SPE 24884

Society of Petroleum Engineers

Reservoir Evaluation, Completion Techniques, and Recent Results From Barnett Shale Development in the Fort Worth Basin

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This paper was prepared for presentation at the 67th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Washington, DC, October 4–7, 1992.

ABSTRACT

This paper describes the evaluation, completion, stimulation, and testing of Barnett Shale wells operated by Mitchell Energy Corporation (MEC) in the Fort Worth Basin of north-central Texas. In particular, the paper presents a detailed analysis of data collected from a Gas Research Institute/MEC cooperative research well that was used to gain a better understanding of the mechanisms controlling gas production from the Barnett Shale. The Barnett Shale covers a large geographic area of north-central Texas; thus far, most of the activity is centered around Wise and Denton Counties, TX.

On the basis of the data analyzed, the Barnett Shale appears to be characterized best with a layered reservoir description where most of the well deliverability is associated with thin, higher permeability, naturally fractured zones, while most of the gas-in-place is confined to thicker, extremely low permeability layers. Gas-in-place in the Barnett Shale may average 10 to 12 Bscf per 160 acres, but the better wells are expected to recover only 1 to 1.5 Bscf in a twenty-year well life. Approximately 20% of the gas-in-place in the Barnett Shale is adsorbed gas; however, desorption appears to become important only after the reservoir pressure falls below 1,000 psia (original reservoir pressure is about 4,000 psia). Evaluation of fracturing pressures and post-fracture well tests suggests long, propped hydraulic fractures are being achieved and that the hydraulic fractures are typically contained within the Barnett Shale by limestone formations above and below.

INTRODUCTION AND GEOLOGIC SETTING

The Barnett Shale occurs in the Fort Worth Basin of north-central Texas; it covers a large geographic area and is one of the most uniform stratigraphic units in the Basin.[1] Fig. 1 illustrates the approximate limits of the Barnett Shale. The Barnett outcrops in central Texas along the Llano uplift, where it is approximately 30 to 50 ft thick. The shale thickens as it dips northward, reaching a maximum thickness of about 1,000 ft at a depth of approximately 8,500 ft near the Texas/Oklahoma state line.[2] To date, essentially all commercial gas production from the Barnett occurs in Wise and Denton Counties, TX. Wells drilled in the western part of the Basin produce small quantities of oil and water, with little or no gas.

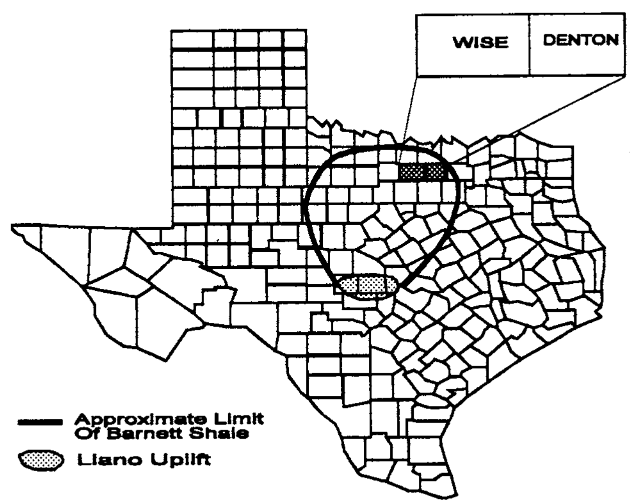


Fig. 1 - Barnett Shale production occurs mostly in Wise and Denton Counties, TX.

References at end of paper.

The Barnett Shale is a Mississippian-age, marine shelf deposit originating on the southwestern flank of a basin formed by the subsiding Southern Oklahoma aulacogen. The sediments were derived from a low-lying craton to the south and west which was composed predominantly of non-siliciclastic rocks. The Barnett unconformably overlies rocks of Early to Middle Ordovician age; it is overlain conformably by shales and limestones of Pennsylvanian age.[3] Outcrop samples of the Barnett Shale vary from a hard black, fossiliferous limestone to a dense, black, soft, thin-bedded, fossiliferous shale;[1] however, drill cuttings from wells near the northern extent of the Barnett are devoid of fossil materials.[3]

Fig. 2 presents typical gamma ray and density logs across the Barnett Shale. The Barnett occurs between 6,500 and 8,000 ft in the Wise-Denton County area and is about 500 ft thick. It is divided into upper and lower intervals by the Forestburg Limestone. The Forestburg ranges from 10 to 20 ft thick to more than 100 ft thick across the Wise-Denton area. The Lower Barnett is the primary productive interval and completion target; few wells are perforated in the Upper Barnett. The Barnett Shale is bounded below by the Viola/Simpson Limestone and above by the Marble Falls Limestone.

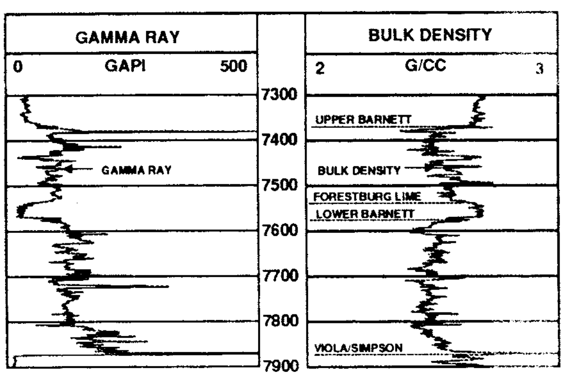


Fig. 2 - Typical gamma ray and density logs for the Barnett Shale.

COMPLETION PRACTICES

Mitchell Energy Corporation (MEC) has drilled and completed most of the wells in the Barnett Shale since the first recorded completion in 1981. Fig. 3 highlights MEC's activity in the Barnett Shale over the past ten years; through 1991, MEC had completed and stimulated almost 100 wells in the Barnett. MEC's typical completion procedure for wells in the Barnett is the following.

1. Drill a 7 7/8-in hole to total depth and run and cement 4 1/2-in casing.

2. Perforate the entire 200- to 300-ft Lower Barnett interval with 65 to 70 holes and acidize with 5,000 gal of 10% NeFe (non-emulsified acid with an iron sequestering agent).

3. Fracture the Lower Barnett with about 500,000 gal of a 50- to 30-lb crosslinked gel, 200 scf/bbl of nitrogen (gas assist), and between 1.2 and 1.5 million pounds of 20/40 sand at 40 bbl/min down casing.

These massive hydraulic fracture (MHF) treatments were first attempted in the Barnett in 1985. As Fig. 3 shows, these large jobs now make up the vast majority of treatments pumped. Typical Barnett wells stimulated with these MHF treatments usually produce between 200 and 250 MMscf in the first year and are expected to recover between 1 and 1.5 Bscf.

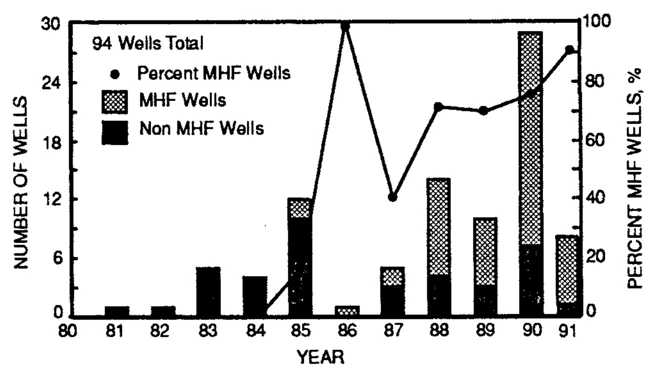


Fig. 3 - MEC's Barnett Shale activity since 1981.

GRI/MEC COOPERATIVE WELL

In late 1990, the Gas Research Institute (GRI) and MEC began work on a cooperative research well, the T. P. Sims 2, in the Barnett Shale. The primary objectives of the Sims 2 well were (1) to learn more about the mechanisms controlling gas production from the Barnett Shale, (2) to determine if technologies developed in GRI's Appalachian Shales and Tight Gas Sands research could be applied to the Barnett, and (3) to gather data for use in planning a nearby horizontal well. Some of the key cooperative well operations and analyses performed on the Sims 2 well included

- openhole log analysis using the Shale-specific log interpretation model[4,5,6] developed for the Appalachian Devonian Shales,
- the cutting and analysis of 145 ft of oriented whole core,
- the running and interpretation of the formation microscanner (FMS),
- two openhole stress tests,
- the monitoring and analysis of pressure data from a mini-frac and the main fracture treatment, and
- a microseismic height and azimuth survey following the mini-frac.

Fig. 4 depicts the cooperative operations performed on the T. P. Sims 2 graphically. As is typical, the primary completion interval was the Lower Barnett, which is about 300 ft thick at this location. The whole core was taken between 7,610 and 7,755 ft. The two openhole stress tests were performed at 7,670 and 7,723 ft, within the cored interval. The FMS was run and interpreted from 7,540 to 7,992 ft, and the shale-specific log interpretation was performed across the entire Barnett Shale interval. The total depth of the Sims 2 well was 7,999 ft.

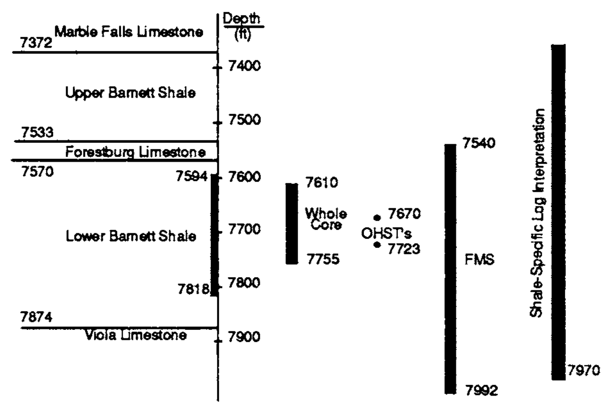


Fig. 4 - Cooperative well operations performed on T.P. Sims 2.

Core Analysis

Fig. 5 shows the mineralogy of the Lower Barnett Shale as determined from x-ray diffraction analysis and total organic carbon (TOC) measurements performed on samples taken from the whole core. The Lower Barnett is composed of approximately 1/3 quartz, 1/3 clays, and 1/3 other minerals including about 7% pyrite, 12% kerogen, 10% carbonates, and 4% apatite. Apatite is a phosphatic mineral that is not inherently radioactive, but has a high affinity for some radioactive element (probably thorium). While there is an average concentration of about 3 to 4% apatite in the Lower Barnett, it tends to occur in thin streaks of much higher concentration and is characterized by a distinctive, high gamma ray response.[7] In comparing the Barnett to the Appalachian Devonian Shales, we have found that the Appalachian shales have a higher volume of quartz and clays, similar kerogen contents, but no carbonates nor apatite.

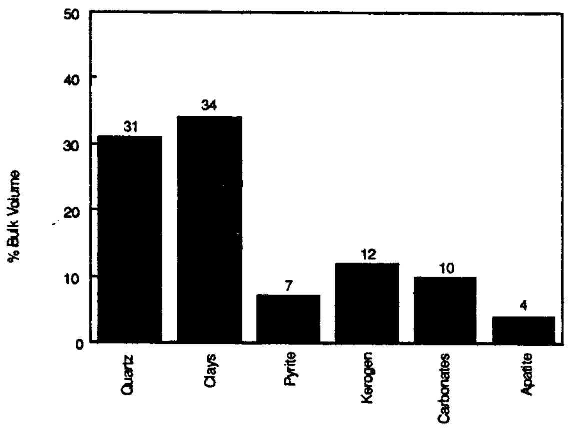


Fig. 5 - Typical Barnett shale mineralogy as determined from x-ray diffraction analysis and TOC measurements.

Fig. 6 presents a comparison between the routine and "crushed" porosities measured on nine samples from the Lower Barnett. The routine porosity measurements were made using toluene-extracted plugs from the whole core. The "crushed" porosities were measured by first crushing the samples into millimeter-sized grains, extracting with toluene, and then measuring the porosity using helium porosimetry. This technique was developed for measuring matrix porosities accurately in the ultra low permeability Appalachian Devonian Shales;[8] it also appears to have worked well in the Barnett.

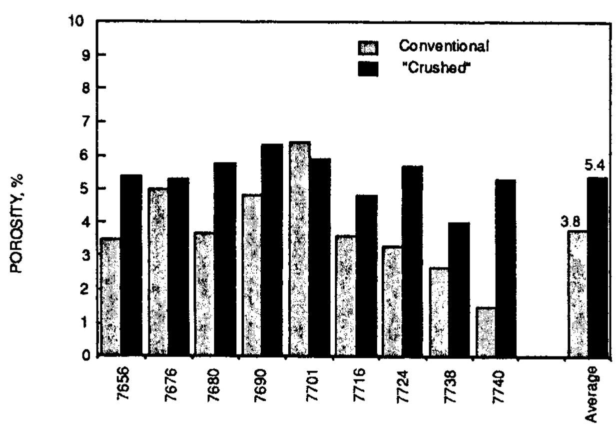


Fig. 6 - Comparison of routine and "crushed" porosity measurements on nine Barnett Shale core samples.

As seen in Fig. 6, the routine porosities measured ranged from 1.5 to 6.4%, while the "crushed" porosities ranged from 4.8 to 6.3%. The "crushed" porosities were uniformly higher than the routine measurements. The average routine porosity in the Lower Barnett was 3.8%; the average "crushed" porosity was 5.4%. This difference between the two measurement methods was less than we observed for the Appalachian Shales,[8] which may suggest the Barnett has somewhat better matrix permeability overall. We did find that the "crushed" porosities compared best to those values determined from the Shale-specific log interpretation in the Barnett; the same is true for the Devonian Shales.[8]

Splits from ten samples were used for TOC and isotherm measurements.[7] Fig. 7 shows the TOC content of each of the ten samples. The TOC values are reasonably high, ranging from 3.3 to 6.8%, and averaging 4.5%. This translates to about 10 to 15% kerogen content in the Lower Barnett, with an average value of about 12% as shown in Fig. 5. Despite the high TOC content, however, the remaining source rock potential of the Barnett Shale is low; the organic matter is very mature and well into the gas zone. The gas zone is the thermal maturity range where gas is the dominant product of hydrocarbon generation from kerogen, and where oil is cracked progressively to gas.

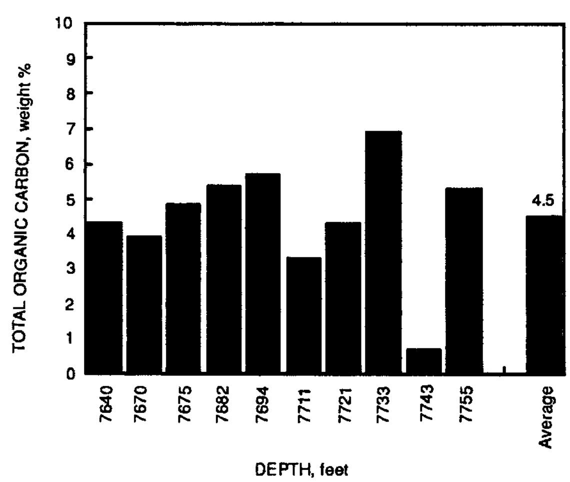


Fig. 7 - Results of TOC measurements on ten Barnett Shale core samples.

Fig. 8 shows a typical methane adsorption isotherm for the Lower Barnett Shale; this one was measured on a sample at 7,640 ft.[7] Fig. 8 is a plot of gas content versus pressure, and actually, three curves are shown. The lower curve represents the amount of helium that can be stored in the porosity as a function of pressure; this reflects the matrix porosity. The middle curve is the actual methane adsorption isotherm, and the top curve shows the total methane storage, porosity + adsorbed gas, in the Lower Barnett.

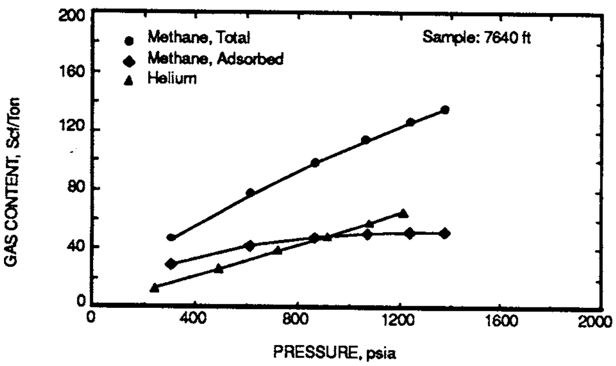


Fig. 8 - Typical methane adsorption isotherm for the Barnett Shale.

The methane adsorption isotherm was measured at 175°F and pressures up to 1400 psia, the limit of the testing equipment used. As Fig. 8 shows, desorption becomes important at pressures below about 1,000 psia in the Barnett; below 1,000 psia, adsorbed gas may account for 50 to 60% of the total gas stored. Above 1,000 psia, however, it appears that the adsorption sites become saturated, and little or no additional adsorption takes place. Gas storage at pressures above 1,000 psia apparently occurs only as free gas in the pore spaces. Typical reservoir pressure in the Lower Barnett is 3,500 to 4,000 psia. Thus, methane adsorption probably accounts for only about 20% of the <u>total</u> gas in place in the Lower Barnett Shale.[7]

We also performed a detailed description of the fractures observed in the whole core taken from the T. P Sims 2 well.[9] Fig. 9 shows the orientation of the fractures we identified. In this core, natural fractures were distinguished from induced fractures by calcite mineralization filling the fractures. Widths for the natural fractures varied from 0.1 mm to 1 mm. The natural fractures strike 100° to 120° or northwest-southeast; they dip 74° to the southwest. The natural fractures tend to terminate within the core, suggesting these fractures may have limited vertical extent. On the other hand, the drilling-induced fractures, and those fractures created during the stress tests, which were subsequently overcored, strike generally from 45° to 80° (northeast-southwest) and dip 80° northwest.

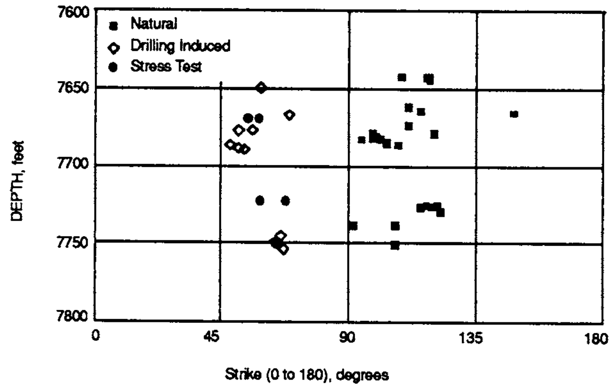


Fig. 9 - Orientation of fractures identified in core from T.P. Sims 2 well.

<u>Log Analysis</u>

Openhole logs run in the T. P. Sims 2 well included the dual induction, gamma ray, lithodensity, compensated neutron, microlog, digital array sonic, and formation microscanner (FMS). In addition to these measurements, logging suites from seven other wells and whole core from one other well composed the database from which the Barnett log analysis model was constructed.

Using these data, we applied the Shale-specific log interpretation model developed previously for the Appalachian Devonian Shales[4,5,6] to the Barnett Shale. Some modifications were required to the Appalachian model to account for the thin beds of apatite that occur in the Lower Barnett,[7] but not in the Appalachian Shales. As mentioned previously, we observed that apatite has a high affinity for some radioactive element, probably thorium, and the gamma ray response must be corrected for apatite in order to determine kerogen volume correctly. With these minor modifications, however, the Shale-specific model appeared to work well for estimating mineralogy, porosity, and fluid saturations in the Lower Barnett.[7]

Fig. 10 presents the Shale-specific log interpretation for the T. P. Sims 2.[7] In Track 1, the gamma ray and caliper logs are shown. In Track 2, the total bulk volume mineralogy is presented, with fractions of the bulk volume occupied by quartz, clays, dolomite, calcite, kerogen, pyrite, and porosity identified. In this interval, there is only one significant apatite stringer located right at the base of the Lower Barnett (not labeled).

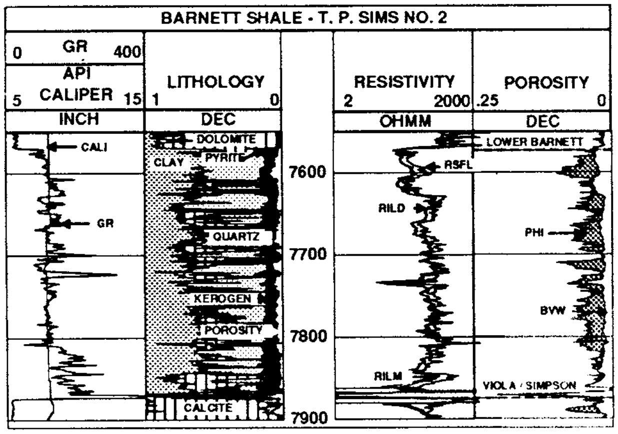


Fig. 10 - Shale-specific log interpretation for the Barnett Shale in the T.P. Sims 2 well.

Track 3 presents the medium and deep induction logs, while Track 4 shows the bulk volume porosity analysis. In this track, that portion of the porosity occupied by free gas is stippled, while the water-filled pore volume is white. Using this interpretation, we estimated the Lower Barnett Shale in the Sims 2 well to have 166 ft of gas-filled (net) pay with an average porosity of 5.9% and an average water saturation of 32.3%. At a reservoir temperature of 200 °F and a reservoir pressure of 4000 psia, this equates to about 10.5 Bscf of gas in place per 160 acres.[7] This value includes free gas in the porosity only; as reported earlier, adsorbed gas probably adds an additional 20% to the total gas in place.

Interpretation of the FMS also revealed a number of fractures, both natural and induced.[9] Fig. 11 presents the orientation of the fractures identified from the FMS. In the FMS interpretation, natural fractures were distinguished from induced fractures by their higher resistivity, lower dip angle, and difference in strike. As Fig. 11 shows, the FMS results agreed well with those from the core. Again, the natural fractures were observed to strike 100° to 120° and to dip southwest, while the induced fractures have a mean strike of 55°, dipping 81° northwest.[9]

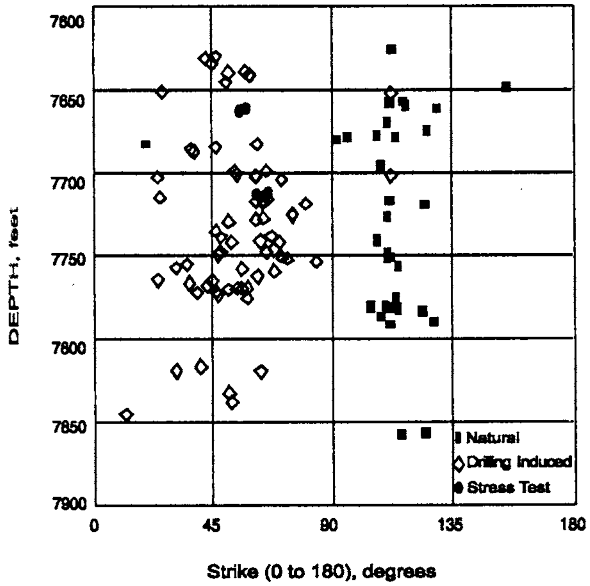


Fig. 11 - Orientation of fractures identified from FMS interpretation in the T.P. Sims 2 well.

Clearly, a significant difference exists between the orientation of the natural and induced fractures in the Lower Barnett; in this instance, the average angle of intersection is 67°.[9] These results suggest that the stress field has changed in the Barnett Shale from the time the natural fractures were developed. It also suggests that a hydraulic fracture treatment should tend to intersect, rather than parallel, the natural fractures in the Barnett.

Although it is not obvious from Figs. 9 and 11, we also observed that the natural fractures in the Lower Barnett Shale tend to occur in clusters (or layers) as a function of depth. (There tends to be a more distinct concentration of the fractures in discrete intervals than these figures suggest.). Further, we have been able to correlate these apparent natural fracture clusters with a crossover in the sonic and neutron logs. This crossover effect has proven to be quite useful in selecting completion intervals and identifying which wells are likely to be better producers. These results and those from the core analysis suggest that the natural fractures in the Barnett Shale tend to be limited in vertical extent, may tend to occur in relatively thin layers, and are responsible for increased productivity when encountered.

Mini-Frac and Main Fracture Treatments

A mini-frac was performed on the Sims 2 well, consisting of 30,000 gal of crosslinked gel pumped down 5 1/2-in casing at 40 bbl/min. Only surface pressures and rates were recorded during the treatment. Following the mini-frac, a microseismic logging survey and tracers were run to determine fracture height. The treating pressure data were also analyzed with a three-dimensional fracture model[10] to estimate fracture height.

Fig. 12 presents the mini-frac analysis results. The microseismic survey estimated the top of the fracture at between 7,350 and 7,400 ft, near the base of the Marble Falls Limestone. The tracer surveys, on the other hand, indicated the top of the fracture at 7,570 ft, at the base of the Forestburg Limestone. The treating pressure analysis placed the top of the fracture at 7,511 ft, just above the Forestburg Limestone in the Upper Barnett.[9] From these analyses, it is not certain where the actual top of the fracture is located, but both the treating pressure analysis and the tracer surveys suggest the Forestburg acts to restrict vertical fracture growth. The microseimic survey did not identify the bottom of the fracture, but the tracer surveys and treating pressure analysis placed the bottom of the fracture at 7,874 and 7,877 ft, respectively, which is at the top of the Viola Limestone.[9]

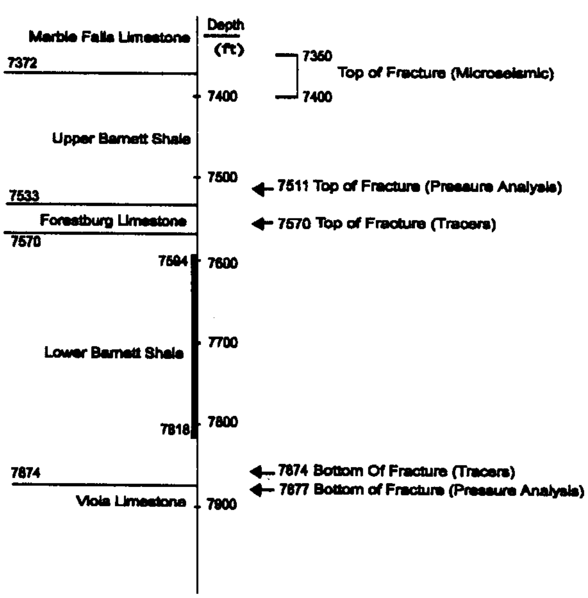


Fig. 12 - Mini-frac analysis results showing estimates of hydraulic fracture top and bottom.

The main fracture treatment on the Sims 2 include 52,000 gal of linear gel prepad, 658,000 gal of 40- to 30-lb/1000 gal of crosslinked gel, 13% nitrogen assist, and 1.35 million pounds of sand pumped down 5 1/2-in casing at 40 bbl/min. Again, the available surface pressures and rates were analyzed with a three-dimensional fracture model,[10] and a fracture half-length of over 1,200 ft was determined.[9] These results indicate that the large fracture treatments pumped in the Barnett. are resulting in long, reasonably contained hydraulic fractures being created and propped.

The post-fracture well performance from the Sims 2 illustrates the success of the large fracture treatment. The well has produced over 300 MMscf in less than one year after stimulation, and it is currently expected to produce about 1.5 Bscf over its life.

PRODUCTION DATA AND WELL TEST ANALYSES

Despite the detailed formation evaluation and stimulation analysis data collected on the Sims 2 well, no pre- or post-fracture well tests were performed. Thus, to get an idea of reservoir properties, such as permeability and fracture half-length, and to predict well performance, we analyzed a cross-section of available well tests and production data. We analyzed production data from six wells, including poor, average, and good producers; most of these wells had been on line for several years.[11]

Initially, we analyzed the production data using a single-phase, single-layer, analytical model[12] and our best estimates of net pay, porosity, and water saturation as determined from log analysis. Fig. 13 shows a history match of the production data from the Stella Young 4 well. The Young 4 well was completed in 1985 from 6,884 to 7,080 ft in the Lower Barnett. The well was fractured with 470,000 gal of 40- to 50-lb/1000 gal crosslinked gel, 300 scf/bbl nitrogen assist, and 875,000 lb of 20/40 mesh sand. The initial open-flow after stimulation was 5,400 Mscf/D. Through March 1991, the well had produced about 548.9 MMscf of gas and was flowing at a rate of approximately 164 Mscf/D. This is considered to be one of the better wells in the Barnett.

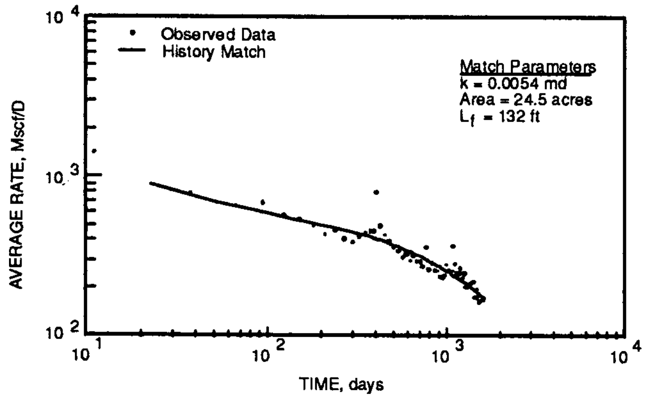


Fig. 13 - History match of Stella Young 4 production data using a single-layer, analytical model.

The production data match was obtained by varying estimates for permeability, fracture half-length, and drainage area. The production data were matched with a permeability of 0.0054 md (a permeability-thickness of about 1 md-ft), a drainage area of 24.5 acres, and a fracture half-length of 132 ft. As indicated by the deviation of the log-log plot from a straight line, the onset of boundary effects was also observed.

This match and these results were typical for all but one of the six wells analyzed.[11] Generally, (1) the permeability-thicknesses were reasonably consistent (about 1 to 2 md-ft), (2) the fracture half-lengths were short (about 100 to 200 ft), (3) apparent boundary effects were observed, and (4) the drainage areas were small (less than 25 acres). These results were puzzling and, in fact, they seemed unreasonable. Given that approximately one million pounds of sand was pumped into these wells on average, 100- to 200-ft fracture half-lengths seemed unlikely. In addition, as most of the drilling is still on 320-acre spacing in the area, the small drainage areas being computed were also questionable. On the basis of our experience in the Appalachian Devonian Shales, we expected that this initial, single-layer reservoir description was too simple,[13,14] and that the permeability distribution was highly variable throughout the large intervals of gas filled porosity (net pay).

Five pre-fracture and two post-fracture well tests were also available from the Barnett Shale.[11] Most of the pre-fracture well tests were difficult to analyze. Typically, the wells were flowed and shut-in for about 24 hours each, and these flow and shut-in times were insufficient to get beyond the effects of wellbore storage distortion. In addition, on the couple of tests where the wells were shut in longer, problems with the Amerada gauges used to collect the pressure data made some or all of the data useless or difficult to interpret.

Despite these problems, these data were analyzed using several different methods, and we estimated that the pre-fracture kh's ranged from 0.1 to 0.5 md-ft.[11] We also calculated small positive and negative skin factors (+2 to -2) from the pre-fracture tests. These results were not surprising, since the wells were broken down with acid prior to the tests to achieve a pre-stimulation flow rate.

The two post-fracture well tests, on the other hand, provided much better quality data to analyze. Both tests were run about a year after the wells went on line, so the flow times were sufficient. In addition, the shut-in times were longer, one week and nine weeks, respectively, which provided a little more data to work with. Unfortunately, there was not a pre-fracture well test run before either of these tests to provide a pre-fracture permeability estimate. That led to some uniqueness problems in the post-fracture analysis, but we still consider our interpretations of the post-fracture test data to be reasonable.

Fig. 14 illustrates the post-fracture test analysis from the Stella Young 4 well using the Cinco[15] type curves; this is the well whose production data analysis was discussed previously (Fig. 13). The interpretation of these data indicates a long, high conductivity fracture in this well. From the analysis, a kh of 1 md-ft and a fracture half-length of 476 ft were computed. This fracture half-length was much longer than what was computed from the production data analysis, given the same values for net pay, kh, porosity, and other reservoir properties. Note also in Fig. 14 that the late time data from this test begin to deviate above the type curve suggesting the onset of a reservoir heterogeneity or boundary effects during the test.[11]

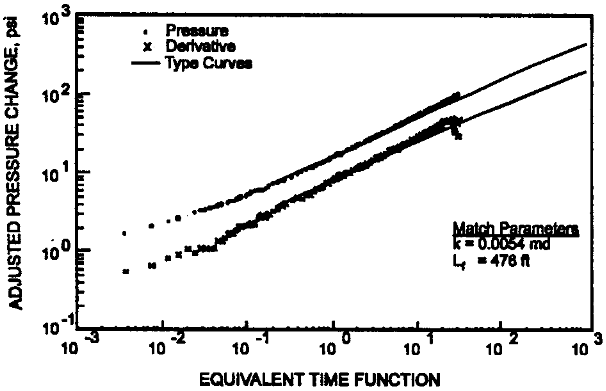


Fig. 14 - Post-fracture test analysis for Stella Young 4 using Cinco *et al.*[15] type curves.

As is apparent from these results, our initial analysis of both the production and post-fracture well test data from the Stella Young 4 resulted in different reservoir descriptions. Similar values were estimated for kh, but very different values were obtained for fracture half-length. What we desire is one reservoir description that describes both the production and well test data. In fact, as Fig. 15 shows, when the reservoir description developed from the production data analysis was used to predict the shape of the post-fracture buildup data, a poor comparison resulted. Given the discrepancy between these two sets of results and our experience with wells completed in the Appalachian Devonian Shales,[13,14] we concluded that a multi-layer model would be required to describe well performance from the Barnett Shale in the Stella Young 4 well.

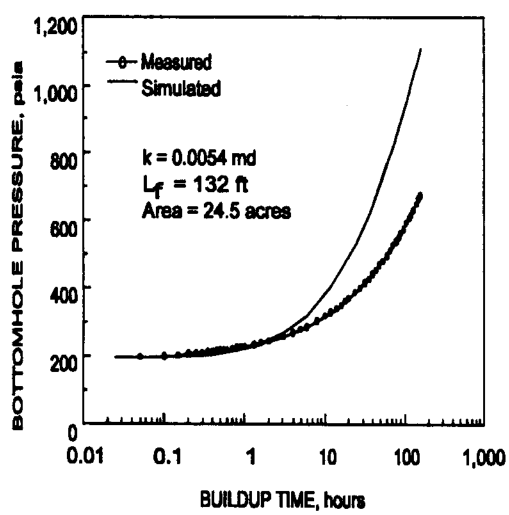
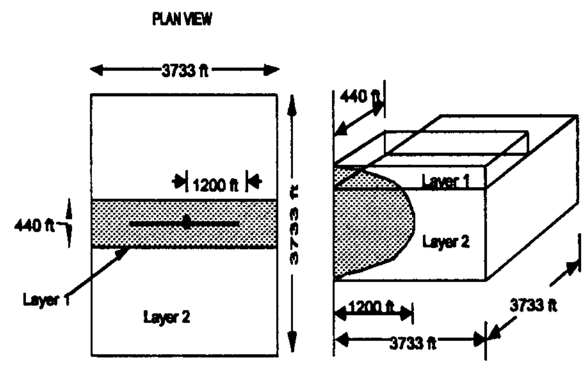


Fig. 15 - Single-layer reservoir description from Stella Young 4 production data analysis cannot reproduce post-fracture pressure buildup test data.

Fig. 16 illustrates the model used to match both the production and well test data from the Stella Young 4. Actually, it is a two-layer model. The upper layer, Layer 1, is a relatively thin, higher permeability layer that accounts for most of the well's productivity and short-term deliverability. The upper layer's productivity is, no doubt, enhanced by natural fractures, and it may be limited in areal extent. The lower layer, Layer 2, is a thicker, but lower permeability layer that contains most of the gas in place and is important to the well's long-term performance.



LAYER	k	h	ϕ_g	Area
	(md)	(ft)		(acres)
1	0.0025	22.5	0.076	38
2	0.00015	106.5	0.054	320

Fig. 16 - Two-layer model used to history match production and well test data from Stella Young 4.

Ideally, detailed core data or individual zone test data should be used for developing such a layered reservoir description. These data were not available for the Stella Young 4 well. Instead, the results of the Shale-specific log computation were used to distribute the Lower Barnett interval into layers; 8% and 5% porosity cutoffs were chosen somewhat arbitrarily. Using the 8% cutoff, we estimated a net pay of 22.5 ft and a gas porosity of 7.6% for the well. These properties were assigned to the high permeability layer. Using the 5% cutoff, a net pay of 129 ft and a gas porosity of 5.8% were computed. These values were used to represent the total pay thickness and gas porosity for the well. The difference between these two values, a net thickness of 106.5 ft and a corresponding gas porosity of 5.4%, were assigned to the lower productivity layer.[16] Using this approach, we then varied the permeabilities in each layer, the effective drainage area size and shape of each layer, and the fracture half-length in obtaining the final history match of the production and well test data. The history match was obtained using a single-phase, three-dimensional, finite-difference reservoir simulator.[18]

As Fig. 16 shows, the best match of both the production and well test data was obtained with a 1,200-ft fracture half-length contacting both (1) a low permeability layer (0.00015 md) draining a square, 320-acre area and (2) a higher permeability layer (0.0025 md) draining a rectangular (8.5x1), 38-acre area. The long axis of the drainage area for the high permeability layer is parallel to the direction of the hydraulic fracture. Fig. 17 shows the match of the production data, and Fig. 18 presents the match of the post-fracture buildup data generated using this reservoir description. Note that good matches of both the production data and the buildup data were obtained using this description.

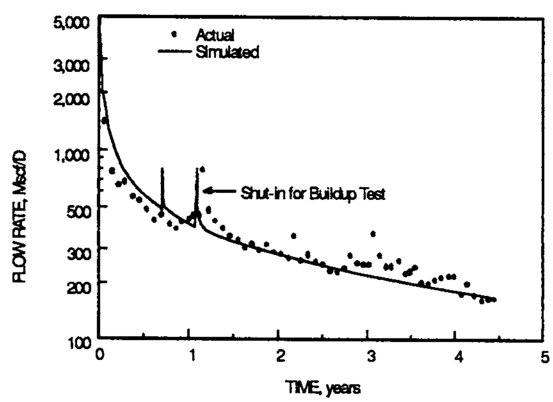


Fig. 17 - History match of post-fracture production data from Stella Young 4 using two-layer model.

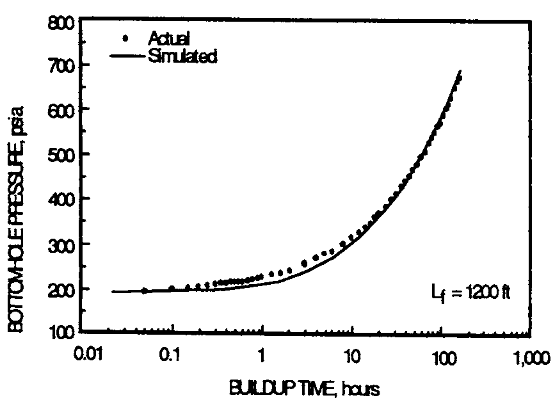


Fig. 18 - History match of post-fracture buildup test data from Stella Young 4 using two-layer model.

We expect that the dimensions of the two layers, and even the individual layer properties, are somewhat non-unique. Certainly, if different layer thicknesses were used, a different geometry for the upper layer drainage area might match the data equally well, or somewhat different layer permeabilities or another fracture half-length could be calculated. These results do show, however, that a two-layer model does a good job of describing the post-fracture production and pressure buildup test data from this Barnett Shale well.

These results are important for several reasons. First, this reservoir description is consistent with all we have learned about the Barnett Shale. The drainage area of the lower permeability layer is equal to the current well spacing in the field (although, due to the low permeability, the layer cannot be drained effectively in 20 years). Also, a long fracture half-length of 1,200 ft is reasonable considering the size of the fracture treatment pumped in the Young 4 well (875,000 lb of sand). Second, due to the layered permeability distribution, the well's short-term deliverability is controlled by the higher permeability layer, while the well's longer-term performance is strongly influenced by the lower permeability layer containing the majority of the gas in place. This reservoir description explains why analysis of the short-term well test data and the longer-term production data with only a single-layer model led to inconsistent results.

Finally, these results are further substantiated by the analysis of natural fracture occurrences reported for the Sims 2 well. As mentioned earlier, we observed that natural fractures in the Lower Barnett core tended to occur in distinct "clusters" (or layers) vertically, and that these natural fractures had limited vertical extent. This observation suggests that the natural fractures could occur as "sweet spot" fairways as indicated by the shape of the higher permeability layer in Fig. 16.

Using this reservoir description, we forecasted future recovery from the Stella Young 4 and determined that the well should recover 1.1 Bscf in 20 years; this is illustrated in Fig. 19. This recovery is in line with Mitchell's observations for what "good" Barnett Shale wells will make. Of this 1.1 Bscf, about 500 MMscf comes from the higher permeability layer; this is about 26% of the gas in place in that layer. About 600 MMscf comes the lower permeability layer, but this is only about 4% of the gas in place in that layer. Still, the lower permeability layer does contribute significantly to the overall gas recovery from this well. In addition, the 20-year well life is an arbitrary cutoff. The well should still be making 50 to 60 Mscf/D after 20 years, and depending on the economics, MEC may continue to operate the well, thereby increasing its ultimate recovery somewhat.

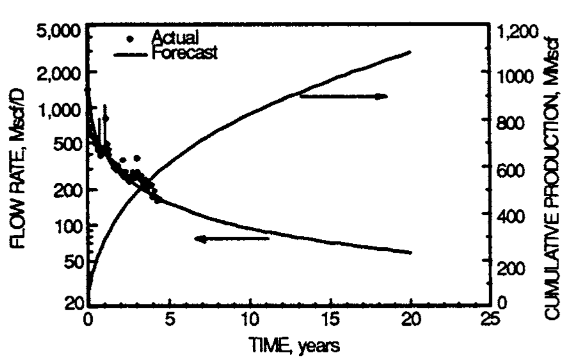


Fig. 19 - Well performance forecast for Stella Young 4 using two-layer model.

SUMMARY AND CONCLUSIONS

In summary, we have described the results of the evaluation, completion, stimulation, and testing of Barnett Shale wells operated by MEC in the Fort Worth Basin of north-central Texas. We have presented detailed analyses of data gathered from a GRI/MEC cooperative well that was used to obtain a better understanding of the mechanisms controlling gas production from the Barnett. We have also developed a plausible reservoir description for the Barnett Shale using these data, production data, and available well tests.

On the basis of our analyses of the data presented in this paper, we have reached the following conclusions.

1. Well performance in the Barnett Shale is best described with a layered reservoir description, where most of the well deliverability associated is associated with thinner, higher permeability, naturally fractured zones, while most of the gas in place is confined to thicker, extremely low permeability layers.

2. Core and FMS data suggest that the Barnett Shale is naturally fractured, but the natural fractures tend to occur in "clusters" (or layers) and appear to have limited vertical extent. The natural fractures are oriented northwest-southeast and intersect northeast-southwest trending induced fractures at an angle of about 67°.

3. Gas-in-place in the Lower Barnett Shale may average 10 to 12 Bscf per 160 acres, but the better wells are expected to produce only about 1 to 1.5 Bscf in a twenty-year well life.

4. Approximately 20% of the total gas in place in the Lower Barnett is adsorbed gas; however, desorption appears to become important only after the reservoir pressure falls below 1,000 psia. Gas storage at pressures above 1,000 psia appears to occur only as free gas in the pore spaces.

5. The large fracture treatments being used in the Barnett Shale are resulting in long, propped hydraulic fractures. These hydraulic fractures are typically contained within the Barnett by the limestone formations above and below.

NOMENCLATURE

A	Drainage area, acres
h	Net pay, ft
k	Permeability, md
kh	Permeability-thickness product, md-ft
L_f	Fracture half-length, ft
R_{ilm}	Medium resistivity, ohm-m
R_{ild}	Deep resistivity, ohm-m
R_{sfl}	Spherically focused log resistivity, ohm-m
ϕ_g	Gas porosity, fraction

ACKNOWLEDGMENTS

The authors wish to thank the Gas Research Institute who sponsored this work under GRI Contracts No. 5086-213-1446, 5086-213-1390, and 5091-221-2130. We also wish to thank the members of our staffs at S. A. Holditch & Associates, Mitchell Energy Corporation, ResTech Houston, and CER Corporation, as well as Juniata College, Patrick Lowry, and John Curtis, for their contributions to this work. Finally, we gratefully acknowledge the cooperation of Mitchell Energy Corporation for providing the wells and much of the data used in this work.

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