Barnett Shale gas production, Fort Worth Basin: Issues and discussion

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ABSTRACT

Newark East (Barnett Shale) field, Fort Worth Basin, Texas, is currently the most productive gas field in Texas in terms of daily production and is growing at an annual rate of more than 10%. However, despite the fact that the Barnett play has been studied intensely by very capable geologists and engineers from several companies over a period of many years, there continues to be several misunderstandings concerning fundamental factors controlling the success of the Barnett play of north Texas.

Barnett gas production is poorer in areas near faults and structural flexures (anticlines and synclines). Fractures, which are most abundant in these structural settings, are detrimental to Barnett production. Open natural fractures are rare in the Barnett and have little or nothing to do with Barnett productivity. In areas where Barnett Shale is thermally mature with respect to gas generation, it is slightly overpressured (about 0.52 psi/ft [11.76 kPa/m]). Limestone beds within the Barnett formation are the product of debris flows that originated on a carbonate shelf to the north of the present basin center. It appears that the Barnett can be used as an exploration model for other basins, especially analogous basins of the Ouachita trend.

The history of the development of the Barnett reservoir in north Texas provides an excellent example of how persistence can lead to success in nonconventional gas plays.

INTRODUCTION

In December 2001, Newark East (Barnett Shale) field in the Fort Worth Basin became the largest single producing gas field in Texas (in terms of daily production). Currently, the field is producing...
more than 1.3 bcf/day of gas, and annual production growth is substantially higher than 10%. More than 99% of Barnett production in north Texas is from the Newark East field. Several individuals who have worked in the Barnett play believe that the greater Newark East field will eventually surpass the Hugoton field of Kansas, Oklahoma, and Texas as the largest onshore gas field in the conterminous United States. However, despite being studied intensely by very capable geologists and engineers from several companies over a period of many years, contention and misunderstandings surrounding several fundamental issues concerning Barnett production continue. In this article, I review several of these contentious issues. I have had discussions with numerous geologists and engineers that are familiar with the Barnett play; to many of them, it appears simple: it is a fractured-shale play, just like other producing gas-shale reservoirs. However, the Barnett is not like the Antrim, Lewis, New Albany, the Devonian shale production of the Appalachian Basin, or any other productive shale in the United States. An exception may be the recent success in the Fayetteville Shale of the Arkoma Basin, but additional data from that nascent play are needed before that can be determined. I do not believe anyone currently understands the true complexity of the largest producing gas field in Texas; but one thing is certain; it is not just a fractured-shale play. Several factors, however, are key elements that make the Barnett such a prolific reservoir.

The purpose of this article is to clarify many of the misconceptions among the cadre of Barnett workers and to illuminate some of the unresolved issues so that those pursuing the Barnett play may benefit from the collected knowledge of geologists and engineers who, although not currently working on the Barnett, are familiar with these unresolved issues because of previous experience with similar unconventional reservoirs.

A vast literature exists (e.g., Wignall, 1994) concerning organic-rich shales that is little used by most involved in Barnett or other shale-gas plays. In particular, the Russian literature is an excellent source of research and information on black shales (e.g., Yudovich and Ketris, 1997, with 4931 references, half in Russian).

Some basic understanding of the Barnett Shale gas play will be required for the reader to place the issues discussed here into their proper context. Articles by Bowker (2003), Pollastro (2003), and Montgomery et al. (2005), and articles in this volume that review the basic geology and engineering of the Barnett will aid the general reader in understanding the issues discussed here.

**RELATIONSHIP OF OPEN NATURAL FRACTURES, FAULTS, AND STRUCTURAL FLEXURES TO PRODUCTION**

**Introduction**

The subject of open natural fractures is the most contentious within the community of Barnett workers. When first working with the Barnett Shale, many, including me, have presumed that open natural fractures are critical to Barnett gas production even when informed by experienced colleagues that this is not the case. In fact, if there was an abundance of open natural fractures within the Barnett, there would be a much smaller gas accumulation present within the reservoir. Open natural fractures, if they existed, would have led to major expulsion and migration of gas out of the shale into overlying rocks, substantially decreasing pore pressure within the Barnett and, hence, the amount of gas in place. The Barnett would not be overpressured (that is, overpressured relative to the bounding strata) if copious open natural fractures existed. Note that the Barnett is not just the gas reservoir, but also the source, trap, and seal for the gas; if the seal is fractured and inefficient, then the present gas in place would be much less because the free gas would be lost, and only the adsorbed gas would remain in the shale (a similar situation to that of the Antrim Shale of northern Michigan).

The initial exploration and exploitation strategy for many operators new to the play (including Mitchell Energy and Chevron when they first entered the play) is to test the Barnett near faults, with the assumption that there is increased natural fracture density (i.e., higher permeability) in these areas. This assumption is true: the density of natural fractures is highest near faults, but they are invariably completely healed with carbonate cements. Matrix porosity present in the Barnett near faults is also partially occluded with calcite (i.e., there is lower matrix porosity) near faults. The history of fracture-filling cementation within the Barnett has not been studied, but it is apparent from the macroscopic precipitation banding present in the larger fractures that there were several episodes of fracture filling. This evidence indicates that fractures were once open, but hot, mineral-laden water, probably from the underlying Ellenburger and possibly Viola (see Hill et al., 2007, for a stratigraphic column of the basin), moved up through the fractures, forming these carbonate cements (Bethke and Marshak, 1990).
Open Natural Fractures

It generally takes about 2–3 yr of experience in the Barnett Shale play of north Texas for the geologist or engineer to realize that open natural fractures are insignificant to the productivity of the Barnett. Open natural fractures are of little importance to Barnett production because they do not exist (except in very rare and isolated examples; I have only observed three open natural fractures, each about 0.5 in. [1 cm] long, in the hundreds of feet of core I have examined). That is not to say that natural fractures are not abundant in Barnett cores; they are, but they are nearly always healed with cement, commonly calcite (this counters the argument that we do not see the open natural fractures because we are relying on a vertical core, an orientation that presumably would reduce the odds of finding natural, near-vertical, fractures). Our natural bias as conventionally trained engineers and geologists is to identify a fracture-permeability network that will transmit gas from the matrix of the rock to the wellbore. The usual logic of those new to the Barnett is that induced fractures created during completion operations must enhance the existing open natural-fracture network. The matrix permeability of the Barnett is measured in nanodarcys, so it appears that this rock is too tight to transmit the large volumes of gas produced without the aid of natural open fractures. To envision how gas could move through such dense shale (which has the lowest matrix permeability of any strata within the sedimentary column of the Fort Worth Basin) without the presence of open natural fractures is difficult. How can one of the most productive reservoirs in Texas also be the least permeable?

Open natural fractures may not be a factor in Barnett gas production, but several completion engineers active in the Barnett believe that the healed natural fractures act to enhance the effectiveness of the induced fracture treatments (e.g., H. L. Matthews and R. Suarez-Rivera, 2004, personal communication). Their argument is persuasive: the healed fractures act as zones of weakness that serve to deflect the growing induced fracture. The following thought experiment helps to illustrate the point (R. Suarez-Rivera, 2005, personal communication). If one drills a hole in a thick block of glass that is under anisotropic lateral strain and then pressurizes the hole with water, the glass will crack along a single plane. However, if we first shatter the glass and then glue the pieces back together perfectly (so that there are no remaining voids) and repeat the procedure, the block of glass will fracture along many planes. The presence of open natural fractures would actually inhibit the growth of induced fractures. When a crack forms in a steel beam or piece of sheet metal, the propagation of the fracture can be halted by drilling a hole at the tip of the fracture. By eliminating the stress point at the tip of the fracture, the stresses causing the propagation of the fracture are dispersed, and the fracture no longer grows.

I believe that the combination of diffusion, a very high gas concentration within the Barnett, and the rock’s ability to fracture is what makes the play successful. The Barnett is not a fractured-shale play; it is a shale-that-can-be-fractured play (D. Miller, 2004, personal communication).

Faults and Structural Flexures

As noted above, the Barnett is highly fractured near major fault zones. These fractures, although now healed, appear to weaken the physical integrity of the Barnett within the fault zone. This weakness, in turn, allows the energy and fluid from our hydraulic-fracture stimulations to be diverted along the fault plane and into the underlying, commonly more porous, and commonly water-saturated Ellenburger Group carbonates. Several companies have drilled wells as close as 500 ft (152.4 m) to known major fault zones where induced fractures did not propagate into Ellenburger water, but wells located within fault zones have not been successful to date.

On average, wells located on structural flexures (anticlines and synclines) and karst tend to be poorer producers than those not associated with structures (Zhao, 2004). Again, because of natural fractures in these structural folds, hydraulic-fracture stimulations may not be contained within the Barnett, but may be diverted downward into underlying Viola and/or Ellenburger formations, thus resulting in the Barnett being understimulated.

GAS GENERATION VERSUS PRESSURE PRESERVATION IN NONCONVENTIONAL RESERVOIRS: THE SOURCE OF OVERPRESSURE IN THE BARNETT SHALE

A debate has been ongoing among respected colleagues concerning the overpressure found in various gas basins (including the Greater Green River and Fort Worth
basins). The debate centers on a central issue: the cause of present-day overpressuring in some basin-centered (continuous-type) gas deposits. Generally, two hypotheses are championed to explain this phenomenon.

Hypothesis 1

The overpressured formations, which are commonly not only the reservoir but also the source rock for the gas, are in the hydrocarbon-generation window. For example, the Barnett reservoir (and, hence, hydrocarbon source) in Newark East field currently averages approximately 180°F (82°C), putting it barely into the hydrocarbon-generating window. The Barnett has an average total organic carbon (TOC) within the field of 4.5 wt.%, classifying it as very rich. Therefore, hydrocarbons are currently being generated within the Barnett, thus causing overpressure. This hypothesis is commonly promulgated by workers that have a difficult time understanding the mechanics of hypothesis 2 described below (that is, they do not have a full comprehension of the power of capillary pressure). The problem with hypothesis 1 is a misunderstanding of basic chemical kinetics. Any basin not currently experiencing progressive burial (or increased heat flow) equivalent at least to the maximum burial depth and heat flow reached during its geologic history (i.e., every cratonic basin in North America) cannot be presently generating hydrocarbons (D. M. Jarvie, 2003, personal communication). The reason is that as organic material (i.e., kerogen) is subjected to increased heat, complex molecules are broken down into smaller molecules. For any given precursor organic matter, the chemical bonds that hold the complex molecules together will break at a given temperature. As burial depth increases and, hence, the temperature rises, progressively simpler molecules will be generated by the breakdown (i.e., cracking) of more complex precursor molecules. Once a basin stops subsiding (or there is no increase in heat flow), this cracking of the more complex molecules ceases. As a basin subsides, the temperature (and, hence, the activation energy) experienced by the organic matter in the source rocks increases. Chemical bonds that are broken at, say, 200°F (93°C), will be broken during burial as the source rock passes down through the 200°F (93°C) thermocline. During uplift, the source rock may yet again be exposed to 200°F (93°C), but the bonds that would be broken at 200°F (93°C) have already been broken during burial; thus, no additional hydrocarbons can be generated. For the Barnett to generate more hydrocarbons, it will have to be exposed to a higher temperature (i.e., to a higher activation energy) than it experienced in the past.

Hypothesis 2

The present-day overpressure (approximately 0.52 psi/ft [11.76 kPa/m]) is actually preserved from a normal pressure gradient (or slightly overpressured gradient formed by the generation of hydrocarbons at the time of maximum heat flow) established in the geologic past. The extremely low permeability (more precisely, the extremely high capillary pressure) of the Barnett permits this. Vitrinite reflectance profiles and basin modeling (Pollastro et al., 2007) from the Fort Worth Basin indicate that several thousand feet of upper Paleozoic and Mesozoic sediments have been eroded since the time of maximum burial in the Permian. The current average depth of the Barnett in Newark East field is about 7500 ft (2300 m); hence, the average reservoir pressure in the Barnett is

\[ 0.52 \text{ psi/ft} \times 7500 \text{ ft} = 3900 \text{ psi (27,048 kPa)} \] (1)

If we assume a normal hydrostatic pressure gradient of 0.44 psi/ft (9.95 kPa/m) (which is the pore-pressure gradient of the Ellenburger in the basin), we only need to have eroded

\[ 3900 \text{ psi/0.44 psi/ft} - 7500 \text{ ft} = 1364 \text{ ft (415 m)} \] (2)

of overburden to account for the 0.52 psi/ft (11.76 kPa/m) seen in the Barnett. We know that the Barnett is the source of nearly all the hydrocarbons now found in the Fort Worth Basin (Jarvie et al., 2001, 2003; Pollastro, 2003; Pollastro et al., 2004; Montgomery et al., 2005), so the Barnett must have been leaking throughout the time of hydrocarbon generation and subsequent uplift. More so, Barnett-sourced gas is presently migrating to the surface in the basin; however, the Barnett is tight enough (Figure 1) to absorb the 600 psi (4136 kPa) differential (this value is taken at the average depth of 7500 ft [2300 m] cited above) across the formation boundaries above and below the shale itself and retard the complete depressurization of itself.

Several formal presentations (primarily by personnel from Devon) report that the Barnett Shale outside the core producing areas of Wise, Denton, and northern Tarrant counties (i.e., Johnson County) is not overpressured. I do not believe this is the case based on three
lines of reasoning. First, the geologic history and processes that caused overpressure in the Barnett within the core area are similar to those outside the core area (Johnson County). The Barnett burial history in Johnson County would thus have to be much different than in the core area for the Barnett not to be overpressured, but stratigraphic and vitrinite reflectance profiles constructed for both areas show similar geologic histories. Second, I suspect that those who state that the Barnett in Johnson County is not overpressured are unfamiliar with how the Barnett was determined to be overpressured in the core area in the first place. When Mitchell Energy initiated the development of the Barnett in the Newark East core area, the company performed numerous prefracture-treatment, 10-day pressure dip-in tests (following limited casing perforation and a very limited breakdown of those perforations, the well is shut in for 10 days; a pressure bomb is then run in the hole to measure the bottom-hole pressure) to locate areas of pressure depletion caused by faulting. The dip-in tests actually measure formation deliverability better than they measure formation pore pressure. Of the more than 30 tests performed, only a few showed gradients of 0.52 psi/ft (11.76 kPa/m). The remaining tests with lower gradients did not indicate lower reservoir pressure in the area of the tested well, only that there was lower permeability. Because the maximum recorded pressure gradient was 0.52 psi/ft (11.76 kPa/m), this value for the Barnett was reported by various Mitchell workers in the literature (Lancaster et al., 1993). In Johnson County, only a few pressure buildup tests prior to fracture treatment were performed to definitively characterize the reservoir pressure gradient; however, I suspect that reservoir pressures are similar to Newark East at 0.52 psi/ft (11.76 kPa/m). Finally, recent excellent production results from horizontal wells drilled in Johnson County (some of the best producing wells to date in the play are in Johnson County) indicates that the Barnett is similarly overpressured as in the Newark East core area.

ORIGIN OF LIMESTONE BEDS AND CALCAREOUS NODULES WITHIN THE BARNETT

There has been some discrepancy among Barnett workers regarding the nature of numerous limestone beds, most of them less than 3 ft (0.91 m) thick, within the Barnett, including the Forestburg limestone unit. Some believe (for example, Johnson, 2003) that these limestone units resulted from marine regression and the resultant formation of carbonate shoals, similar to those described as Bahamian banks and shoals. Limestone beds within the Barnett can be correlated for miles across the basin. The origin of these limestone beds is of economic interest because, although they are rarely productive, any increased carbonate content lowers the volume of shale gas in place. Thus, any depositional model that can predict location, distribution, and thickness of these limestone beds would be helpful in the exploration and exploitation of the Barnett. The shoaling model is, however, unreasonable. Unfortunately, most Barnett workers have apparently not had access to Barnett core and have, therefore, based their interpretation solely on electrical-image logs.
Evidence from visual core analysis indicates that these limestone beds within the Barnett originated from submarine debris flows with a possible provenance in southern Oklahoma. An additional source of this carbonate debris has been proposed by Hall (2003) in the then nascent Muenster arch, but this seems unlikely because the Muenster arch does not appear to have had any prominent relief until after the Barnett was deposited.

1. Core examination clearly shows that the carbonate material was deposited in beds that contain many of the defining characteristics of a debris flow: scoured basal contact containing rip-up clasts of Barnett Shale in a chaotic mixture with fossil debris, fining-upward sequence exhibiting characteristics of continuous deposition within a single event, and upward gradation into black-shale deposition (Figures 2, 3).

2. Isolith mapping of the Forestburg limestone within the Barnett clearly indicates that the greatest thickness of limestone within the Barnett is where the Barnett was (and currently is) structurally deepest (Figure 4). It seems unlikely that if the limestones truly represent shoaling sequences, they would be concentrated in the deepest part of the basin.

Limestone nodules in the Barnett are occasionally observed on electrical-image well logs. I believe that not all carbonate nodules in the Barnett are of diagenetic origin, but some may be the result of soft-sediment deformation (the formation of recumbent folds within carbonate layers caused by sediment instability). Similar structures have been described in the Green River Formation oil shales by Grabowski and Pevear (1985). Examination of Barnett core bolsters this contention. However, recent work by P. K. Papazis (2005, personal communication) indicates that some carbonate nodules are indeed diagenetic in origin.

**WHY SOME PARTS OF THE CORE AREA OF THE FIELD ARE BETTER THAN OTHERS**

Within the main producing area of the Newark East field (called the “core” producing areas by Barnett workers), there are at least two well-defined areas where the Barnett is most productive. One is in southeast Wise County (centered on the Pearl Cox lease), and the other is in northern Tarrant County (centered on the Bonds Ranch lease). Why these two areas are more productive, no matter the completion technique, is not certain, but it must be for one (or a combination) of the following reasons: (1) these areas have a better gas-transmission mechanism, or (2) more gas in place exists (i.e., higher gas concentration). Understanding the geologic reasons why these two areas have higher productivity would aid in the exploration and exploitation efforts of the play, but currently, the reason(s) are unknown.

**Figure 2.** Barnett core showing a poorly sorted debris-flow deposit. Rip-up clasts and shell debris are present within the sample. Note the stress-relief fractures in the sample. Core is 3 in. (7.6 cm) across.
No published study has systematically examined the permeability and diffusivity of the Barnett, and to my knowledge, no such study exists in industry. Wireline logs do not directly determine permeability and diffusivity in the Barnett; thus, we can only use measurements from core. Further, only Devon Energy has sufficient core material across the field to conduct a systematic study.

**Gas in Place**

In the Barnett, gas is stored in pore spaces and adsorbed onto organic matter (clay does not appear to adsorb gas in the Barnett based on limited adsorption experiments run on only the clay fraction extracted from the Barnett). In the Barnett core area where production is greatest, there may be a higher concentration of organic matter in the Barnett resulting in higher gas-in-place volumes. Only estimates of the concentration of organic matter present in the Barnett can be derived from standard wireline logs, and it is not apparent from these wire-line logs that, in fact, there is an increased concentration of organic matter in these two areas. Again, only the analysis of core samples can best provide the answer to these questions. In addition, differences in shale diagenesis in one area compared to another would directly affect the petrophysical properties of the shale and may explain local variations in gas production.

**Figure 3.** Barnett core showing the abrupt bottom boundary of a carbonate-rich debris-flow deposit. The deposit grades into the typical organic-rich shale facies about 2 ft (0.6 m) above the base, indicating that it was deposited in a single event. Core is 3 in. (7.6 cm) across.

**Gas Transmission**

The many foreland basins of the Ouachita system (with the possible exception of sections of the Permian Basin of west Texas) have experienced abnormally high thermal gradients in the geologic past (Bethke and Marshak, 1990). These basins (namely, the Arkoma, Fort Worth, certain subbasins of the Permian Basin, and, to some extent, the Black Warrior) have historically produced dry gas in the regions adjacent to the Ouachita thrusting. In the Fort Worth Basin, it has been shown that the proximity to the Ouachita front and not the depth of burial is the major controlling factor in thermal maturity (Bowker, 2003; Pollastro et al., 2004). Hot brine squeezed out in front of the advancing Ouachita system and moving forward through the Ellenburger (Bethke and Marshak, 1990; Kupecz and Land, 1991) appears to be the source of the increased heat flow.

Because the movement of hot fluid through the Ellenburger appears to have controlled the thermal maturity of the Barnett, structural features (predominantly faults) are a factor in determining the Barnett’s thermal
maturity because (1) hot water probably flowed up faults into the overlying Barnett, increasing the thermal maturity in some fault blocks more than in others; and (2) faults could have acted as baffles and diverted hot Ellenberger water around certain fault blocks. The calorific content of produced Barnett gas varies systematically within a major fault block, with the lower British thermal unit content closest to the Ouachita front. However, the British thermal unit content will jump by several tens of British thermal units across a major fault, e.g., the Mineral Wells fault that cuts across the northern core area of Newark East field. The calorific value of gas produced from the Barnett (or even shallower reservoirs) can be used to map major fault trends. A systematic examination of Ellenberger core across the Fort Worth Basin may illuminate the thermal history of the basin.

THE BARNETT AS AN EXPLORATION MODEL

Once one acquires a basic understanding of what makes the Barnett so productive, exploring for similar accumulations is straightforward. The explorationist should not look for fractured, gas-saturated shales, but instead, for gas-saturated shales that can be fractured. The details are, of course, more complex, but they are fundamentally associated with two primary related variables: (1) shale composition (mineralogy) and (2) resulting gas-in-place volumes.

Gas in Place

To have an economic shale-gas play, there must be a sufficient amount of gas in place within the shale. Thus, the shale must also be a hydrocarbon source rock that generated large volumes of either thermal or biogenic gas. To have generated such large volumes of gas, the shale needs to have been rich in organic matter, relatively thick, and have been exposed to a source of heat in excess of usual global geothermal gradients. Gas is stored in the Barnett via two mechanisms. Gas is stored in the matrix porosity and/or adsorbed onto organic matter (Bowker, 2003). Thus, the shale in question has to have sufficient organic matter and/or enough matrix porosity to store quantities of gas sufficient to make the shale viable as an exploration target.
Concentration of Organic Matter
The organic carbon concentration in the Barnett ranges from less than 0.5 to more than 6 wt.%, with an average of about 4.5 wt.% (Bowker, 2003), and the amount of adsorbed gas is proportional to the amount of organic carbon in the Barnett (Mavor, 2003). Intervals with higher concentrations of organic carbon commonly exhibit higher gas in place and, generally, the highest matrix porosity and the lowest clay content. All three of these factors probably act to make higher TOC zones more prospective. The minimum TOC required for a prospective shale to become a viable exploration target is not known, but appears to be about 2.5–3 wt.%.

Thickness
Geoscientists do not know how thin the Barnett can be and still produce economic quantities of gas. In the Michigan Basin, the productive zone within the Antrim is about 30 ft (10 m) thick in the productive fairway. For the Barnett, it appears that 100 ft (30 m) will prove to be thick enough for commercial production (although in areas where the Barnett is that thin, it is also thermally less mature, and it is relatively shallow), but 50 ft (15 m) may be too thin.

Thermal Maturation
The prospective shale must have been well within the thermal gas-generation window to be a potential exploration target for shale-gas production. Jarvie et al. (2007) reviews the various techniques and analyses that can be used to assess thermal maturation. To produce economic rates of gas, the Barnett must be well within the gas window.

Matrix Porosity
Some geoscientists think that approximately half the gas at Newark East field is stored in matrix porosity (Bowker, 2003). However, there is a growing belief among some Barnett workers, and based on apparently proprietary data, that substantially more than 50% of the gas in place is stored in matrix porosity. Novel techniques, first developed under contract of the Gas Research Institute, must be employed to accurately measure porosity in rocks as impermeable as the Barnett; conventional laboratory measurements are not adequate. Few laboratories are capable of determining these measurements accurately. Water saturation is even more difficult to measure in shales. Of course, both porosity and water saturation must be known to adequately assess the viability of a new exploration play. The organic-rich parts of the Barnett average approximately 5.5% porosity and 25% water saturation (Bowker, 2003).

Mineralogy
Most shales contain a high concentration of clay minerals; conversely, the Barnett and many of the other productive shales do not. In prospecting for Barnett-type shales, the explorationist must look for rock that can be fractured, that is, shale with a low enough concentration (generally less than 50%) of clay minerals to allow it to be successfully fracture stimulated. These types of shales were mostly deposited in restricted areas and only during specific geologic time intervals; e.g., the Devonian–Mississippian Antrim Shale of Michigan or the subject Barnett Shale.

SHORT NOTE ON THE HISTORY OF PRODUCTION FROM THE BARNETT IN NORTH TEXAS
Figure 5 shows the production history of Newark East field; it is unique in the oil and gas industry. The most apparent feature is the large increase in production that began in 1999. What happened in that year? Why did it take 17 yr for production to take off (and why did Mitchell Energy stay with the play so long with so little to show for it productionwise)? Another unusual aspect of the field’s production history is that the combined production from wells that were completed before 1999 actually have higher total yearly production in 2003 than they did in 1998. I cannot explain why Mitchell stuck with the Barnett for so long without seeing any real success; I trust that history will be chronicled soon by those that were at Mitchell during that period. Two reasons exist for the large production increase in 1999: the discovery that the true gas in place is nearly four times what was previously believed and the successful application of water fractures (basically a combination of water, friction reducer, bactericide, scale inhibitor, and low sand concentration) in the play that decreased the total well costs substantially. These two discoveries led to the restimulation of existing wells (hence, the increase in the production from pre-1999 wells mentioned above), downspacing, successful completions in the previously unproductive upper Barnett,
Figure 5. Newark East (Barnett Shale) field yearly production curve (data through September 2005). Production is color coded based on the year of completion. Note the steep increase in gas production starting in 1999. Data are from the Texas Railroad Commission (2005).
and a huge overall improvement in the economics of the play. (See Bowker, 2003, for a detailed account of how the gas content of the Barnett was determined and Walker et al., 1998, for a review of water fractures in the Barnett of north Texas.)

The production curve (Figure 5) has steadily increased thanks to improved understanding of the Barnett and, most significantly, the widespread deployment of horizontal drilling techniques in the play starting in 2002.

SUMMARY

Misunderstanding and confusion continue regarding the prolific Barnett Shale reservoir of north Texas. This article is an attempt to clarify some of these issues, including the insignificance of open natural fractures in the productivity of the Barnett, the origin of limestone beds found in the Barnett, the source of the relatively high heat flow in the basin, and the origin of overpressuring in the Barnett. Many important aspects of the Barnett continue to be a mystery; no one completely understands the prolific nature of gas production from the Barnett at the present time. The Barnett play continues to grow at an astonishing rate, and it is serving as a model for similar gas-shale plays now being developed.

REFERENCES CITED


