the success of horizontal wells in the Greater Burgan area are thus: flat lying structure; relatively very thin section; continuity of the bioclastic facies; occurrence of fractures and highest permeability in the upper section.

Petrophysical. The primary objective of evaluation of wireline logs was to distinguish fractured intervals from those not fractured. This evaluation provided a basis for selecting individual methods of analyses for reservoir properties in fractured and unfractured formation. Core and log data were used for analysis of reservoir properties and their variations.

Responses of some common logs, such as gamma ray, density, and neutron porosity are remarkably distinct in horizontal boreholes, drilled through the fractured Maudud formation. Resistivity measurements, among others, were also made during and after well drilling. Borehole imaging, acoustic, and nuclear logging were the most useful for fracture characterization. Semi-quantitative analyses of fracturing were possible when the log data were combined with analyses of core samples. We determined orientation, frequency, and nature of fractures by quantitative work on oriented cores from vertical pilot boreholes.

Accurate but qualitative identification of fractured Maudud formation is possible with only conventional nuclear logs. Core studies and interpretation of borehole image data indicated that the nature of fractures in the Maudud formation ranged from open to filled by mineralizations. This information combined with observations of gamma ray (GR) spectrometry measurements strongly suggested that levels of concentrations of a Uranium decay product (U), present in healed and partially healed fractures, are elevated above concentrations of U existing in unfractured Maudud formation.

Figures 2a and 2b show GR spectrometry measurements over 46 ft along a horizontal section. Two traces, in API units for GR spectrometry data, appear in the figures as GR' and GR. GR' was derived from GR by subtracting out the detector responses to U. Relatively large separation of GR' from GR traces on well logs is indicative of fractures. Figure 2b was recorded in an interval that is not naturally fractured.

Bulk density (BD) and neutron porosity (NP) log trace signatures coincide with gamma spectrometry logs, with respect to fracturing. Properties of unfractured Maudud formation were taken as representative of the matrix. The average porosity by BD and NP measurements in fractured intervals is only somewhat greater than in unfractured intervals. The sections of BD and NP logs shown in Figs. 3a and 3b are from the same interval as the GR logs shown above. BD units are grms per cubic centimeter and NP units are limestone freshwater porosity. The dynamic range of BD and NP values are the greatest throughout fractured intervals of the Maudud formation, as shown in Fig. 3a.

Acoustic logs run in most Maudud horizontal holes had a
dipole source that generate acoustic waves at shear wave velocities. We processed acoustic data to show interference patterns for detecting fractures. Interference patterns do not develop in absence of fractures, however. Figures 4a and 4b are well log presentations (46 ft) of the acoustic data processed in fractured and unfractured Maudud formation, respectively. These interference patterns are consistent with the nuclear data, thereby eliminating other sources clouding the issue.

The main observation from the petrophysical analysis is that fractures can be identified without borehole imaging. **Transient Testing.** Performance of horizontal wells had been mixed in this tight reservoir. The first well showed about five-fold productivity gain to about 2,000 STB/D, but many drilled thereafter did not meet expectations. Good performance of a few Maudud wells was thus speculated to be the result of communication with the underlying Upper Burgan sandstone reservoir through natural fractures.

To evaluate the suspected vertical communication, we designed and implemented a multwell pressure-transient test (pulse test) program between a horizontal producer and offset Burgan producers. This communication test was critical to assess further horizontal well drilling campaign in this carbonate reservoir. Figure 5 depicts the wells involved in the pulse test, which was conducted in three phases. Figure 6 captures the entire sequence of events and pressure response in both vertical and horizontal observation wells.

**Phase 1.** In the first phase, the Upper Burgan producers (P-1, P-2, and P-3) were pulsed for a total cycle of 144 hours with 72 hours flowing (total rate of 5,520 STB/D) and 72 hours shut-in periods. Pressure was observed in horizontal Maudud well, O-1, and in the vertical Upper Burgan producer. O-2. Both the vertical and horizontal observation wells were shut-in for six days before the onset of pulsing cycle. The pressure response in the horizontal well (O-1) reflects normal pressure buildup. The data show no evidence of any sinusoidal response, thereby, indicating no vertical communication between the Maudud and Upper Burgan reservoirs. In contrast, a clear response is observed at the vertical well, O-2, owing to the combined effects of the pulsing cycles of the Upper Burgan producers. Thus, good communication between the pulsed wells and the observation well, completed in the same horizon, is demonstrated.

**Phase 2.** In the second phase, the horizontal well O-1 was pulsed for a total cycle of 96 hours comprising 48 hours flow at 2,231 STB/D and 48 hours shut-in periods. Pressure response was observed at O-2. During this phase, the Upper Burgan producers were pulsing. Figure 6 clearly shows a good sinusoidal response at O-2 because of pulsing of the Maudud horizontal well. This communication is attributed to O-2 well’s proximity to the horizontal well’s toe and to mechanical problems through poor cement bond and casing corrosion. Cased hole logs provided the corroborative evidence.

**Phase 3.** In the third and final phase, we pulsed the horizontal well O-1 and observed pressure response in P-1. As Fig. 6 shows, there is no evidence of any communication between O-1 and P-1. The sinusoidal variation as evidenced on the plot has a 24-hour cycle, suggesting tidal effects. This phase of the test program further confirms that no communication occurs between the Upper Burgan producers and the Maudud horizontal well.

Based on the qualitative results of the communication tests, we believe that horizontal wells produce from the Maudud formation and there is no inter-reservoir vertical communication. This conclusion is supported by the results of the geochemical fingerprinting analysis done on samples drawn from two of the five wells in question, as shown in Fig. 7. Recently, Kaufman et al. discussed details of the fingerprinting analysis in this field.

**Single-Well Modeling**

Understanding reservoir fluid flow was the first step toward diagnosing the problems associated with less-than-satisfactory performance of many Maudud horizontal wells, specially those that have not intercepted any fractures. We conducted single-well simulations to understand the mechanics of reservoir fluid flow. Both analytic and numeric approaches were used. Initially, the analytic method provided some clues about a well’s productivity potential in this tight, solution-gas drive reservoir. To gain further insight, we used a numerical simulator.

**Analytic Approach.** The obvious advantage of the analytic method is its simplicity and the speed of computation. Details of this formulation is described elsewhere in the literature. Briefly, a well is produced at a constant bottomhole pressure, wherein flow periods of infinite-acting, transitional, and pseudosteady-state (pss) are modeled. The method of images is used to compute rates during the transitional and pss flows for bounded reservoirs. Two-phase gas/oil flow is modeled by specifying decline coefficient, which implicitly accounts for the reservoir drive mechanism, relative permeability effects, etc. Figure 8 shows the rapid rate decline and the associated cumulative oil production corresponding to 200, 600, and 1,000 acres. Many other sensitivity parameters were explored but are not reported here for brevity. While analytic simulations gave us a good indication of well performance in absence of fractures, we still needed to learn about the consequences of two-phase flow: gas segregation and migration, rate sensitivity, relative permeability effects, etc.

**Numeric Approach.** We set up a numeric model for a generic 1,500-ft horizontal well to understand flow behavior in an unfractured system. To ensure solution accuracy, only a quarter segment of the reservoir was modeled. A 11x11x5 rectangular grid system representing a reservoir volume of 1125x1125x30 cu ft was used for the study. Top three layers comprised the 10 ft of good pay having a permeability of 10 md. In contrast, the bottom two layers of 20 ft had a
permeability of 1 md. We did some numerical experiments to explore the impact of grid size effects on solution quality.

Figure 9 compares the performance of a horizontal well with its vertical counterpart. As expected, the horizontal well's higher productivity index (PI) translates into its superior performance, initially. However, the rapid rise in the GOR starts to counteract the initial advantage. Figure 10 shows that if the high GOR production can be tolerated, a horizontal well causes an acceleration of reserves. This finding is in accord with the general consensus of a horizontal well's performance in solution-gas drive reservoirs.

In Mauddud, the problem compounds because the well is located, by design, at the formation top to access the fracture network. Because gas segregation occurs owing to the dominating gravity forces, a secondary gas cap begins to form, thereby impairing the oil productivity. The lack of reservoir structural relief implies no gas migration elsewhere. Figures 11 and 12 present the time-dependent gas saturation profiles in each layer for the two well configurations. All the simulation runs were made at 1,000 psia bottomhole pressure or at a drawdown of about 1,000 psi. Although not shown, the well performs adversely when subjected to a larger drawdown of 1,500 psi. We note that recent production tests with a portable separator corroborate the results of these simulations in a semi-quantitative sense.

Rock relative permeability plays a key role in governing the producing GOR in a solution-gas drive system, such as in Mauddud. To examine the sensitivity of this key parameter, we used more favorable relative permeability curves for the 10 to 100 md range permeability. The one used previously represented a 1 to 10 md formation rock. Both sets of relative permeability curves were based on actual Mauddud rock.

Figures 13 and 14 clearly demonstrate the large contrast in well performance with the new relative permeability curves. The high-GOR problem is minimized to a large degree, perhaps explaining the sustained good performance of some of the successful wells. Thus, whenever fractures are intercepted, which, in turn, results in higher effective rock permeability, an improved well performance is to be expected.

Proposed Solution. The preceding mechanistic simulations and others, not reported here, raised questions about effective ways to produce horizontal wells having unfavorable rock characteristics, both in terms of absolute and relative permeabilities. To explore this question, we considered two scenarios: (1) a cyclical production (CP) scheme, and (2) an oil injection-production (IP) scheme. In the cyclical scheme, a well is produced for a certain period and then shut-in to regain reservoir pressure in the well vicinity. In contrast to the well shut-in, oil is injected over a very short time period to restore oil saturation and some pressure in the well vicinity, thereby improving oil productivity in the second option.

Figures 15 and 16 show that the cyclical production scheme clearly outperforms the continuous production mode by conserving and regaining reservoir energy in each cycle. In the cyclical mode, reservoir energy is conserved by reducing the high-GOR problem significantly. We can further improve a well's performance by periodically injecting oil to reduce the gas saturation significantly. In this scheme, cumulative oil recovery is even higher than both the continuous and the cyclical production modes. Figures 17 and 18 capture the essence of these simulations.

Field Pilot Study

We conducted a field trial on a well using the cyclic production scheme. Simulation studies showed an on/off cycle, each period lasting a month, for maximizing the ultimate recovery. Historically, this well has had problems sustaining rates. However, the well trajectory has the desired characteristic of being parallel to the bedding plane, thereby allowing the solution gas to segregate.

Onsite portable separator testing ensured accurate rate data gathering. Figure 19 shows the initial rate and the attendant high GOR when the well was opened in July 1996 after over a year's shut-in. Note that the solution GOR is 566 Scf/STB. Testing the well in September, after a month's shut-in, showed that both the rate and the GOR declined, following the initial increase. Toward the month's end, the well ceased flowing because the wellhead pressure could no longer buck the flowline pressure of 100 psig. We surmised that both the intrinsic low rock permeability and unfavorable relative permeability characteristics could not sustain the well productivity.

In the ensuing cycle when the wellhead pressure turned out to be very low, the shut-in time was increased significantly to study the well behavior. Figure 20 shows the slow rise in wellhead pressure. The well was opened for flow when the wellhead pressure reached 200 psig. Rates measured at the gathering center indicated values around 400 STB/D. The rapid increase in the wellhead pressure signifies high-GOR production and the subsequent rapid decline is indicative of poor reservoir transmissivity.

A long-duration buildup test sheds some light on the rock's inability to transmit fluids efficiently around this well. Figure 21 shows the very slow buildup process, which was dominated by wellbore storage. Indeed, static gradient surveys run periodically indicated a gas gradient down to the measured depth until at least 88 hours as shown in Table 1. Clearly, the large drawdown at the sandface created the gas-filled wellbore.

Table 1 - Time-Lapse Static Gradient Surveys

<table>
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<tr>
<th>Δt, hr</th>
<th>p_w, psig</th>
<th>γ, psi/ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>88</td>
<td>698.8</td>
<td>0.018</td>
</tr>
<tr>
<td>592</td>
<td>1075.1</td>
<td>0.337</td>
</tr>
<tr>
<td>808</td>
<td>1150.1</td>
<td>0.341</td>
</tr>
<tr>
<td>1624</td>
<td>1327.4</td>
<td>0.342</td>
</tr>
<tr>
<td>2760</td>
<td>1440.2</td>
<td>0.342</td>
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</table>
Figure 21 shows that the extrapolated pressure\textsuperscript{17} of 1693 psig is some 253 psi higher than the last measured pressure after 115 days of shut-in. Distributed pressure measurements in the vertical pilot borehole revealed mobility of less than 10 md-ft/psi, thereby confirming unfavorable rock characteristics.

We concluded that this well is unsuitable for the cyclic production scheme. We are now testing other wells that have more favorable flow characteristics because even the best producers have shown signs of increasing GOR and declining rates after four years of production.

Discussion

This study underscores the importance of a multidisciplinary approach before selecting reservoirs suitable for horizontal well drilling. Recent work of Solomon\textsuperscript{18} emphasized some of these issues.

The multidisciplinary approach was extended to study the prospect for well stimulation. We carefully considered improving the well productivity by fracture stimulation before rejecting it. The major problem stems from lack of thick shale barriers. Thus, the probability of confining transverse fractures to the target horizon is very remote. In addition, each wellbore needs to be cased and cemented before attempting any fracture stimulation, leading to a very expensive treatment of questionable value. Perhaps more important, analytic simulations showed that multiple transverse fractures cause marginal gain in cumulative production, because the rate declines rapidly after the initial productivity gain.

We learned a key aspect from this study. Before selecting a candidate reservoir, one needs to investigate both the rock and fluid properties governing the fluid flow behavior. In the Mauddud reservoir, oil is close to the bubblepoint pressure; thus, making it very unattractive for sustained gas-free oil production. More importantly, the gas is likely to segregate to the formation top because the gravity forces dominate the viscous forces in a tight reservoir. Lack of reservoir relief adds further woes to the gas segregation issue. By placing a well at the formation top, because that is where the good porosity development occurs, we jeopardize the well’s oil productivity.

Several screening tools have emerged for selecting reservoirs suitable for horizontal wells. These analytic tools, however, cannot capture either the dynamics of two-phase flow or the gravity effects. Thus, a major lesson learned from the Mauddud experience is that at least cursory numerical simulations are required beyond the initial screening before selecting a target reservoir.

We found both the IP and CP schemes to be attractive for exploiting reserves from a tight, solution-gas drive system, such as the Mauddud carbonate reservoir. These schemes are analogous to forced (IP) and free (CP) convective heat-transfer modes. Our first attempt at testing the cyclic production scheme exposed some of the serious problems with this formation. However, the lessons learned are being used to better engineer the pilot in wells with favorable flow characteristics.

Conclusions

1. A systematic, multidisciplinary effort revealed the reasons for unsatisfactory performance of some horizontal wells in a tight carbonate reservoir. Very low matrix permeability, unfavorable relative permeability characteristics, and well placement within the bed all contribute adversely to production. In south Kuwait’s Mauddud reservoir, horizontal wells must intercept fractures to sustain rates.

2. Numeric simulations, revealing the fluid/rock interplay, are required to evaluate the long-term performance of horizontal wells. However, analytic simulations, as shown here, can be used as initial screening and rapid evaluation.

3. Both cyclical and production-injection schemes appear to improve the ultimate recovery from a tight, solution gas-drive reservoir. However, field experiences showed that very low-permeability reservoirs, in absence of fractures, are not conducive to the cyclic production stimulus.

Acknowledgments

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Nomenclature

\[ P_{sw} \] - shut-in bottomhole pressure, psig
\[ p \] = average drainage-area pressure, psig
\[ \Delta P \] = pressure change, psi
\[ \Delta P' \] = superposition-time-derivative of \( \Delta P \), psi
\[ \Delta t \] = shut-in time, hr
\[ \gamma \] = fluid gradient in wellbore, psi/ft
\[ \sigma \] = standard deviation, psi

References

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Fig. 1 - Map showing the Mauddud fracture orientation in the Greater Burgan area.
Fig. 2a - GR spectroscopy log response identifies fractures.

Fig. 2b - GR spectroscopy log response shows no fractures.

Fig. 3a - Density and neutron porosity logs identify fractures.

Fig. 3b - Density and neutron porosity logs show no fractures.

Fig. 4a - Processed dipole acoustic log identifies fracture interference pattern.

Fig. 4b - Processed dipole acoustic log shows absence of interference pattern.
Fig. 5 - Sectional and plan views of wells involved in pulse tests.

Fig. 6 - Measured pulse test response at various wells.
Fig. 11 - Progressive gas segregation in the horizontal well.

Fig. 12 - Progressive gas segregation in the vertical well.

Fig. 13 - Relative permeability curves strongly influence well performance.

Fig. 14 - Cumulative recovery is governed by relative permeability curves.
Fig. 15 - Cyclic production outperforms the continuous scheme.

Fig. 16 - Reservoir energy is conserved by cyclical production.

Fig. 17 - Production-Injection mode outperforms the continuous scheme.

Fig. 18 - Higher cumulative oil recovery is realized by the production-injection scheme.
Fig. 19 - Measurements show production difficulties.

Fig. 20 - Rapid rise in wellhead pressure signifies high GOR.

Fig. 21 - Obtaining \( \bar{p} \) using buildup and static gradient data.