Modeling Production and Evaluating Fracture Performance in Unconventional Gas Reservoirs

Craig L. Cipolla

Abstract

This article examines issues with forecasting and evaluating production from unconventional gas reservoirs such as those in the Barnett shale. How can reservoirs be commercial with matrix permeability measured not in millidarcies or even microdarcies (10^{-3} md), but nanodarcies (10^{-6} md)—typically, 10 to 100 nanodarcies? The key is maximizing the reservoir area that is connected to the wellbore by creating a very large man-made-fracture network. But how do we create a fracture network? The answer is large-volume high-rate hydraulic-fracture treatments that use water and small-mesh proppant to "activate" or stimulate the existing natural fractures or rock fabric. The created fractures are far from the classic "planar" model; they are large, complex flow networks that typically encompass 50 acres or more where the rock has been "broken." Gas production is a function of the number and complexity of fractures created, the effective fracture conductivity, and the matrix permeability. Understanding the relationship between gas recovery and fracture complexity, fracture conductivity, and matrix permeability is a key component of economic shale-gas development. This article will highlight the application of reservoir simulation to model production in shale-gas reservoirs, providing significant insights into these relationships that can improve stimulation designs, completion practices, and field-development strategies. Currently, most shale-gas resources are being developed with horizontal wells, and the reservoir simulations in this article focus on horizontal completions.

Introduction

The exploitation of unconventional gas reservoirs has become an ever increasing component of the North American gas supply. Gas shales are organic-rich shale formations and are apparently the source rock as well as the reservoir. The gas is stored in the limited pore space of these rocks, and a sizable fraction of the gas in place may be adsorbed on the organic material. The success of the Barnett shale has led to the development of other shale plays in North America, including the Woodford, Haynesville, Fayetteville, and Marcellus. The natural-gas resource potential of gas shales is estimated to be between 500 and 1,000 Tcf (Arthur et al. 2008). Typical shale-gas reservoirs exhibit a net thickness of 50 to 600 ft, porosity of 2–8%, and total organic carbon (TOC) of 1–14%, and they are found at depths ranging from 1,000 to 13,000 ft. This article focuses on the Barnett shale, in north-central Texas, found at depths of 6,500 to 8,500 ft with 100 to 600 ft of net thickness, 4–5% total porosity, and 4.5% TOC. The basin covers 5,000 sq miles (3.2 million acres), and original gas in place is estimated at 50 to 200 Bcf/sq mile. Typical well spacing ranges from 60 to 160 acres, with estimated ultimate gas recovery of 1 to 10 Bcf/well.

The economic viability of unconventional-gas developments relies on effective stimulation of extremely-low-permeability rock, typically 10 to 100 nanodarcies (0.00001 to 0.0001 md). In most cases, economic production is possible only if a very-complex highly nonlinear fracture network can be created that connects a huge reservoir surface area to the wellbore effectively. Many conventional hydraulic-fracture treatments use high-viscosity fluids to reduce fracture complexity and promote planar fractures, allowing the placement of high concentrations of large proppant. However, stimulation treatments in shale reservoirs use low-viscosity fluid (water) to promote fracture complexity and to place very low concentrations of small proppant—a completely different approach from that of conventional hydraulic fracturing.

The widespread application of microseismic (MS) mapping has improved

Craig L. Cipolla, SPE, is Vice-President of Stimulation Technology for Carbo Ceramics. He advises Carbo and StrataGen on new and innovative applications of stimulation technology, leads consulting projects, and teaches courses on the application of fracturing software and fracture engineering. From 1996 to 2008, Cipolla was Vice-President of Engineering for Pinnacle Technologies. His worldwide experience includes the design and evaluation of hydraulic-fracturing treatments, tight-gas-reservoir engineering, integrated field studies, supervising stimulation treatments, and the application of MS and tiltmeter fracture-mapping technologies. Before joining Pinnacle, Cipolla held positions at Union Pacific Resources, CER Corporation, and Dresser Industries. He has coauthored many technical papers and was an SPE Distinguished Lecturer on hydraulic fracturing in 2005–06.

This is paper SPE 118536. **Distinguished Author Series** articles are general, descriptive representations that summarize the state of the art in an area of technology by describing recent developments for readers who are not specialists in the topics discussed. Written by individuals recognized as experts in the area, these articles provide key references to more definitive work and present specific details only to illustrate the technology. **Purpose:** to inform the general readership of recent advances in various areas of petroleum engineering.

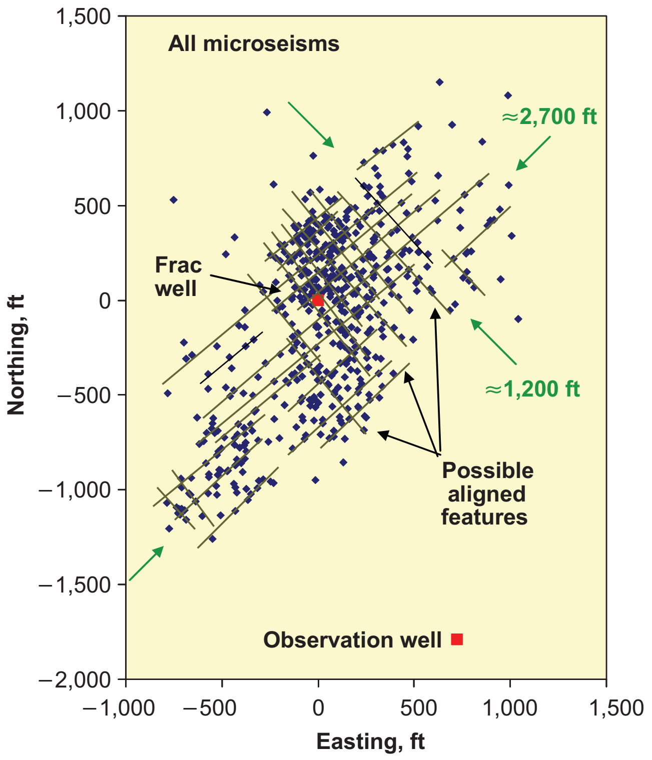


Fig. 1—MS-event pattern for a typical Barnett-shale water frac in a vertical well.

our understanding of hydraulic-fracture growth in unconventional gas reservoirs significantly, leading to better stimulation designs. Hydraulic-fracture growth in many unconventional reservoirs is very complex and unpredictable. **Fig. 1** shows a typical MS-event pattern for a Barnett-shale water-frac stimulation treatment, illustrating the complex fracture networks that are typical in many unconventional gas reservoirs (Fisher et al. 2005). The dots (MS events) show the spatial locations where the rock has been "broken" or fractured. The fracture network in Fig. 1 is extremely large, covering approximately 75 acres; connecting millions of square feet of reservoir surface area to the wellbore. Without this "picture" of the fracture, the extreme complexity of fracture growth in the Barnett shale may never have been understood—instead migrating back to the planar world reinforced by current fracture models. Although not the subject of this article, nonplanar hydraulic-fracture models are being developed to simulate these complex networks and improve stimulation designs. In general, the larger and more-complex the MS-event pattern, the better the production (Mayerhofer et al. 2008). The flow capacity or conductivity of the fracture network also is a critical parameter that affects gas recovery.

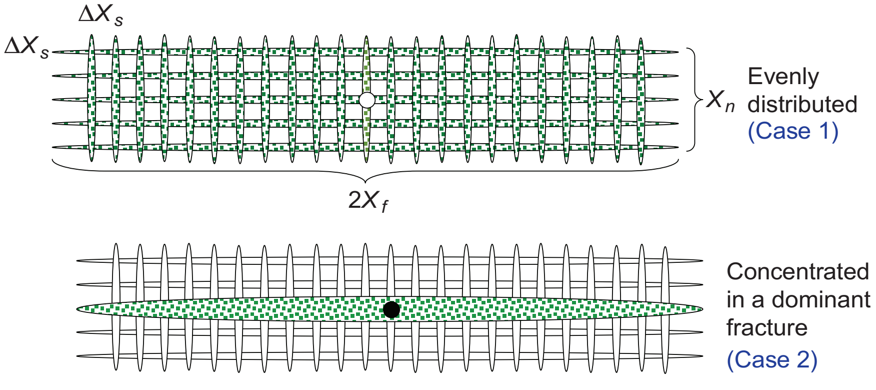


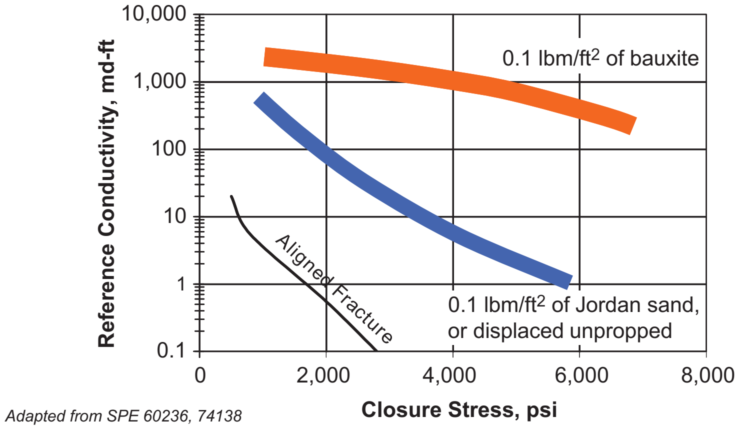
Fig. 2—Proppant-transport scenarios.

Where Is the Proppant, and What Is the Network Conductivity?

Although MS mapping can provide significant insights into fracture growth in shale-gas reservoirs, the overall effectiveness of stimulation treatments is difficult to determine from MS mapping alone because the location of proppant and distribution of conductivity within the fracture network cannot be measured (and these are critical parameters that control well performance). Therefore, it is important to develop reservoir models that simulate production from these complex reservoirs to evaluate well performance and improve stimulation designs and completion strategies. An essential aspect of modeling well performance in unconventional gas reservoirs is that of characterizing flow capacity or conductivity of the fracture network and the primary hydraulic fracture (if present). Three key questions need to be answered when trying to characterize the flow capacity of an induced-fracture network.

- Where is the proppant within the fracture network?
- What is the conductivity of the propped-fracture network?
- What is the conductivity of the unpropped-fracture network?

Unfortunately, proppant transport cannot be modeled reliably when fracture growth is complex, making it very difficult to predict the location of proppant within a fracture network. However, the location of proppant within the fracture network can be estimated by use of two limiting scenarios: (Case 1) the proppant is evenly distributed throughout the complex fracture system or (Case 2) the proppant is concentrated in a dominant primary fracture that is connected to an unpropped complex fracture network. **Fig. 2** shows the two proppant-distribution scenarios. Recent studies have shown that if the proppant is distributed evenly in a complex fracture network (Case 1), then the concentration of proppant would be insufficient to affect network fracture conductivity materially. In other words, there is insufficient proppant pumped to prop extremely large fracture networks effectively and the fractures would behave as if they were unpropped.



Adapted from SPE 60236, 74138

Fig. 3—Unpropped- and partially-propped-fracture conductivity.

If the proppant is concentrated in a dominant primary fracture (Case 2), the average proppant concentration would be significantly greater. This case should result in much higher conductivity in the primary fracture and a better connection between the fracture network and the wellbore, which could significantly improve productivity. However, there would be no proppant in the fracture network. In either case, well productivity in unconventional gas reservoirs may be dominated by the conductivity of unpropped or partially propped network fractures. Therefore, it is very important to understand the conductivity of unpropped and partially propped network fractures.

Fig. 3 shows laboratory tests that approximate the conductivity of partially propped and unpropped fractures as a function of closure stress. The conductivity estimates are probably typical for many shale-gas reservoirs (adopted from Fredd et al. 2001). The bottom curve shows the conductivity for an unpropped fracture where the two fracture faces are aligned upon closing. If the fracture faces are aligned, unpropped fractures will have very low conductivity at closure stresses in excess of 3,000 psi that are experienced in most shale reservoirs. However, if the faces of the fracture are displaced because of shear offsets or the fracture is partially propped with 0.1 lbm/ft^2 of sand, fracture conductivity would be improved significantly (blue curve). Unfortunately, sand proppants crush easily under the extremely high stress on the individual particles when the fracture is only partially propped (partial monolayer). Fracture conductivity can be improved significantly if the fracture network is partially propped with a high-strength proppant such as sintered bauxite (orange curve). Because typical fracture treatments in shale reservoirs likely will result in proppant concentrations much less than 0.1 lbm/ft^2 in the fracture network, it is unlikely that partial propping with sand proppant will improve conductivity materially in most cases because of crushing. However, it is possible that some shear offset could occur, displacing the fracture faces and resulting in unpropped-fracture conductivity of 0.5 to 5 md-ft in many shale-gas reservoirs. These estimates of unpropped-network conductivity provide a starting point to evaluate well performance and stimulation designs. The next step is integrating the unpropped conductivity data, estimates or special laboratory measurements of matrix permeability, and knowledge gained from MS mapping with reservoir modeling to evaluate stimulation designs and completion strategies.

Modeling Well Performance

Gas flow from ultralow-permeability rock through the complex fracture network must be modeled to evaluate stimulation designs and completion strategies properly. Therefore, the complex fracture network and primary hydraulic fracture (if present) must be characterized discretely in reservoir-simulation models. MS fracture mapping provides a measurement of the overall stimulated-reservoir volume (SRV) and special core analysis can provide values for matrix permeability. With these two parameters, reservoir-simulation models can be used to estimate the spacing of network fractures (complexity) and their conductivity. Simulated production profiles then can be compared to actual well performance to evaluate the effectiveness of stimulation designs and completion strategies and to diagnose the relative conductivity of the primary fracture (if present). The following simulations assume reservoir and fracture properties typical of the Barnett shale, but the modeling approach and many of the insights gained should be applicable to many unconventional gas reservoirs. The initial simulations assume a uniform-conductivity fracture network (Case 1 in Fig. 2), where the conductivity of the primary fracture is equal to the network conductivity (i.e., a primary fracture is not present). The effect of a primary fracture with high conductivity relative to the network fractures will be discussed later.

Fig. 4 shows a typical pressure distribution for a horizontal-well completion after 1 year and 15 years of production in an unconventional gas reservoir. The pressure distribution is shown for one-half of the reservoir (half-symmetry simulation model). Red denotes original reservoir pressure, and dark blue represents flowing bottomhole pressure. In this

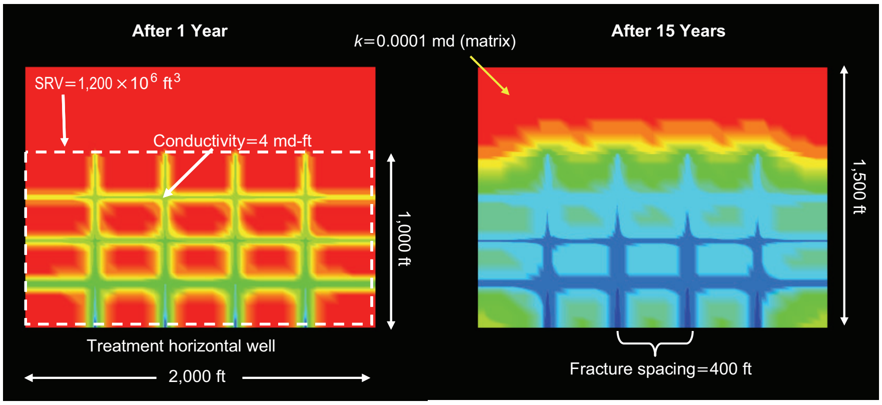


Fig. 4—Pressure distribution in an unconventional gas reservoir.

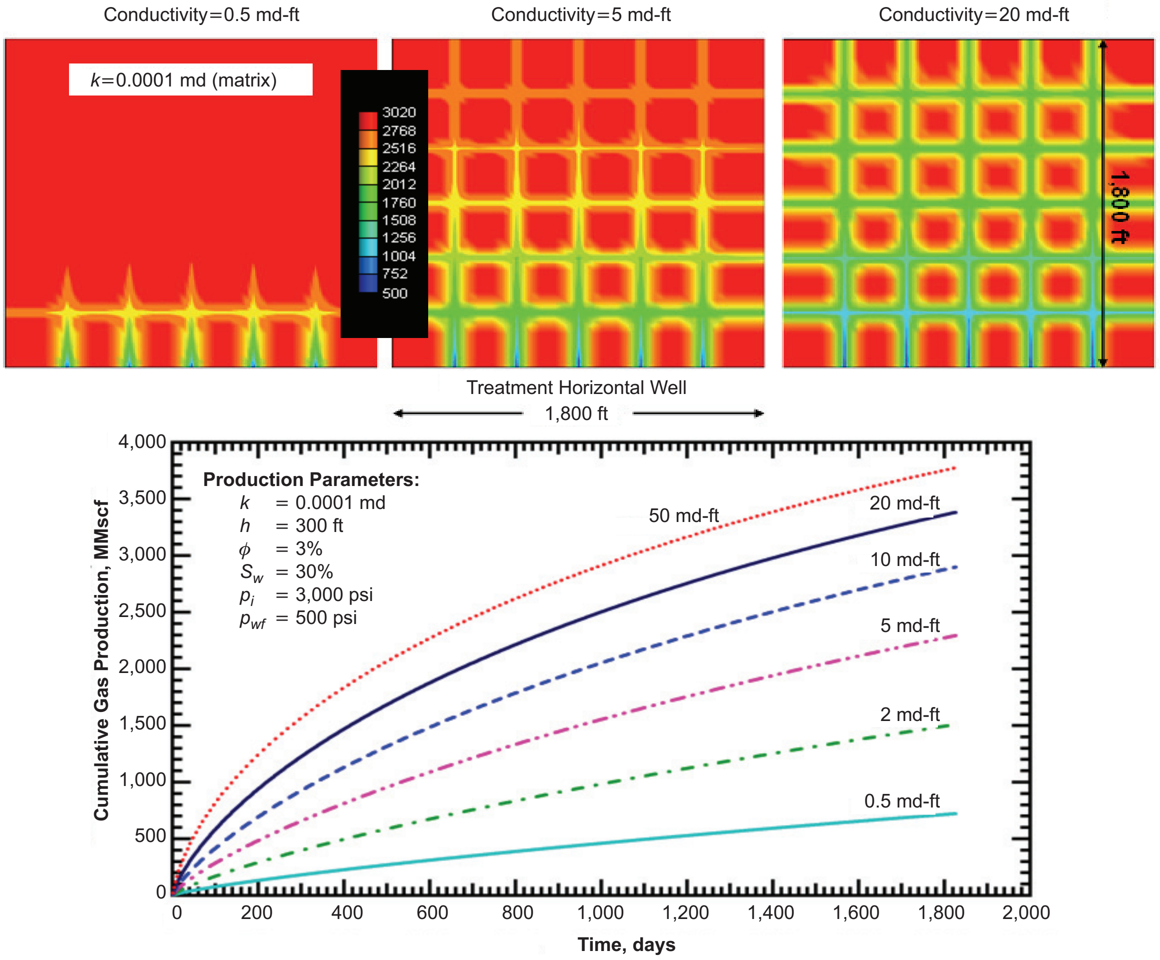


Fig. 5—Effect of network-fracture conductivity.

example, hydraulic fractures are placed in a horizontal well and spaced 400 ft apart, with the secondary network fractures represented as 250-ft square blocks with a network-fracture conductivity of 4 md-ft. The fracture network extends 1,000 ft on each side of the horizontal well. After 1 year, gas production is limited to the reservoir area directly adjacent to the network fractures, and after 15 years, gas drainage is limited to the proximity of the network. This example illustrates that because of the very low matrix permeability (0.0001 md), gas recovery is limited to the area in which an effective fracture network is generated. By modeling these complex fracture networks, the effect of stimulation designs and completion strategies can be studied.

Network Size, Fracture Spacing, and Network-Fracture Conductivity

Reservoir modeling has shown that gas recovery can improve dramatically if the SRV can be increased. This knowledge has resulted in pumping very large water-frac stimulation treatments in unconventional gas reservoirs, with typical multistage treatments in horizontal wells totaling 5 million gal of water and 750,000 lbm of proppant. In addition, gas recovery can be accelerated significantly and drainage improved markedly if more-complex fracture networks can be created (i.e., smaller network-fracture spacing). Insights gained from reservoir modeling have lead to fracture-treatment designs and completion strategies aimed at maximizing fracture complexity, including closer spacing of perforation clusters and more fracture treatments in horizontal wells, the use of small proppants to divert treatment fluid and create new fractures, higher injection rates, closer spacing between laterals, and simultaneous or alternating fracture treatments in offsetting horizontal wells to focus the stimulation energy.

The effect of network-fracture conductivity on gas production is shown in **Fig. 5.** The top portion of the figure shows the pressure distribution in the reservoir after 1 year for fracture conductivities of 0.5, 5, and 20 md-ft, illustrating that the very tight reservoir matrix cannot be drained effectively when fracture conductivity is too low. The bottom portion of the figure shows the cumulative gas production for fracture conductivities ranging from 0.5 to 50 md-ft, emphasizing the dramatic effect network-fracture conductivity can have on well performance and gas recovery. Fracture conductivity of 50 md-ft or higher may be required to maximize production rate and gas recovery in this complex fracture network, even when matrix permeability is 0.0001 md.

The effect of network-fracture conductivity on well performance and the likelihood that much of the fracture network may not be propped effectively has led to laboratory studies to quan-

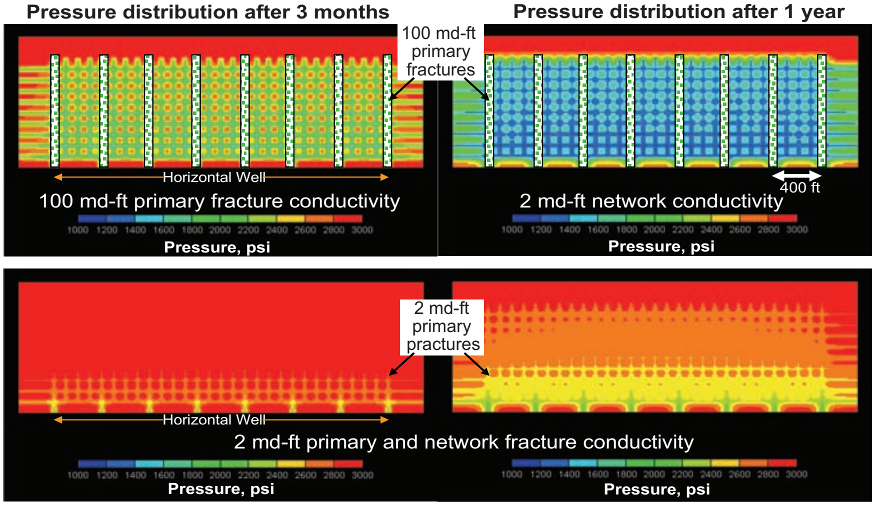


Fig. 6—Effect of primary-fracture conductivity.

tify likely ranges for unpropped- and partially-propped-fracture conductivity. To improve network-fracture conductivity, experiments with treatment designs have included increased proppant volumes, higher-strength proppants, and smaller proppants that may be transported deeper into the fracture network.

Primary-Fracture Conductivity and Spacing

Previous reservoir simulations assumed that proppant was distributed evenly throughout the fracture network and that conductivity was dominated by unpropped or partially propped fractures. However, proppant may not be transported effectively into complex network fractures and may be contained in a primary or dominant fracture (Case 2 in Fig. 2). In this limiting case, the conductivity of the primary fracture would be determined by the type and concentration of the proppant in the fracture, while the network fractures would be unpropped.

Fig. 6 shows the effect of primary-fracture conductivity on gas recovery in unconventional gas reservoirs (Cipolla et. al. 2009). In these simulations, a cased-and-cemented horizontal completion is modeled with fracture treatments every 400 ft (primary fractures) and 100-ft square matrix blocks with 2-md-ft network-fracture conductivity. The matrix permeability is 0.0001 md, original reservoir pressure is 3,000 psi, and flowing bottomhole pressure is 1,000 psi. The top portion of Fig. 6 shows the pressure distribution in the reservoir after 3 months and 1 year when the primary-fracture conductivity is 100 md-ft, possibly representing a case in which proppant is contained mostly within the primary fracture and is not transported into the adjacent fracture network. When the primary-fracture conductivity is relatively high, drainage from the very tight matrix is very efficient. The bottom portion of Fig. 6 shows the pressure distribution when the primary-fracture conductivity equals the network-fracture conductivity (uniform conductivity of 2 md-ft), representing the case in which proppant is distributed evenly throughout the large fracture network. In the absence of a relatively-high-conductivity primary fracture, drainage is much less effective and pressures in the reservoir are significantly higher.

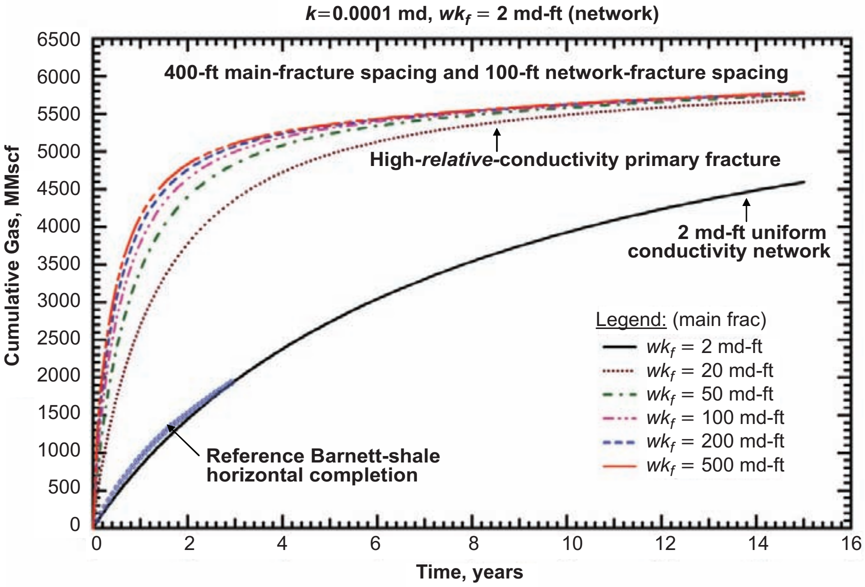


Fig. 7—Effect of primary-fracture conductivity.

The effect of primary-fracture conductivity on 15-year gas recovery in unconventional reservoirs is shown in **Fig. 7,** showing that gas recovery is significantly lower without a relatively-high-conductivity primary fracture (uniform network conductivity of 2 md-ft). The figure shows that gas recovery can be accelerated significantly even when primary-fracture conductivity is as low as 20 md-ft, while primary-fracture conductivity above 100 md ft provides little additional production benefit. The production profiles are significantly different when a high-relative-conductivity primary fracture is present compared to the uniform-conductivity network. Insights into current completions may be possible by comparing actual production profiles to the simulated gas recoveries for these two cases. The gas recovery for a reference Barnett-shale horizontal-well completion is shown in Fig. 7 for comparison. The reference well has an SRV and completion comparable to the reservoir-simulation model. This well exhibits a production profile that follows the simulation results for a uniform-conductivity network, indicating that a high-relative-conductivity primary fracture may not be present.

Fig. 8 shows the effect on gas production of the spacing between the primary fractures in a horizontal-well completion. The spacing between the primary fractures in a cased-and-cemented horizontal well is a function of the number of fracture-treatment stages that are pumped. The spacing of the matrix or network blocks is 100 ft, and the fracture-network conductivity is 2 md-ft (unpropped) for all cases. The simulations also illustrate the effect of a high-relative-conductivity (200 md-ft) primary fracture. The figure shows that if a high-relative-conductivity primary fracture can be created, the effect of primary fracture spacing is small. However, if a high-relative-conductivity primary fracture cannot be created, then reducing the spacing between the primary fractures by pumping more fracture-treatment stages will affect production rates and gas recovery materially. The implications of these results are significant. In addition to large increases in production, the number of fracture-treatment stages may be reduced if a high-relative-conductivity primary fracture can be created, resulting in potential cost savings. The production from two horizontal Barnett wells is shown on Fig. 8 for comparison to the reservoir-simulation results (the upper curve is the same as in Fig. 7). The SRV from MS mapping for these wells is similar to that used in the reservoir model. The two wells follow the production trend for a 2-md-ft uniform-conductivity network with primary-fracture spacing of 500 to 600 ft. The actual spacing of the primary fractures in these wells was 500 to 700 ft. Production data for these two wells indicate that a high-relative-conductivity primary fracture was not created and that significant potential increases in production rates and gas recovery may be possible by changing stimulation designs. Design changes that are being trialed or that have been proposed include pumping lower-density higher-strength proppants and pumping larger proppants at the beginning and/or end of the fracture treatment. Larger proppants may be less likely to enter the network fractures and more likely to accumulate in the primary fracture, increasing primary-fracture conductivity.

Nonuniqueness, Simplifications, and Uncertainties

As fracture complexity increases, it becomes more difficult to obtain unique solutions when evaluating well performance. There is a limited amount of special core analysis available to estimate matrix permeability and unpropped-fracture conductivity in unconventional gas reservoirs, and these tests have their own uncertainties. Although MS mapping can provide much information about the volume of rock that has been stimulated and provide insights into fracture complexity, it cannot provide a detailed description of the spacing of the network fractures or of the location of the proppant. In addition, shale-gas-reservoir models often neglect water production and gas desorption to simplify the simulations. Therefore, it may not be possible to determine matrix permeability, network block size and conductivity, and primary-fracture conductivity accurately by history matching production. However, it may be sufficient to develop reasonable ranges for these parameters and evaluate their effect on well performance, identifying basic production trends that can provide critical insights to improve stimulation designs and completion strategies. The comparisons shown in Figs. 7 and 8 are examples of identifying production trends. Although there is uncertainty in the parameters, it appears clear that a high-relative-conductivity primary fracture is not present in these two Barnett wells, and, therefore, opportunities may exist to improve well performance.

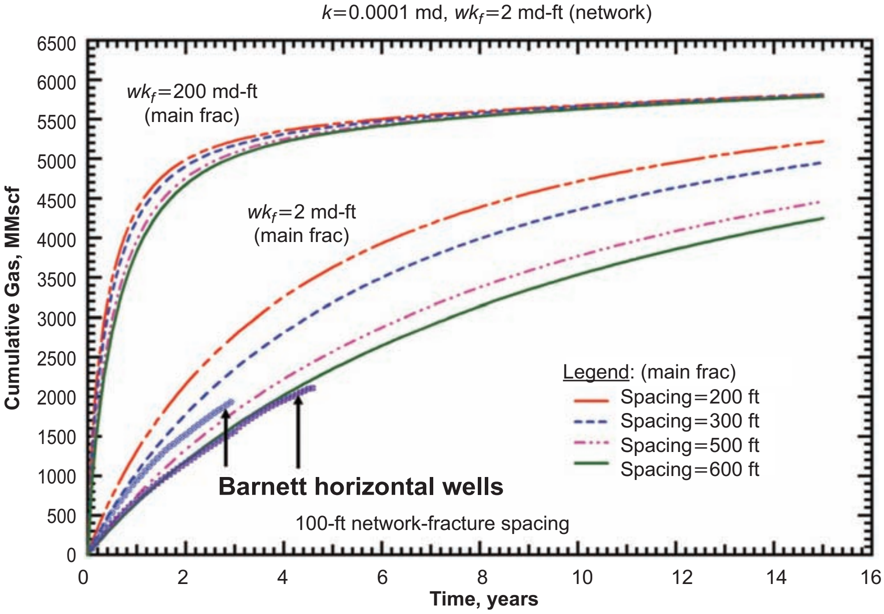


Fig. 8—Effect of primary-fracture spacing.

Fig. 9 shows the effect of uncertainties in matrix permeability. Cumulative production is shown for a matrix permeability of 0.00001 md; previous simulations assumed a matrix permeability of 0.0001 md. The primary-fracture spacing is 600 ft, and the network-fracture spacing ranges from 50 to 300 ft. A uniform network conductivity of 2 md-ft was modeled. As would be expected, gas recovery increases as network-fracture spacing becomes smaller. For comparison, the production for 50-ft (red dots) and 100-ft (blue dots) network-fracture spacing and 0.0001 md matrix permeability is plotted on Fig. 9, illustrating that similar production profiles can be obtained for vastly different matrix permeability with different assumptions for network-fracture spacing. Even more interesting is that when network-fracture spacing is 50 ft, the effect on gas recovery is less than 10% for a 10-fold change in matrix permeability. This result would indicate that very-tight-matrix rock may be drained efficiently if very complex fracture networks can be created (i.e., small network blocks). The production data for the two reference Barnett horizontal wells are shown on Fig. 9 also, and the trend still indicates that a high-conductivity primary fracture is not present. Although not shown on Fig. 9 for the 0.0001-md-matrix cases, a high-conductivity primary fracture would result in significant acceleration of gas recovery.

Summary

Recent advances in MS fracture-mapping technology provide previously

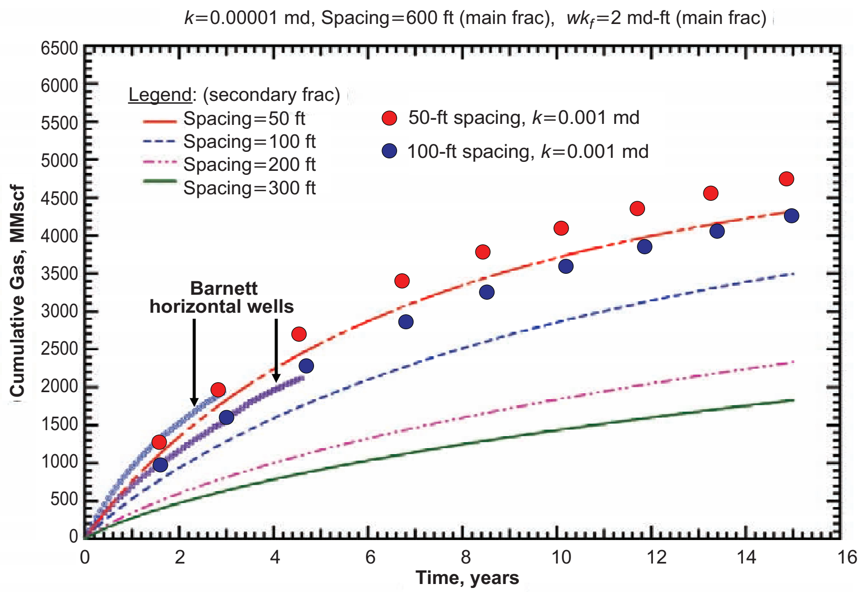


Fig. 9—Effect of matrix permeability.

unavailable information to characterize hydraulic-fracture growth and show surprising complexities in many geological environments. To date, the most complex fracture growth has been documented in unconventional gas reservoirs, such as the Barnett shale. Understanding hydraulic-fracture growth was key in commercializing the vast unconventional gas resources in North America. The next step in understanding unconventional gas reservoirs was to develop reservoir-modeling approaches to study production mechanisms, improve stimulation designs, and maximize gas recovery and economic return.

The use of MS-mapping data to characterize the size and complexity of the fracture network and special core measurements of unpropped-fracture conductivity and matrix permeability can provide critical parameters needed for reliable reservoir modeling of unconventional gas reservoirs. Integrating this information with reservoir simulators for discrete modeling of the very tight rock matrix, complex unpropped-fracture network, and primary fracture (if present) can identify opportunities to improve stimulation designs and completion strategies.

Current completion trends in many unconventional gas reservoirs are aimed at maximizing the reservoir area connected to the wellbore by use of horizontal wells with multiple hydraulic-fracture-treatment stages. However, there also is an optimization component of this process in which reservoir modeling can aid in determining how much reservoir area can be drained effectively by each horizontal well. The conductivity and complexity of the network fractures and the ability to create a high-conductivity primary fracture will significantly affect how much gas can be drained from each well effectively, which will affect well-spacing and -placement decisions.

The application of reservoir modeling has led to a better understanding of the primary factors that affect well performance in unconventional gas reservoirs. Understanding these key production mechanisms has led to increases in the amount of fluid and proppant pumped, innovative completion strategies (such as simultaneous fracture treatments in offsetting wells), novel diversion techniques with proppants, and/or more fracture-treatment stages—all in an attempt to increase the size and complexity of the fracture network. Understanding the importance of network- and primary-fracture conductivity has resulted in experimentation with lower-density, stronger, and/or smaller proppants plus unique proppant scheduling with multiple proppant sizes to improve both network- and primary-fracture conductivity.

As our understanding of unconventional gas reservoirs advances, it is likely that significant improvements in stimulation designs, completions strategies, and overall resource development will be possible. An important component of this effort will be the continued development of reservoir-modeling approaches that describe the complex production mechanisms in these reservoirs accurately.

Nomenclature

h = thickness, ft
k = permeability, md
p_i = initial pressure, psi
p_{wf} = flowing bottomhole pressure, psi
S_w = water saturation, %
wk_f = fracture conductivity, md-ft
X_f = fracture half-length or network half-length, ft
X_n = fracture network width, ft
ΔX_s = fracture-network block size (square blocks), ft
ϕ = porosity, %

References

Arthur, J.D. Bohm, B., and Layne, M. 2008. Hydraulic Fracturing for Natural Gas Well of the Marcellus Shale. The Ground Water Protection Council 2008 Annual Forum, Cincinnati, Ohio, 21–24 September.

Cipolla, C.L., Warpinski, N.R., Mayerhofer, M.J., and Lolon, E.P. 2009. The Effect of Proppant Distribution and Unpropped Fracture Conductivity on Well Performance in Unconventional Gas Reservoirs. Paper SPE 119366 presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, 19–21 January. doi: 10.2118/119366-MS.

Fisher, M.K., Wright, C.A., Davidson, B.M., Goodwin, A.K., Fielder, E.O., Buckler, W.S., and Steinsberger, N.P. 2005. Integrating Fracture-Mapping Technologies To Improve Stimulations in the Barnett Shale. *SPE Prod. & Fac.* **20** (2): 85–93. SPE-77441-PA. doi: 10.2118/77441-PA.

Fredd, C.N., McConnell, S.B., Boney, C.L., and England, K.W. 2001. Experimental Study of Fracture Conductivity for Water-Fracturing and Conventional Fracturing Applications. *SPE J.* **6** (3): 288–298. SPE-74138-PA. doi: 10.2118/74138-PA.

Mayerhofer, M.J., Lolon, E.P., Warpinski, N.R., Cipolla, C.L., Walser, D., and Rightmire, C.M. 2008. What is Stimulated Rock Volume? Paper SPE 119890 presented at the 2008 SPE Shale Gas Production Conference, Fort Worth, Texas, 16–18 November. doi: 10.2118/119890-MS.

JPT