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## Reservoir Characterization and Infill Drilling Study of a Low-Permeability Carbonate: An Evaluation of Blanket Versus Targeted Infill Drilling Strategies

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### Abstract

This paper presents the methodology and results of a reservoir characterization study of Clear Fork carbonates in the TXL South Unit Field located in Ector County, Texas. The principal objective of our study was to evaluate a targeted infill drilling strategy for future field development. Our study incorporated an integrated approach for which the primary evaluation tool was decline type curve analysis of well production data. The well performance analysis was both supplemented and complemented with petrophysical and geological studies, each representing different reservoir scales. On the basis of our study, we identified areas of the field with the highest reservoir quality and largest oil-in-place volume, thus identifying the areas of the field best suited for infill drilling.

### Introduction

Like most Permian-age carbonate reservoirs in the Permian Basin, Clear Fork carbonates in the TXL South Unit Field are characterized by very thick, heterogeneous pay intervals with significant discontinuities, both laterally and vertically. Low reservoir energies, consistent with solution-gas-drive oil reservoirs, as well as low effective permeabilities to oil are manifested by primary production recovery efficiencies typically ranging from 8 to 12 percent on 40-acre well spacing.<sup>1-4</sup> Consequently, infill drilling is required not only to increase recoveries from primary production, but also to enhance sweep efficiencies and improve recovery from secondary and tertiary enhanced oil recovery operations. Even at reduced well spacing, however, many operators observe low oil recoveries, poor sweep efficiencies, and early water breakthrough.<sup>1-4</sup> Poor performance at a denser well spacing is indicative of the significant reservoir discontinuity. Accordingly, a better understanding of the reservoir

heterogeneity will help to design and implement enhanced oil recovery operations more successfully.

Moreover, operators in the Permian Basin have historically implemented "blanket" infill drilling strategies in which wells are drilled on uniform patterns and spacing with little consideration of reservoir quality. Development at non-optimum well spacing may result in poor economic returns, even under favorable oil pricing scenarios similar to current conditions. In fact, several previous studies<sup>5-7</sup> have shown that "targeted" infill drilling programs are required to optimize field development by reducing capital expenditures and maximizing economic returns. Targeted infill drilling, however, requires a reservoir characterization program to identify areas of the field with the best quality rock and the largest volume of oil-in-place. Because of the significant volume of original oil-in-place remaining in Permian-age carbonates in West Texas,<sup>8,9</sup> there is an economic incentive for optimizing field development with infill drilling programs, both for primary depletion and enhanced oil recovery operations.

The purpose of this paper is to present the methodology and results of a reservoir characterization study of the Clear Fork carbonates in the TXL South Unit Field located in Ector County, Texas. Similar to a study conducted by Doublet, *et al.*<sup>7</sup> for the North Robertson Unit in Gaines County, we incorporated an integrated approach in which we combined results from geological, petrophysical, and reservoir performance analyses, each representing different reservoir scales. Furthermore, rather than initiating a cost-prohibitive data acquisition program, we conducted our study using existing field data typically available to most operators.

### Historical Field Background

Located in the center of the Central Basin Platform in the Permian Basin, the TXL South Unit encompasses approximately 10,200 acres in the western half of Ector County, Texas. Wells in the TXL South Unit produce from both the Upper Clear Fork (5600 Reservoir) and the Lower Clear Fork (Tubb Reservoir). As shown by Figure 1, current field production is about 1,000 STB/day and 3,000 Mscf/day from approximately 400 active wells.

Similar to most major carbonate oil reservoirs in the Central Basin Platform, the TXL Field was discovered in the mid-1940s. The 5600 Reservoir, initially called the Goldsmith 5600, was discovered in 1946 by the Phillips "E" No. A-1 well located in the northeast part of the field. Several years later,

Ex 45

the Tubb Reservoir was discovered by the Texas Gulf Producing Co. Woodward No. 1 well (currently TXL South Unit Well No. 6001). Prior to being unitized in 1967, the field was developed on 40-acre spacing with most wells drilled in the 1950s. Cumulative production before field unitization was 10.5 MMSTB from 150 wells completed in the 5600 zone and 13.5 MMSTB from 230 well completed in the Tubb reservoir.

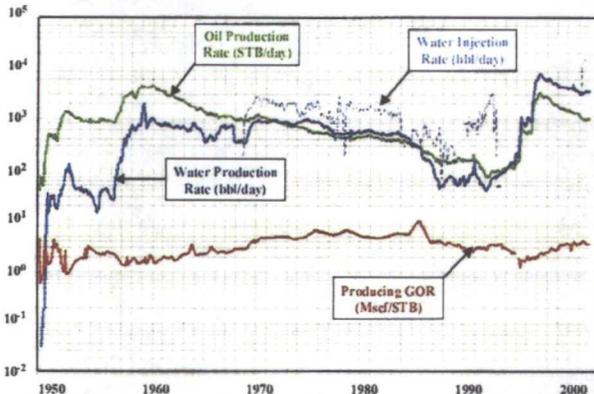


Fig. 1—Historical oil, water, and gas production rates for Clear Fork Carbonates in the TXL South Unit Field, Ector Co., TX.

Following unitization of the field in November 1967, a pilot waterflood project was installed in the northeast part of the unit. The waterflood program was developed with twelve 160-acre inverted nine-spot patterns. In 1976, the operation was converted to several 80-acre line-drive patterns after a number of wells watered out in the east-west direction. The waterflood was again converted to twenty-four 40-acre five-spot patterns following a 24-well infill drilling and well conversion program in 1991 and 1992.

The first significant infill-drilling program was initiated in the mid-1990s after Anadarko Petroleum Corp. acquired the field and became unit operators. Anadarko completed a successful 100-well 20-acre infill drilling program, primarily in the eastern half of the field. Recently, Anadarko initiated a 10-acre infill drilling program in the eastern half of the field and is considering expansion of the secondary recovery operations (approximately 1,000 acres are currently being waterflooded). Cumulative production from the TXL South Unit is 40 MMSTB.

### Summary of Rock and Fluid Properties

Clear Fork carbonates in the TXL South Unit Field are characterized by thick, very heterogeneous pay intervals. Gross interval thickness in the 5600 reservoir ranges from 400 to 500 ft, while the Tubb interval is typically 300 to 400 ft thick. Average effective porosities vary from 6% to 14%, and the *in-situ* connate water saturations range from 30% to 45%. Average effective oil permeability in both zones is typically less than 1 md, but is much lower in some intervals. The Clear Fork carbonates in the TXL South Unit Field are also characterized by significant discontinuities in both lateral and areal directions. Diagenetic processes have maintained and even enhanced porosity in some areas, but the lack of connectivity is manifested by low effective oil permeabilities and small well drainage areas during primary depletion.

The 5600 and Tubb reservoirs are solution-gas-drive oil reservoirs with low recovery efficiencies. Initial reservoir pressures for both reservoirs appear to be equal to or slightly greater than the initial bubblepoint for the reservoir fluid. Initial fluid properties, summarized in Table 1, were obtained from analysis of fluid samples taken in 1946 from the Shell Thomas No. 3 (currently the TXL North Unit 635U well) located adjacent to and immediately north of the TXL South Unit Field.

Table 1—Initial Reservoir Fluid Properties for the Upper and Lower Clear Fork Zones, TXL South Unit

Property	Upper Clear Fork (5600 Reservoir)	Lower Clear Fork (Tubb Reservoir)
$p_i$ (psia)	2,330	2,600
$p_b$ (psia)	2,330	2,600
$B_o$ (RB/STB)	1.37	1.53
$R_{si}$ (scf/STB)	720	1,100
$\mu_o$ (cp)	0.85	0.85
$S_w$ (%)	43	39
$\gamma_o$ ( $^{\circ}$ API)	36 to 38	35 to 37

### Geological Study

Although well performance analysis was the primary evaluation tool, an integral part of our reservoir characterization study was the development of a geological model for Clear Fork carbonates in the TXL South Unit Field. This study represents a much larger reservoir scale than the well performance analyses and was especially critical for developing an understanding of the effects of reservoir heterogeneity and layer continuity on well performance.

### Geology of Clear Fork Carbonates, TXL South Unit Field.

The Clear Fork carbonates at the TXL South Unit consist of approximately 1,100 to 1,200 ft of completely to partially dolomitized carbonate cycles. The interval has typically been divided into the Upper Clear Fork (5600 zone, approximately 475 to 500 ft thickness), the Tubb sand (approximately 125 to 150 ft thickness), and the Lower Clear Fork (Tubb interval, approximately 500 to 550 ft thickness). The Clear Fork is overlain by the Glorieta and underlain by the Wichita formations, both of which frequently contain hydrocarbons. Figure 2 is a type log from the TXL South Unit Field. Tracks 1-3 contain gamma ray, deep induction log, and neutron-density crossplot porosity, respectively.

Core and log information indicate the Clear Fork at the TXL South Unit contains numerous shoaling upward shallow-water carbonate cycles on the order of 1-15 ft in thickness. These facies include subtidal platform facies, grainy shoal and shoal-flank facies, muddy tidal flat facies with eolian silt, and evaporitic tidal flat-supratidal facies. Also seen in core are rooted exposure surfaces and coaly plant debris.

Dolomitization is the most significant diagenetic event at the TXL South Unit Field. Grain dissolution and solution enhancement of moldic and fenestral pores are also observed and can be a significant permeability enhancer compared to similar facies where dissolution is absent. Although limestone

with solution enhanced moldic porosity is an important target at the TXL South Unit Field, it is only present in the lower Clear Fork. More limestone is preserved to the south and east parts of the field. Apparently, dolomitization occurred in fronts moving from northwest to southeast and did not follow structure. Limestone has poor to moderate reservoir quality, but was previously unrecognized and not developed.

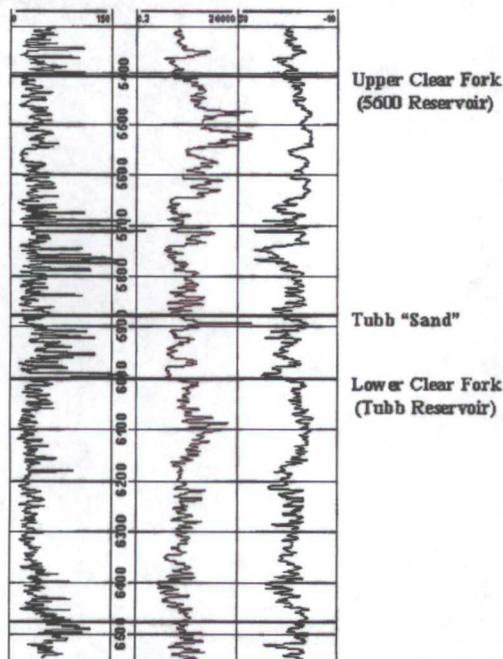


Fig. 2—Type log for Clear Fork carbonates in the TXL South Unit Field, Ector County, TX.

**Distribution of Permeability and Porosity in the TXL South Unit Field.** Similar to observations made in Clear Fork carbonates in other fields, individual facies do not show evidence of well-defined trends of porosity and permeability at TXL South Unit Field. The absence of any readily identifiable trends in properties is likely caused by dolomitization and preferential solution enhancement of porosity in some facies near cycle tops. These diagenetic processes tend to destroy any original permeability-porosity relationships. Consequently, neither pore-throat size nor distribution is an accurate predictor of reservoir quality.

We have also observed that some porosity trends appear to be influenced by structure, especially in the Lower Clear Fork where there is less dolomitization. This observation supports reports that indicate porosity distribution is initially but only partially controlled by depositional topography. Most significant alterations in both the magnitude and distribution of porosity occurred later and were influenced primarily by dolomitization. Complexities in porosity and permeability distribution make it difficult to compute effective porosity using traditional log and facies analysis. As a result, we developed a "rock-log" petrophysical model, which attempts to account for depositional and diagenetic influences, to compute porosity and permeability from the log responses. Development of this model is discussed in the next section.

### Petrophysical Study

The productive intervals within the aggregate Clear Fork section are difficult to define using conventional logging suites because of the complex pore system caused by depositional and diagenetic processes. In the past, we have used a porosity cutoff to define net pay. Unfortunately, the absence of a unique relationship between porosity and permeability precludes accurate and consistent net pay identification using porosity only. For example, vugs and solution cavities will have high porosity, but will exhibit low permeability because of poor connectivity between pores. To illustrate this problem, consider the semilog plot of core-derived permeability against core-derived porosity shown in Figure 3. Note the lack of any discernible relationship between permeability and porosity.

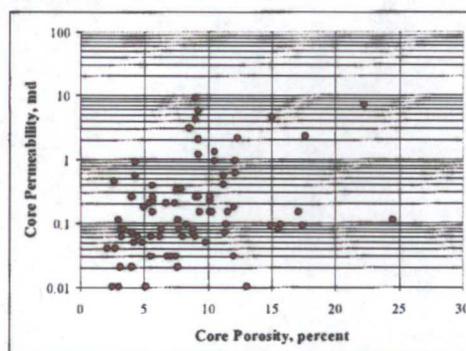


Fig. 3—Plot of core-derived porosity-permeability for all carbonate rock types in the TXL South Unit Field.

To better understand the relationship between observed facies and production performance in the TXL South Unit Field, we developed a petrophysical or "rock-log" model using a methodology similar to previous studies.<sup>7,10,11</sup> The primary objective of the petrophysical study was to develop a robust model (*i.e.*, calculation algorithm) that allowed us not only to identify rock type but also to quantify net pay, effective porosity, and absolute flow capacity from the geophysical well log response. Our rock-log model directly integrated pore-level geometric attributes with basic wireline log measurements.

We used approximately 500 ft of existing or legacy whole core from two wells and 120 ft of additional core taken as part of this study. Plugs were selected from all three whole cores over the entire vertical section using a sampling interval of approximately one-foot. Additional plugs were taken to target specific intervals of interest. Our goal in this sample selection was to obtain a statistically significant and representative sampling of each rock type. Following the plug selection, we measured permeability and porosity on all plugs. We also measured capillary pressures on a subset of plugs.

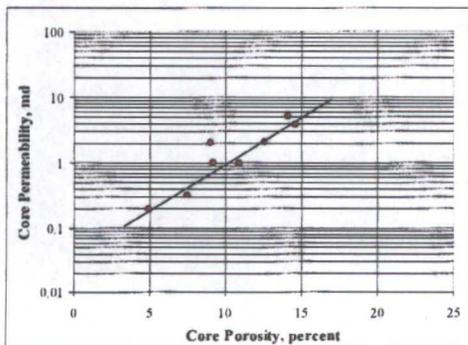
The first interpretive step identified rock types on the basis of lithology only. Plugs were categorized primarily by dolomite, limestone, and siltstone lithologies within the core. The next stage of rock typing characterized plugs on the basis of pore geometry determined using petrographic analysis of thin sections (TS) and scanning electron microscopy (SEM) images.<sup>10-13</sup> Pore geometrical attributes included pore-body size, shape, and arrangement. We also integrated high-

pressure mercury-injection capillary pressures with SEM analysis of pore casts to further quantify the distribution of pore throat sizes. Final rock types were identified from their pore aspect ratios and coordination numbers.

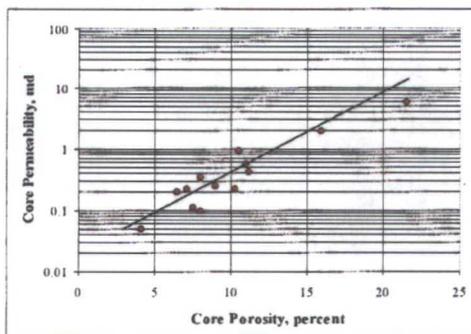
Seven hydraulic rock types, listed in Table 2, were identified based on lithology, pore geometry, and porosity-permeability relationship. For each rock type, we observed a more unique relationship between porosity and permeability at the plug level than seen for the aggregate Clear Fork interval. Permeability-porosity relationships for the best reservoir rocks (*i.e.*, rock types 1, 2 and 6) are shown in Figures 4-6, respectively. Although not shown, similar permeability-porosity relationships were observed for the poorer quality reservoir rocks in the Clear Fork, *i.e.*, rock types 3-5, 7.

**Table 2—Description of Rock Types Defined for Clear Fork Carbonates in the TXL South Unit Field**

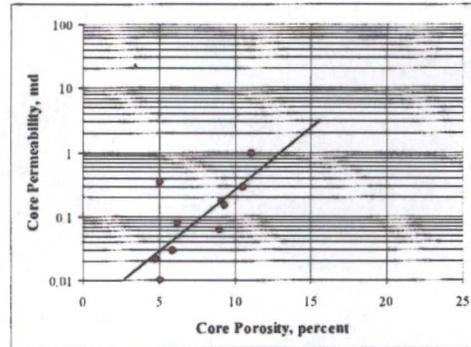
Rock Type	Lithologic Description
Rock Type 1	Medium to coarsely crystalline dolo-grainstones (best reservoir quality)
Rock Type 2	Medium crystalline dolo-grainstone (moderate reservoir quality)
Rock Type 3	Finely crystalline dolo-wackestone (poor reservoir quality)
Rock Type 4	Very fine crystalline dolo-wackestone (poor reservoir quality)
Rock Type 5	Siltstone (poor reservoir quality)
Rock Type 6	Limestone (moderate reservoir quality)
Rock Type 7	Anhydritic dolo-stone (poor reservoir quality)



**Fig. 4—Core-derived porosity-permeability relationship for rock type 1 (medium to coarsely crystalline dolo-grainstones).**



**Fig. 5—Core-derived porosity-permeability relationship for rock type 2 (medium crystalline dolo-grainstones).**



**Fig. 6—Core-derived porosity-permeability relationship for rock type 6 (moderate reservoir quality limestone).**

The next step was to develop an algorithm relating rock types and average rock properties to log responses. The objective of this step was to develop a model to estimate properties at each well. We attempted to use all available log data, including older gamma ray and electric logs taken from wells drilled in the 1940s and 1950s as well as more modern porosity and induction log suites from wells drilled in the 1980s and 1990s. One of the primary considerations in constructing the model was to insure that it could be applied uniformly and consistently throughout the field. Consequently, a significant part of the study effort was focused on normalizing the log data in order to correct observed inconsistencies between log responses. These inconsistencies were observed not only between logs of different vintages, but also log suites obtained from different service companies.

Following the log normalization process, first order or petrophysical rock types were identified using conventional means. For example, silts were identified with gamma ray response, while limestone and dolomite were characterized using the photoelectric response. The hydraulic rock types used a resistivity ratio technique for identification from the log response. The final product was a calculation algorithm that allowed us to identify the vertical distribution of hydraulic rock types as well as to quantify net pay, effective porosity, and absolute permeability from the log response.

### Reservoir Performance Study

The third phase of our field study was the analysis of long-term production histories using the material balance decline type curve (MBDTC) methodology.<sup>7,14</sup> The theory and methodology of the MBDTC analysis technique have been discussed by others<sup>7,14</sup> and will not be repeated in detail in this paper. In general, the type curve method is applicable to variable rate, variable bottomhole flowing pressure, or combinations of these flowing conditions. Application of three different type curve plotting functions—normalized rate, rate integral, and rate derivative—allows us to obtain more unique type curve matches, even from typical field data with significant scatter. The type curves used in our study were developed specifically for pressure depletion production from solution-gas-drive reservoirs such as the TXL South Unit Field.

A major objective of the reservoir performance study was to quantify reservoir properties for both the 5600 and Tubb reservoirs. Consequently, we limited this phase of our study to the analysis of production that was not commingled. From the analysis of transient data, we estimated the effective permeability to oil and the near-wellbore flowing efficiency presented in terms of a skin factor. Furthermore, analysis of the pseudosteady-state or boundary-dominated data provided estimates of contacted oil-in-place and drainage area. We illustrate the performance analysis with several examples.

**Example Analysis: Well TXLSU 1004 (5600 Reservoir).** Figure 7 shows the production and development history of Well TXLSU 1004 that was completed openhole in the Upper Clear Fork in August of 1950. Following a small acid treatment, the well initially produced at a rate of almost 40 STB/day. Artificial lift was installed in December of 1950. In an attempt to increase production, the well was hydraulically fractured in December 1954 with 20,000 lbs. of 20/40 sand. Note the well responded with a post-fracture rate of more than 60 STB/day.

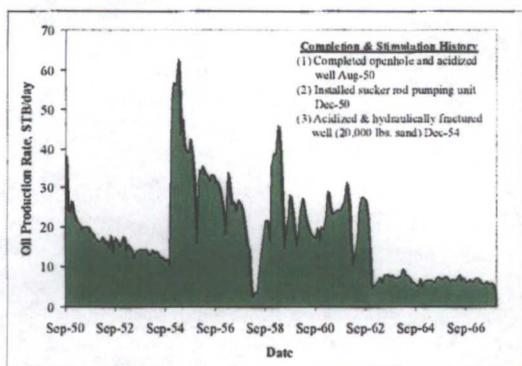


Fig. 7—Well development and completion history, Well TXLSU 1004 (5600 Reservoir).

Since there was no bottomhole pressure data available, we estimated the primary moveable oil volume or ultimate oil recovery (EUR) from a plot of daily oil rate against cumulative oil production (Fig. 8). Theoretical aspects for this technique are discussed in References 7 and 15.

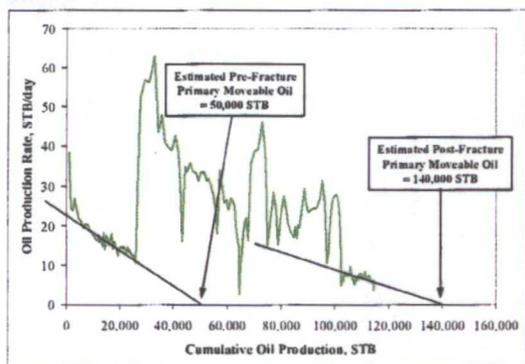


Fig. 8—Estimated ultimate primary moveable oil recovery for Well TXLSU 1004 (5600 Reservoir).

The primary moveable oil volume represents the total oil volume the well could produce under a given set of operating conditions. In some cases, the EUR can be increased by improving operating conditions. We estimate the primary moveable oil volume from the best-fit line drawn through the late-time rate data and extrapolated to the cumulative oil production axis. Note the post-fracture EUR exceeds the pre-fracture volume by 90,000 STB. This difference suggests the hydraulic fracture treatment possibly improved the well's flowing efficiency and/or contacted more reservoir pore volume.

Figures 9 and 10 show the material balance decline type curve (MBDTC) analysis of the pre- and post-fracture production history, respectively. Consistent with the EUR evaluation, we also observed an improvement in the well performance following the hydraulic fracture treatment. The computed skin factor decreased from a  $-1.5$  to  $-3.1$ , while the drainage area increased from 30.6 to 56.5 acres. In addition, the computed effective oil permeability increased from 0.11 md to 0.19 md, suggesting the fracture treatment not only contacted more reservoir pore volume but also contacted more permeable portions of the reservoir. Note also that, even following the hydraulic fracture treatment, this well recovered less than 8 percent of the contacted oil-in-place.

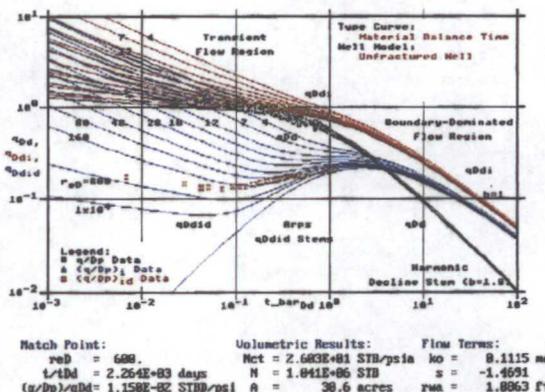


Fig. 9—MBDTC analysis of pre-fracture production history, Well TXLSU 1004 (5600 Reservoir).

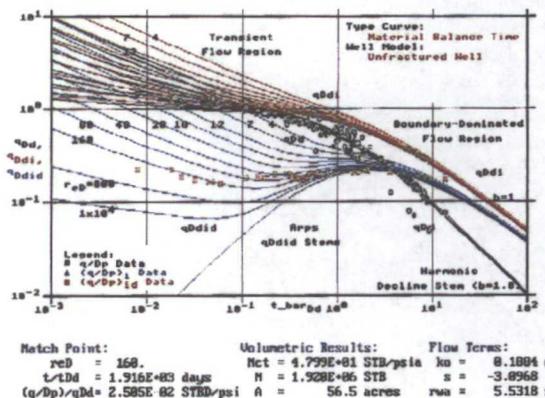


Fig. 10—MBDTC analysis of post-fracture production history, Well TXLSU 1004 (5600 Reservoir).

**Example Analysis: Well TXLSU 2401 (Tubb Reservoir).** This example illustrates a hydraulic fracture treatment that did not increase the well's EUR but did accelerate production. Well TXLSU 2401 was a dual completion in both upper and lower Clear Fork zones, but the production prior to field unitization was not commingled. The Tubb zone, which was completed and acidized in July 1951, initially tested at a rate of about 28 STB/day but declined to less than 20 STB/day within a year (Fig. 11). Following a 40,000-lb sand hydraulic fracture treatment in November 1956, the well responded with a test rate approaching 50 STB/day.

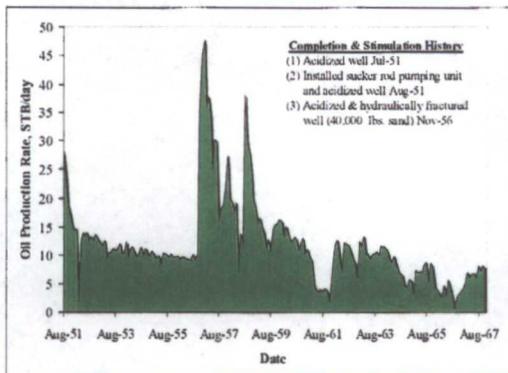


Fig. 11—Well development and completion history, Well TXLSU 2401 (Tubb Reservoir).

The pre- and post-fracture primary moveable oil volumes were also estimated from a plot of oil rate against cumulative oil volume. As seen in Figure 12, the hydraulic fracture treatment did not appear to significantly increase the EUR. We did, however, accelerate production of the primary moveable oil volume.

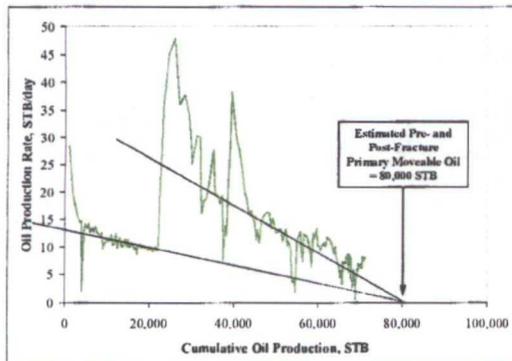


Fig. 12—Estimated ultimate primary moveable oil volume for Well TXLSU 2401 (Tubb Reservoir).

The MBDTTC analysis of the pre- and post-fracture production histories, illustrated in Figures 13 and 14, are also consistent with the EUR evaluation. The pre- and post-fracture drainage areas of 26.0 and 28.5 acres are almost equal. In addition, the computed effective oil permeability increased from 0.069 md to 0.11 md, suggesting the fracture treatment contacted more permeable zones in the reservoir. We also observe that the sand fracture treatment did decrease the skin factor from -1.8 to -4.0. Finally, note that the primary

oil recovery efficiency for this well was slightly more than 9 percent, which is similar to other Clear Fork producers in the Permian Basin.

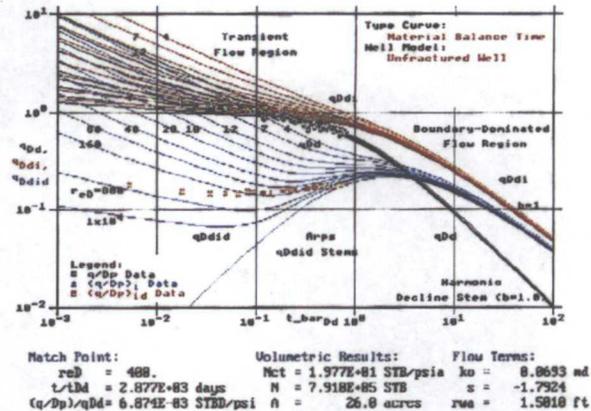


Fig. 13—MBDTTC analysis of pre-fracture production history, Well TXLSU 2401 (Tubb Reservoir).

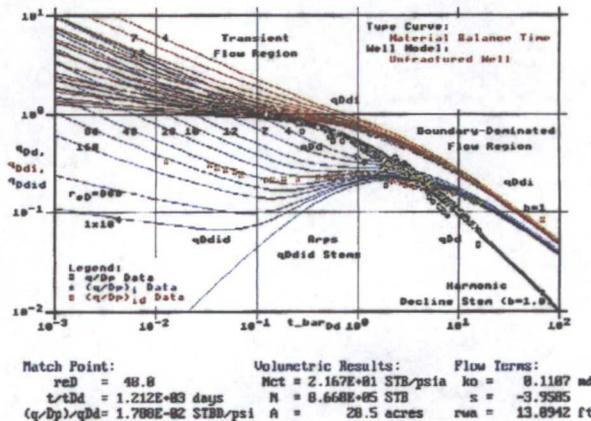


Fig. 14—MBDTTC analysis of post-fracture production history, Well TXLSU 2401 (Tubb Reservoir).

**Example Analysis: TXLSU Well 4203 (Tubb Reservoir).** The final example illustrates one of the more productive wells in the TXL South Unit Field. Most wells completed in either the upper or lower Clear Fork zones required hydraulic fracturing with sand proppant during primary production. We were unable to find any record of hydraulic fracture treatment during the pre-unitization period for the Well TXLSU 4203. As shown by the production history in Figure 15, the Tubb zone was completed openhole and acidized in January 1951. Initially testing almost 70 STB/day, the well declined more slowly than the typical TXL South Unit well. We also observed a slight increase in production after a second acid treatment and installation of artificial lift in April 1956. We computed a primary moveable oil volume of 100,000 STB (Fig. 16).

Figure 17 shows the material balance decline type curve analysis of the well production history. This analysis suggests the well was contacting almost 1,800,000 STB oil, which is equivalent to a drainage area of more than 58 acres. Note that this contacted drainage area is greater than the average observed in most wells in the TXL South Unit Field. The

primary oil recovery efficiency was, however, still less than 10 percent of the contacted oil-in-place.

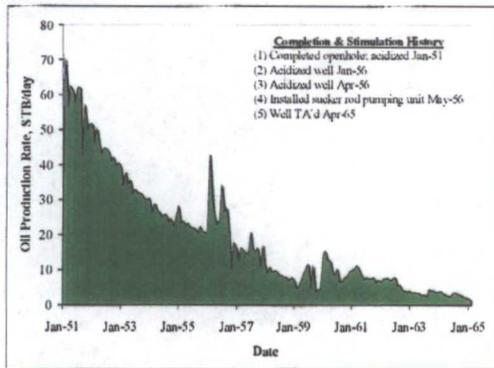


Fig. 15—Well development and completion history, Well TXLSU 4203 (Tubb Reservoir).

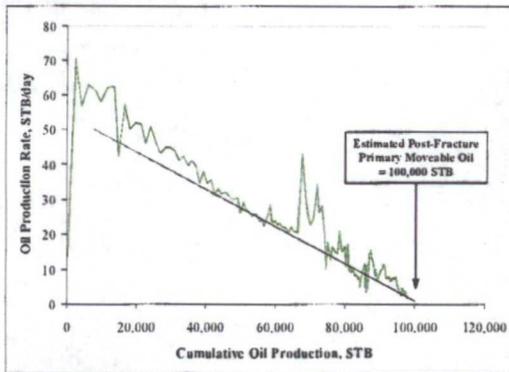


Fig. 16—Estimated ultimate primary moveable oil volume for Well TXLSU 4203 (Tubb Reservoir).

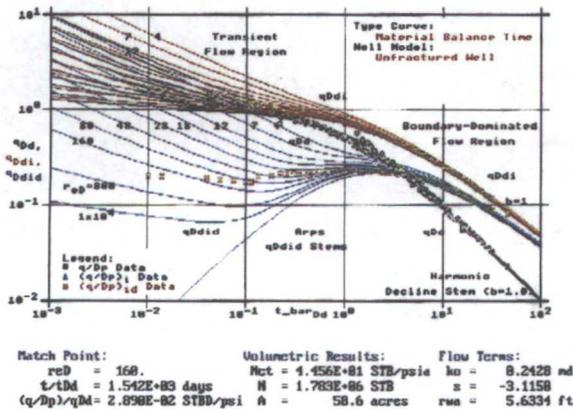


Fig. 17—MBDTC analysis of oil production history, Well TXLSU 4203 (Tubb Reservoir).

**Integration of the Petrophysical Model and Reservoir Performance Analysis**

We were also able to validate our reservoir performance analysis as well as confirm the petrophysical study. Recall from our petrophysical study that we identified seven rock types (Table 2), from which rock types 1, 2, and 6 appear to be the most continuous and represent the best reservoir quality, while rock types 3-5 and 7 are either poorer-quality or non-

reservoir zones. Furthermore, we believe rock types 1, 2, and 6 are not only the principle sources of primary oil production at 40-acre spacing, but are also the principle targets for infill drilling and waterflooding at most reduced well spacings.

To confirm these hypotheses, we compared a log-based volumetric oil-in-place volume against a production-based contacted oil volume. The log-based or volumetric oil-in-place was computed using analysis of modern well logs from 20-acre wells drilled in the 1995 development program. The production-based oil-in-place was the average of the contacted oil volumes from the MBDTC analysis of the four 40-acre wells surrounding the 20-acre wells. The rock-log model was used to identify the vertical distribution of hydraulic rock types and to quantify net pay, effective porosity, and absolute permeability.

Initially, we included all rock types to compute the log-based oil-in-place. We then systematically eliminated a rock type until the best match between the log-based and production-based volumes was observed. The best match was obtained using net pay zones composed of the best reservoir rock, i.e., rock types 1, 2 and 6. As shown in Figure 18, most of the data (green circles) form a 45-degree line, thus seeming to validate our analysis. The cluster of data above the 45-degree line (red circles) represents 20-acre wells completed in the deep Tubb limestone identified from the geological and petrophysical study. None of the older 40-acre wells was completed in this deep Tubb zone and is, therefore, not contacting this oil volume.

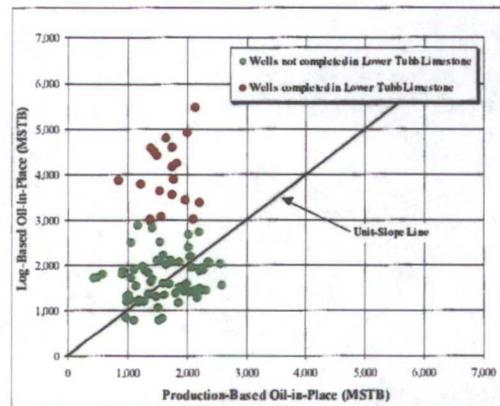


Fig. 18—Comparison of volumetric log-based and production-based or contacted oil-in-place volumes for rock types 1, 2 and 6.

**Reservoir Characterization Study Results**

One significant conclusion reached from several previous studies<sup>6,7</sup> of Permian-age carbonates is that the best locations for 10-acre and 20-acre infill wells are usually in the same areas as the best 40-acre producers. This conclusion suggests that identification of areas of the best reservoir quality and largest remaining oil-in-place volumes may be more important than finding the areas of poor reservoir continuity. This observation also suggests a direct correlation between primary moveable oil volume and reservoir flow capacity.

To verify if this observation is valid in the TXL South Unit Field, we plotted EUR against effective oil flow capacity determined from the MBDTC analysis. As shown in Figures

19 and 20, EUR is an excellent indicator of reservoir quality in both the Upper and Lower Clear Fork. Note that these results incorporated production decline type curve analysis of 40-acre wells only.

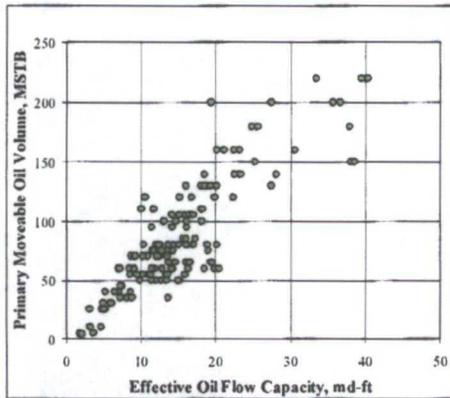


Fig. 19—Relationship between primary moveable oil volume and effective oil flow capacity for 150 wells producing from the 5600 Reservoir.

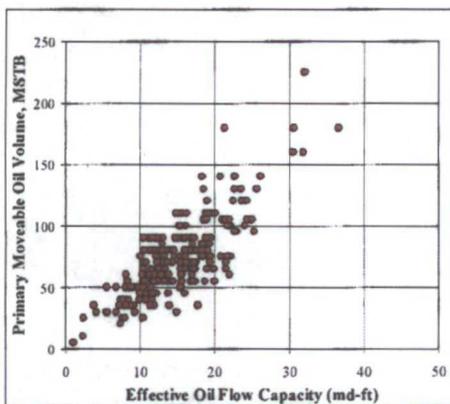


Fig. 20—Relationship between primary moveable oil volume vs. effective oil flow capacity for 230 wells producing from the Tubb Reservoir.

To further validate our hypothesis, we also mapped MBDTC analysis results for all 40-acre producers in both the upper and lower Clear Fork zones. Figure 21 is contour map of the effective oil flow capacity computed from the MBDTC analysis of wells producing from the 5600 and Tubb Reservoirs. The map was generated using a contour interval of 10 md-ft with decreasing oil flow capacity corresponding to increasingly darker colors. Similarly, Figure 22 is map of the contacted oil-in-place volumes for the 5600 and Tubb Reservoirs. This map was created using a contour interval of 400,000 STB with decreasing oil-in-place volumes corresponding to increasingly darker colors. Finally, a map of primary moveable oil volumes (EUR), shown in Figure 23, was generated using a contour interval of 25,000 STB. Again, decreasing values of EUR correspond to increasingly darker colors.

Note that areas of the largest effective oil flow capacity are generally in the eastern half of the field and centered around the crest of the anticline structure. We also observe that the largest contacted oil-in-place and primary moveable oil

volumes (*i.e.*, EURs) generally correspond to areas of the highest oil flow capacity. The converse is also true. These maps also seem to confirm observations from previous studies which suggest that identification of areas of the best reservoir quality may be more important than finding the areas of poor reservoir continuity.

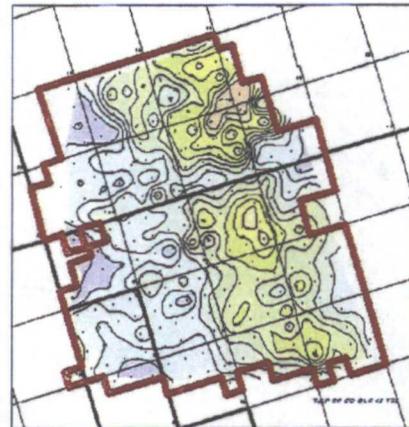


Fig. 21—Distribution of effective oil flow capacity in the 5600 and Tubb Reservoirs, TXL South Unit Field.

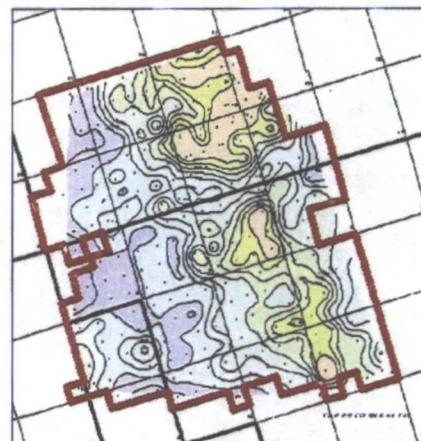


Fig. 22—Distribution of contacted oil-in-place volumes in the 5600 and Tubb Reservoirs, TXL South Unit Field.

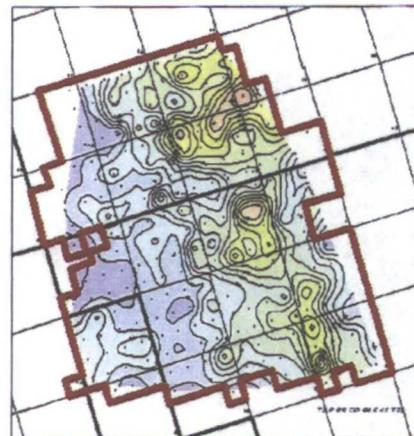


Fig. 23—Distribution of primary moveable oil volumes in the 5600 and Tubb Reservoirs, TXL South Unit Field.

### Continuity Model for the TXL South Unit Field

Using the results of our field study, we have postulated a reservoir continuity model that will form the basis for future simulation studies of the TXL South Unit Field. The TXL South Unit Field can be described as a multi-layer reservoir with significant heterogeneity, both areally and vertically. Contrary to conventional wisdom, however, the TXL South Unit Field also has some hydraulically continuous pay zones extending over several well spacings. These continuous pay zones are composed primarily of rock types 1, 2 and 6. There are also multiple discontinuous and less productive zones with limited areal extent. These zones are mostly composed of rock types 3-5 and 7. Well productivity appears to depend more on the total flow capacity of the contacted zones and much less on variations in permeability.

The principle sources of primary oil production in the TXL South Unit Field are rock types 1 and 2 (good to moderate quality dolomites) and rock type 6 (moderate quality limestone). Characterized by good to moderate flow capacities and injectivities, pay zones with these rock types are targets for both primary production and waterflooding at well spacings of 40 acres. These pay zones are also more continuous across greater distances than previously envisioned. We also observed that rock types 1, 2, and 6 have a range of properties, and many pay zones are composed of these rock types with flow capacities at the lower end of the range. Because of the significant oil-in-place remaining, these zones will continue to contribute to primary production at 20- and 10-acre well spacings. Moreover, we believe these zones will be economic to waterflood or perhaps be targets for tertiary enhance oil recovery operations.

We designate other zones as sub-economic or even non-reservoir rock types. These zones, characterized by very poor flow capacities, probably contribute little primary oil production on 40-acre well spacing with vertical wells but may be targets for development on more dense well spacings. Poor injectivities also preclude effectively waterflooding zones containing these rock types. Because of significant remaining oil-in-place volumes, these zones may be targets for development using advanced technologies such as multi-laterals and horizontal wells. However, further study and characterization is required.

### Conclusions

On the basis of our study of the TXL South Unit Field, we offer the following conclusions:

1. Similar to the study conducted by Doublet, *et al.*,<sup>7</sup> we have shown a production-based methodology using well performance analysis can be used to characterize the reservoir and to identify areas of the field for infill drilling. This technique is especially valuable since it uses production data that is typically available to all operators.
2. The results of our work agree with several previous studies suggesting the best locations for 5-acre, 10-acre and 20-acre infill wells are usually in the same areas as the best 40-acre producers. This observation, which was illustrated with the excellent correlation among effective

oil flow capacity, primary moveable oil volume, and contacted oil volume, also indicates identification of areas of best reservoir quality may be more important than finding areas of poor reservoir continuity. Identification of areas of the field with the best reservoir quality and highest remaining volume of oil-in-place allows an operator to target their infill drilling rather than initiating a blanket drilling program.

3. Productive intervals, identified as zones containing rock types 1, 2 and 6, are generally more hydraulically continuous and extend further than initially believed. These zones, characterized by good to moderate flow capacities and injectivities, are the principal sources of primary production on 20-acre and 40-acre spacings. These zones are also the chief targets for primary production and waterflooding on reduced well spacings.
4. The less productive intervals, identified as zones containing rock types 3-5 and 7, generally have much lower flow capacities than rock types 1, 2, and 6. Consequently, these zones probably contribute little primary production on 40-acre well spacing with vertical wells, but may be developed economically at reduced well spacings. Poor injectivities also preclude waterflooding at any well spacing. Because of the significant oil-in-place volume remaining, these intervals may be targets for development using advanced technologies.
5. We were able to complete our reservoir characterization and infill drilling study using existing data typically available to operators. Consequently, the cost to complete the study was approximately equal to the cost to drill and complete a single well in the TXL South Unit.

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### Nomenclature

- $A$  = well drainage area based on contacted oil-in-place volume from MBDTC analysis, acres  
 $B_{oi}$  = oil formation volume factor at initial reservoir conditions, RB/STB  
 $EUR$  = estimated ultimate oil recovery or primary moveable oil volume, STB  
 $k_o$  = effective permeability to oil, md  
 $N$  = contacted oil-in-place from MBDTC analysis, STB  
 $p_b$  = reservoir bubblepoint pressure, psia

- $p_i$  = initial reservoir pressure, psia  
 $R_{si}$  = solution gas-oil ratio at initial reservoir conditions, scf/STB  
 $s$  = skin factor, dimensionless  
 $S_w$  = water saturation, fraction  
 $\mu_o$  = oil viscosity, cp  
 $\gamma_o$  = oil gravity, degrees API

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