Abstract

Shale gas currently provides 20% of domestic supply, is targeted by half of the gas-directed drilling rigs, and represents the large majority of domestic resources. However, modern shale plays, their development strategies and their engineering analysis are young by comparison to those of conventional reservoirs. Uncertainty in shale gas reserves has significant implications at both the micro and macro levels.

Conventional reservoir engineering tools must be viewed as potentially inadequate (or even inappropriate) for the evaluation of shale gas performance primarily because of the extremely low aggregate permeability of these systems, but also because of other unique aspects of the systems. Reservoir modeling (simulation) has an important role as an assessment and prediction tool; however, the character of the reservoir (induced and enhanced natural fractures) must be considered, as well as the geological and fluid characteristics. Rate-transient analysis (modern decline analysis) techniques are also more rigorous and have been expanded and adapted to fit the uniqueness of shale gas production. Application of each method for shale gas is discussed, including methods and limitations. These two techniques more closely represent the physics of shale gas production, but their implementation is often prohibitive.

By way of necessity, much engineering evaluation is performed using Arps decline curve analysis. This technique is argued by some to be inappropriate due to a lack of theoretical support and demonstrated tendency to over-estimate reserves in tight gas systems. Given the limitations, practical methods exist to reduce error associated with its use. A newer decline method, power-law exponential, is also investigated.

Introduction

Gas shales currently supply 20% of gas production in the United States, and the majority of gas resources in the United States. It has been the target of major capital expenses in recent years and probably represents the cause of the current gas supply glut. Expansion of gas shale plays to other parts of the world is gaining momentum.

Despite the massive capital investments made in recent years, the science of shale gas analysis and forecasting is relatively young. Horizontal wells with large, multi-stage fracture treatments became the standard protocol for gas shales in 2005, a mere six years ago, and only a few hundred wells were drilled in that year. Though around twenty thousand horizontal shale wells have been drilled to date, the longest actual production history available is about six years. To further complicate matters, the usually frenetic and sometimes frothy nature of shale development creates an urgent need for accurate predictions of recovery very early in the life of a play.

Unfortunately, geologic and reservoir engineering principles for analysis of gas shales have lagged the science of hydraulic fracturing. In the early days of the Barnett Shale expansion, it was widely believed that regional variations in the quality of the formation was relatively minor. Production mechanisms were poorly understood, as was petrophysical analysis. It was argued, and is to certain extent still, that completion technology was the primary determinant of production and thus economic success.
At this point, the industry’s ability to interpret logs, analyze core and understand (at least qualitatively) the geologic controls on production has vastly increased and they have proved to be more important than previously acknowledged. Those geologic factors have proven to be more numerous and more complexly inter-related than for conventional reservoirs.

From the beginning of shale gas production, even before the industry understood the rock and how to fracture it, forward-looking reserve determination has been required to provide guidance on economics of development, and the engineers responsible have faced the task with limited experience or literature from which to draw. This paper aims to provide a practical guide to the application of appropriate engineering techniques for the determination of reserves in shale gas plays.

Overview of Engineering Methods

Depending upon how one groups the methods, there are six basic engineering techniques for the determination of reserves in general: volumetrics, analogy, production performance, material balance, simulation and, most recently, rate-transient analysis. Each method has its own predicates and limitations. In the case of shale gas, they also have their own idiosyncrasies for accurate application.

Material balance is not a suitable technique because the ultra-low matrix permeability makes obtaining average reservoir pressure impractical. As for volumetrics, improvements in core and petrophysical analyses have led to reasonable estimates of gas in place. However, the recovery factor to be applied to an in-place figure is imprecise at best. While the storage and permeability of the matrix may be reasonably well-constrained where cored, matrix flow properties can vary more widely than it is practical to measure, and ultimate recovery also depends heavily on how the rock responds to hydraulic fracturing. The effectiveness of the stimulation can be affected by, for instance, mineralogy, mechanical properties, natural fracturing, hardness, faulting, layering, and local and regional geomechanical stresses, not to mention the many aspects of the design of the fracture treatment itself. The number and inter-relation of these and other parameters, creates more variables than can (currently) be discriminated a priori for the prediction of a reasonable recovery factor. Moreover, there remains significant uncertainty in the ultimate recovery of the fields to which analogy might be made; these estimates of recovery factor may be in error. The least productive of tested shale plays has recovered on the order of 1-2% of gas in place while some have argued that localized recoveries in the Barnett Shale will reach 30% or greater, but these may be significantly in error.

With greater experience in a wider array of shales, it may become possible to narrow the range of reasonable expectations for recovery factor to bound reserve estimates. On the other hand, since recoveries are so low, a difference of even 5% in the expected recovery factor could translate to a 50 to 200% difference in by-well ultimate recovery.

Simulation and rate-transient analysis better represent the actual physics involved in reservoir dynamics, but early applications faced steep problems. In the case of rate-transient analysis, formulations were not initially available to handle the physical geometry of the completions. Simulation was more flexible, but there was significant uncertainty as to the nature of the resulting completion, production mechanisms and how to model these.

The many difficulties caused engineers to rely heavily on the simplest, most accessible tool: production decline analysis. Often, very large asset purchases or even entire plays have been reduced to a single type curve based on production performance. This fact concentrates and thus amplifies the potential error. Without the benefit of good analogs or sufficient guidance from first principles, it is possible, even likely, that production analysis results in a blithely optimistic view of ultimate recovery.

Fortunately, concentrated effort by many engineers and academics has significantly advanced the understanding of and analysis tools for shale gas. These last three methods – simulation, rate-transient analysis, and decline analysis – all have now demonstrated usefulness in gas shales, but they must be applied in a manner consistent with the uniquenesses of shale reservoirs.

Numerical Simulation in Unconventional Reservoirs

Numerical models have evolved in complexity, stability and ease of use to the point where they are widely available. Almost all significant oil and gas reservoirs worldwide are managed through the use of detailed reservoir models. In contrast to full field models, shale gas modeling is usually done at the well level. Numerical models capable of modeling the most important features of tight gas and gas shales are also available now and are undergoing further development to include better representations of the basic physics controlling gas flow as the industry learns more.

[1] Also known as production analysis, modern decline analysis or time-pressure-rate analysis.
Matching historical performance and predicting future recovery is data and manpower intensive and often viewed as impractical for common business purposes. However, with fast, stable models and ever increasing machine speed, our experience has been that numerical simulation is a valuable tool for A&D purposes, field development, surveillance and recovery estimates. As with any sufficiently advanced technique, there are proper and improper uses of simulation. Simulation is not a substitute for sound reservoir engineering and should not be used as a “black box with many knobs,” becoming the world’s most expensive curve-fitting tool. The basic principles of thermodynamics and physics controlling fluid flow in porous media are bedrock in today’s commercial models. Most commercial models also include dual porosity dual permeability behavior and are suitable for use on shale gas reservoirs.

A threshold question is “Should numerical simulation be used to forecast production from shale gas wells?” As a sense check of the viability of using simulation in this role, we compared a prior, 2001, history match and forecast of 15 Barnett wells for a proposed transaction. At the time the work was done the only observed data available was three to twelve months of monthly flow rates, far from an ideal data set. Since nine years have passed since the original work we updated the monthly production data to compare to the original forecasts. **Table 1** lists the 15 wells and the correlation coefficient between actual and simulated rates. Four of the 15 wells had a correlation coefficient lower than 0.7 and combining all the wells results in a correlation coefficient of 0.737.

**Table 1 — Correlation Coefficient for 15 Barnett Wells**

<table>
<thead>
<tr>
<th>Well</th>
<th>R Squared</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pavillard 8</td>
<td>0.894</td>
</tr>
<tr>
<td>Briscoe 12</td>
<td>0.960</td>
</tr>
<tr>
<td>Briscoe 9</td>
<td>0.936</td>
</tr>
<tr>
<td>Briscoe 5</td>
<td>0.925</td>
</tr>
<tr>
<td>Briscoe 4</td>
<td>0.403</td>
</tr>
<tr>
<td>Briscoe 3</td>
<td>0.924</td>
</tr>
<tr>
<td>Briscoe 2</td>
<td>0.868</td>
</tr>
<tr>
<td>Briscoe 1</td>
<td>0.916</td>
</tr>
<tr>
<td>Timlin 1</td>
<td>0.502</td>
</tr>
<tr>
<td>Foreman 3</td>
<td>0.630</td>
</tr>
<tr>
<td>Foreman 2</td>
<td>0.753</td>
</tr>
<tr>
<td>Dodd A1</td>
<td>0.865</td>
</tr>
<tr>
<td>Bonds 505</td>
<td>0.799</td>
</tr>
<tr>
<td>Bonds A 105</td>
<td>0.542</td>
</tr>
<tr>
<td>Bonds A 103</td>
<td>0.839</td>
</tr>
</tbody>
</table>

The goal in history matching is to develop an adequate proxy of fluid flow and recovery mechanisms sufficient to make reasonable forecasts. Proper history matching provides valuable insights such as extent and complexity of the induced fracture system, estimates of *in situ* rock properties and a calibrated well and reservoir description for forecasting production. Improper history matching often results in well and reservoir parameters at or beyond the limit of reasonableness, resulting more often than not in an optimistic forecast.

For the purposes of this paper, we only consider gas recovery and have chosen field examples not strongly influenced by the existence or development of a hydrocarbon liquid phase. We chose wells from the Haynesville and Barnett fields that had a usual type of data set. Our purpose is to demonstrate simulation techniques and not to cover the full range of results encountered by horizontal wells. Modeling gas recovery in shale gas reservoirs has additional layers of complexity compared to conventional reservoirs. Recovery is affected by the ultra-low matrix permeability, matrix porosity, completion efficiency of horizontal wells, complex hydraulically induced fracture systems, stimulated rock volume, dual porosity dual permeability flow systems, desorption, stress dependent fracture permeability as well as phase behavior issues.

The usual data set available for history matching includes, at best, daily gas production rate, flowing well head casing or tubing pressures, choke sizes, gas analysis, wellbore schematic with completion information, reservoir temperature, initial pressure and a geologic description including gross and net thickness and porosity. The approach used in history matching varies with the quality and quantity of available data. If flowing casing and tubing pressures are available, they should be converted to flowing bottomhole pressures. Simulation proceeds by specifying either flow rate or bottomhole pressure and matching the other parameter. History matching variables normally include reservoir properties of matrix porosity and permeability, fracture spacing and complexity, fracture properties of porosity and permeability (depending on the model used this may be expressed as fracture conductivity or a fracture-matrix transfer term), stimulated rock volume and stress dependent permeability for the fracture system. Other common variables are effective lateral length, net thickness, and the maximum drained area.

History matching a well with one year of daily data, production and flowing pressure involves investigation of all of the above parameters. When matching flowing pressures or production rates, each of the variables affects the simulated values in a different way. Primary variables should be estimated first, then secondary variables. Our simulations of the major gas shale plays, Barnett, Fayetteville, Haynesville, Marcellus and Eagle Ford, has revealed that there is an interplay between variables and their effect on observed well behavior. **Fig. 1** distinguishes primary and secondary variables over different periods of production denoted as early time (ET), middle time (MT) and late time (LT). Area 1 in the figure is the stimulated rock volume.
During the early time region, usually lasting one to three months, the primary controlling variables are fracture permeability, fracture spacing and effective lateral length. In the middle time region the magnitude of the response is dominated by fracture permeability and the width of the stimulated area with the duration of the middle time region controlled by the volume of the stimulated area. Secondary variables during the middle time region are matrix porosity and net thickness. Important variables in the late time region are matrix permeability and porosity and fracture spacing of any natural fractures in the non-stimulated area. Some variables, for example fracture permeability have an effect across all time regions. An increase in fracture permeability also increases the magnitude of the simulated response in the late time region. An increase in matrix porosity adds little to the response during the early time region but has a larger response in the middle and late time regions.

In some cases we have found that better history matches are obtained if the stimulated rock volume, Area 1, is subdivided into three regions, wellbore, near wellbore and remaining area with higher fracture permeability in the wellbore region and lower fracture permeability in each succeeding region. In deep high pressure systems such as the Haynesville, the effect of a graduated permeability configuration can be represented as, or in conjunction with, stress-sensitive permeability simulated as a transmissibility multiplier.

**Parametric Studies**

Starting place values for parameters are chosen from core data and petrophysical evaluations if available. Additional parameters are chosen from a series of parametric studies covering the ranges of flow rates and pressures seen in the actual data. Tables 2 and 3 list parametric variable values for simulated wells in the Haynesville and Barnett fields. For both studies base case values were chosen then individual variables were varied to a high and low estimate yielding Figs. 2 and 3, composite plots of simulated rates. The discussion of Arps is covered in the decline curve analysis section.

### Table 2—Parametric Values and Comparison of Simulation and Arps EUR (Barnett)

<table>
<thead>
<tr>
<th>Run Name</th>
<th>Property Changed</th>
<th>New Value</th>
<th>EUR Bcf</th>
<th>Initial Rate MMcf/D</th>
<th>Initial Decline, %</th>
<th>B-factor</th>
<th>Final Decline, %</th>
<th>EUR Bcf</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barn1</td>
<td>None (base case)</td>
<td>N/A</td>
<td>2.0</td>
<td>4.9</td>
<td>91.7</td>
<td>0.71</td>
<td>0</td>
<td>1.8</td>
<td>poor match</td>
</tr>
<tr>
<td>Barn2</td>
<td>Fracture Perm</td>
<td>0.5</td>
<td>2.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Barn3</td>
<td>Fracture Perm</td>
<td>0.005</td>
<td>1.9</td>
<td>1.5</td>
<td>20.4</td>
<td>0.95</td>
<td>0</td>
<td>1.85</td>
<td></td>
</tr>
<tr>
<td>Barn4</td>
<td>SRV Width</td>
<td>350</td>
<td>2.8</td>
<td>4.7</td>
<td>78.2</td>
<td>0.65</td>
<td>0</td>
<td>2.6</td>
<td></td>
</tr>
<tr>
<td>Barn5</td>
<td>SRV Width</td>
<td>150</td>
<td>1.5</td>
<td>4.7</td>
<td>97.8</td>
<td>0.80</td>
<td>0</td>
<td>1.4</td>
<td></td>
</tr>
<tr>
<td>Barn6</td>
<td>Frac Spacing X&amp;Y</td>
<td>3</td>
<td>2.0</td>
<td>4.6</td>
<td>91</td>
<td>0.70</td>
<td>0</td>
<td>1.8</td>
<td></td>
</tr>
<tr>
<td>Barn7</td>
<td>Frac Spacing X&amp;Y</td>
<td>25</td>
<td>2.1</td>
<td>4.1</td>
<td>85.8</td>
<td>0.69</td>
<td>0</td>
<td>1.8</td>
<td></td>
</tr>
<tr>
<td>Barn8</td>
<td>Matrix Perm</td>
<td>0.000250</td>
<td>3.0</td>
<td>4.9</td>
<td>92.3</td>
<td>0.91</td>
<td>0</td>
<td>2.8</td>
<td></td>
</tr>
<tr>
<td>Barn9</td>
<td>Matrix Perm</td>
<td>0.000001</td>
<td>1.3</td>
<td>2.8</td>
<td>70</td>
<td>0.41</td>
<td>0</td>
<td>1.3</td>
<td></td>
</tr>
<tr>
<td>Barn10</td>
<td>Gas Filled Por</td>
<td>0.07</td>
<td>3.0</td>
<td>5.2</td>
<td>88.1</td>
<td>0.77</td>
<td>0</td>
<td>2.6</td>
<td></td>
</tr>
<tr>
<td>Barn11</td>
<td>Gas Filled Por</td>
<td>0.03</td>
<td>1.3</td>
<td>3.9</td>
<td>95.3</td>
<td>0.67</td>
<td>0</td>
<td>1.1</td>
<td></td>
</tr>
</tbody>
</table>
pressures displayed as a function of cumulative gas produced instead of time. Several wells merit further discussion.

The first step in the history matching consisted of making systematic changes of primary variables for the different flow regions as shown in Fig. 1. Once primary variables were adequately identified, a semi-automatic history matching procedure, namely conjugant gradient, was used. Reservoir mechanisms are often more apparent with well rates and pressures displayed as a function of cumulative gas produced instead of time. Several wells merit further discussion.

<table>
<thead>
<tr>
<th>Run Name</th>
<th>Property Changed</th>
<th>New Value</th>
<th>EUR Bc</th>
<th>Initial Rate MMcfd</th>
<th>Initial Decline, %</th>
<th>B-factor</th>
<th>Final Decline, %</th>
<th>EUR Bc</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Haynes1</td>
<td>None (base case)</td>
<td>N/A</td>
<td>12.7</td>
<td>10.0</td>
<td>94.2</td>
<td>1.53</td>
<td>3.5</td>
<td>12.7</td>
<td>2 mo at IR</td>
</tr>
<tr>
<td>Haynes2</td>
<td>Fracture Perm</td>
<td>3</td>
<td>16.0</td>
<td>10.0</td>
<td>100.0</td>
<td>1.70</td>
<td>2.0</td>
<td>15.9</td>
<td>poor match, 28 mo at IR</td>
</tr>
<tr>
<td>Haynes3</td>
<td>Fracture Perm</td>
<td>0.005</td>
<td>11.0</td>
<td>9.0</td>
<td>99.1</td>
<td>1.77</td>
<td>3.0</td>
<td>11.1</td>
<td>2 mo at IR</td>
</tr>
<tr>
<td>Haynes4</td>
<td>SRV Width</td>
<td>350</td>
<td>14.7</td>
<td>10.0</td>
<td>82.3</td>
<td>1.35</td>
<td>4.0</td>
<td>14.7</td>
<td>1 mo at IR</td>
</tr>
<tr>
<td>Haynes5</td>
<td>SRV Width</td>
<td>150</td>
<td>11.1</td>
<td>10.0</td>
<td>98.0</td>
<td>1.53</td>
<td>2.0</td>
<td>11.2</td>
<td>1 mo at IR</td>
</tr>
<tr>
<td>Haynes6</td>
<td>Frac Spacing X&amp;Y</td>
<td>5</td>
<td>12.7</td>
<td>10.0</td>
<td>94.0</td>
<td>1.47</td>
<td>2.5</td>
<td>12.7</td>
<td>2 mo at IR</td>
</tr>
<tr>
<td>Haynes7</td>
<td>Frac Spacing X&amp;Y</td>
<td>200</td>
<td>12.1</td>
<td>3.4</td>
<td>28.0</td>
<td>1.17</td>
<td>2.5</td>
<td>12.1</td>
<td>2 mo at IR</td>
</tr>
<tr>
<td>Haynes8</td>
<td>Matrix Perm</td>
<td>0.00030</td>
<td>14.9</td>
<td>10.0</td>
<td>90.0</td>
<td>1.57</td>
<td>4.0</td>
<td>14.9</td>
<td>2 mo at IR</td>
</tr>
<tr>
<td>Haynes9</td>
<td>Matrix Perm</td>
<td>0.00004</td>
<td>10.9</td>
<td>10.0</td>
<td>93.0</td>
<td>1.31</td>
<td>2.5</td>
<td>11</td>
<td>2 mo at IR</td>
</tr>
<tr>
<td>Haynes10</td>
<td>Gas Filled Por</td>
<td>0.076</td>
<td>14.7</td>
<td>10.0</td>
<td>90.0</td>
<td>1.49</td>
<td>3.0</td>
<td>14.6</td>
<td>3 mo at IR</td>
</tr>
<tr>
<td>Haynes11</td>
<td>Gas Filled Por</td>
<td>0.030</td>
<td>7.8</td>
<td>10.0</td>
<td>99.3</td>
<td>1.40</td>
<td>3.5</td>
<td>7.8</td>
<td></td>
</tr>
</tbody>
</table>

**Haynesville Simulations**

Eight wells completed in the Haynesville field were simulated. Common among all the wells was the use of stress sensitive matrix and fracture permeability. Table 4 shows transmissibility multipliers applied to the matrix and fractures in our Haynesville simulations. Stress is the change in reservoir pressure from initial conditions on a cell by cell basis. Table 5 shows well and reservoir properties after history matching. Initial pressure varied with depth with all wells at approximately 11,100 psia. As has been our prior practice when presenting simulation results for shale gas reservoirs, complete data sets are available for interested parties. The hope is to generate appropriate discussion and forward movement toward understanding these complex systems.

### Table 4—Stress-dependent Permeability Modifiers (Haynesville)

<table>
<thead>
<tr>
<th>Stress, psi</th>
<th>Fracture</th>
<th>Matrix</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0.10</td>
<td>1.00</td>
</tr>
<tr>
<td>3,000</td>
<td>0.50</td>
<td>0.95</td>
</tr>
<tr>
<td>6,000</td>
<td>0.20</td>
<td>0.90</td>
</tr>
<tr>
<td>9,000</td>
<td>0.10</td>
<td>0.85</td>
</tr>
<tr>
<td>12,000</td>
<td>0.05</td>
<td>0.80</td>
</tr>
</tbody>
</table>

The first step in the history matching consisted of making systematic changes of primary variables for the different flow regions as shown in Fig. 1. Once primary variables were adequately identified, a semi-automatic history matching procedure, namely conjugant gradient, was used. Reservoir mechanisms are often more apparent with well rates and pressures displayed as a function of cumulative gas produced instead of time. Several wells merit further discussion.

### Table 5—Haynesville Best History Match Reservoir Properties by Well

<table>
<thead>
<tr>
<th>Reference</th>
<th>Lateral Length</th>
<th>Spacing X</th>
<th>Spacing Y</th>
<th>Perm at Well</th>
<th>Perm Near Well</th>
<th>Perm Remaining</th>
<th>Stimulated Rock Vol</th>
<th>Porosity Gas Filled</th>
<th>Perm</th>
<th>Total Rock Vol</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well 1</td>
<td>3,800</td>
<td>10</td>
<td>10</td>
<td>0.109</td>
<td>0.109</td>
<td>0.10900</td>
<td>6.474</td>
<td>6.8</td>
<td>0.00010</td>
<td>6.937</td>
</tr>
<tr>
<td>Well 2</td>
<td>4,400</td>
<td>10</td>
<td>10</td>
<td>0.087</td>
<td>0.087</td>
<td>0.08700</td>
<td>5.890</td>
<td>6.8</td>
<td>0.00066</td>
<td>11,459</td>
</tr>
<tr>
<td>Well 11</td>
<td>4,400</td>
<td>10</td>
<td>10</td>
<td>1.330</td>
<td>0.56600</td>
<td>4.819</td>
<td>11.2</td>
<td>5.0</td>
<td>0.00010</td>
<td>11,459</td>
</tr>
<tr>
<td>Well 23</td>
<td>3,300</td>
<td>14</td>
<td>14</td>
<td>0.266</td>
<td>0.56600</td>
<td>5.221</td>
<td>16.814</td>
<td>5.3</td>
<td>0.00010</td>
<td>14,529</td>
</tr>
<tr>
<td>Well 25-2</td>
<td>3,800</td>
<td>10</td>
<td>10</td>
<td>2.000</td>
<td>0.050</td>
<td>0.00125</td>
<td>15,962</td>
<td>4.6</td>
<td>0.00007</td>
<td>15,962</td>
</tr>
<tr>
<td>Well 26</td>
<td>2,800</td>
<td>5</td>
<td>200</td>
<td>0.099</td>
<td>0.099</td>
<td>0.09900</td>
<td>4,430</td>
<td>7.0</td>
<td>0.00030</td>
<td>7,292</td>
</tr>
<tr>
<td>Well 28-1</td>
<td>3,500</td>
<td>10</td>
<td>10</td>
<td>4.000</td>
<td>0.034</td>
<td>0.03400</td>
<td>6,111</td>
<td>5.3</td>
<td>0.00010</td>
<td>14,529</td>
</tr>
<tr>
<td>Well 28H-1</td>
<td>3,700</td>
<td>10</td>
<td>10</td>
<td>4.000</td>
<td>0.050</td>
<td>0.01600</td>
<td>16,814</td>
<td>3.5</td>
<td>0.00010</td>
<td>16,814</td>
</tr>
</tbody>
</table>
Discussion of History Matches

Fig. 4 shows the history match for Well 1. Solid points are observed rates and calculated bottomhole pressures while the solid black line is the simulated bottomhole pressure. Initial production was up casing prior to installation of tubing. The reported flowing tubing pressures were essentially constant for a period of time before declining. Consequently the flowing bottomhole pressure over the same period showed little change. No mixture of well and reservoir parameters was able to reproduce a sequence of declining rate and pressure, then declining rate and constant pressure followed again by declining rate and pressure. Reservoir variables were determined by matching the first portion of the bottomhole pressure when the well was flowing up the casing.

Figs. 5 through 8 show typical history matches. Additionally, Well 2 shown on Fig. 9 compares simulated performance with and without stress sensitive permeability. The no-stress case is a better history match up until the shut-in period of late January 2010. The stress case is a better match for the shut-in period and afterward. As in all the Haynesville simulations, stress sensitive permeability was used for history matching and forecasting.

Fig. 10 shows the history match for Well 28H-1. Of note is the period when well records indicated five offset wells were fracture treated. During that period both rate and pressure increased abruptly indicating that the drainage area of Well 28H-1 was breached by the offset fracturing. The resulting drainage area is a complex configuration making forecasting difficult unless all communicating wells are simulated as a group. This is an example where individual well simulation provides valuable insight for field development but may be of limited use for forecasting. Well 28-1, Fig. 11, also shows that the drainage area was breached by offset fracture treatments. In a similar manner for Well 25-2, Fig. 7, a better history match was obtained by including another well at the outer limit of the drainage area simulating loss of gas from the original drainage area. The second well was brought on after Well 25-2 had produced 1.6 Bcf and there was a sharp rise in the flowing bottomhole pressure.

Forecasts

As a result of history matching, three of the eight wells, Well 28H-1, Well 28-1 and Well 25-2, indicated interference and one well, Well 1, had limited data. These four wells have a higher uncertainty in their forecasts than the other five and should be treated accordingly. All wells were forecast by continuing the last flow rate until reaching a flowing bottomhole pressure of 1,500 psi at which time the wells were switched to constant flowing pressure and the simulation continued until a minimum flow rate was reached.

At the end of the actual data all wells had a calculated flowing bottomhole pressure of 3,000 psi or higher. Forecasting under these conditions results in a period of constant rate production until the flowing bottomhole pressure reaches 1,500 psi and the rates decline. The reality is that both rate and bottomhole pressure will continue to decline until reaching a minimum surface flowing pressure. Before a minimum constraint is reached flow rates are under the control of the operator through their choice of choke sizes and other surface operating conditions. To prevent forecasting at a constant rate another option is to schedule a number of short periods of declining constant pressure production in an attempt to approximate the prior rate decline. A third option is to model wellbore flow and schedule a series of increasing choke sizes to mimic historical practice. All of these methods impose the evaluators view on the forecast curve until a minimum constraint is reached.

Figs. 12 and 13 are composite plots of the eight wells with the first showing gas rates and the second cumulative gas produced. Forecasts and estimated ultimate recoveries, EUR’s, from simulation should not be put on the pedestal of “Absolute Truth”. The evaluators view of forecast methods and the fact that four of the eight wells have a higher uncertainty in their forecast emphasizes why simulation results must be tempered with sound engineering judgement.

Barnett Simulations

In the Barnett field we chose four wells on one lease with one operator and a typical data set consisting of daily rates and flowing pressures although some wells did not have a complete pressure history. Lack of complete pressure histories is less of a problem in the Barnett than in high pressure fields like the Haynesville because wells quickly reach surface constraints and decline under producing conditions adequately simulated by constant flowing bottomhole pressure. For this field flowing bottomhole pressure was specified with actual flow rates as the matching parameter. Table 6 lists well and reservoir variables determined from the history matches.
On this lease Well 1 and Well 2 were drilled in sequence and both begin producing at the same time. History matching was straight forward once primary variables were identified. One and a half years later Well 3 and Well 4 were drilled at in-fill locations. The first two wells have similar decline curve characteristics as do the last two wells but different from the first two. The last two wells came on at lower rates, declined faster and will have lower ultimate recoveries. Simulation of the two in-fill wells required including drainage from the initial wells. Without including the drainage effect only a rough match could be obtained by using low and unrealisitic matrix porosity. The history match plots are shown in Figs. 14 through 17 and forecasts of the four wells are shown in Figs. 18 and 19. As was the case in the Haynesville, simulation forecasts of the four Barnett wells should be balanced with sound engineering judgement.

Guidelines for Simulation of Shale Gas Reservoirs

This section contains lessons learned from 35 years of simulating reservoirs all over the world and 10 years of simulating shale gas reservoirs. These guidelines are focused on history matching and forecasting shale gas reservoirs, although many have general application to simulation.

1. **Proper choice of model** – Single porosity, single permeability models should not be used to simulate shale gas. A case can be made for using a dual porosity, single permeability model. However, dual porosity, dual permeability formulations are more appropriate. It is important to have a model that is fast and stable when using small cells and large contrasts in permeability. History matching by any method, manual, assisted or automatic, requires a large number of runs. Individual well simulations should be able to run with an elapsed clock time of no more than a couple of minutes. Matching daily rates or pressures is often not required. Keep run times down by averaging data. After an adequate match is obtained then make a final run honoring daily data. A four day average was used for the Haynesville and Barnett simulations.

2. **Work procedures** – Develop work procedures that minimize time spent in text editors, mouse clicking to change data, submitting runs, visualizing results and cataloguing what you did. Time spent on this issue is important. A history match is not when you run out of time, patience or money. Visual feedback on changes should be fast, while you are still concentrating on the physics and the simulation response. Automatic history matching methods should be used with caution. As discussed previously, variables overlap in influence and magnitude causing matching techniques to drive important variables to extremes. If you have to match 10 wells, then after finishing the last well always go back and re-do the first two or three to insure consistency in your approach. Do a comparison plot of all matches and forecasts looking for outliers. Investigate why these wells are outliers to make sure the simulation results are based on sound reasoning and not the result of an artificial constraint or assumption. Reviewers of simulation work always ask about the outliers.

3. **The matrix porosity issue** – If your data source for matrix porosity is from petrophysical analysis make sure you understand what the numbers represent. Often values are listed without explanation and may be total porosity, gas-filled porosity or some other representation of the pore space. For dry gas systems if you are not modeling the flow back period after fracturing then a single phase model can be used with gas filled porosity. Using matrix porosity as a history matching parameter and paying close attention to its effect is advisable and assists in restraining optimistic forecasts as experience has shown that initial porosity estimates are frequently too high.

4. **Matrix permeability considerations** – Advances in core analysis techniques for shale gas reservoirs have provided additional quality data not previously available. Pressure decay permeability seems to give reasonable estimates for matrix values. During history matching, it is difficult to distinguish matrix permeability effects from the observed data and a unique determination is rare. Changes in matrix permeability have little effect on simulated performance until the late time region. Low matrix permeability, such as one nanodarcy, causes a decade’s long forecast to have a never ending slow decrease in the decline rate while higher matrix permeabilities result in steeper late life declines. Use pressure decay permeability if available; otherwise err on the high side to keep from over estimating recovery.

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Table 6—Barnett Best History Match Reservoir Properties by Well

<table>
<thead>
<tr>
<th>Reference Well Name</th>
<th>Lateral Length ft</th>
<th>Spacing X dir ft</th>
<th>Spacing Y dir ft</th>
<th>Perm at Well md</th>
<th>Perm Near Well md</th>
<th>Perm Remaining md</th>
<th>Stimulated Rock Vol acre-ft</th>
<th>Porosity Gas Filled %</th>
<th>Perm md</th>
<th>Total Rock Vol acre-ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bar Well 1</td>
<td>1,900</td>
<td>6</td>
<td>6</td>
<td>0.023</td>
<td>0.023</td>
<td>0.023</td>
<td>3,926</td>
<td>4.1</td>
<td>0.00022</td>
<td>9,334</td>
</tr>
<tr>
<td>Bar Well 2</td>
<td>1,900</td>
<td>6</td>
<td>6</td>
<td>0.019</td>
<td>0.019</td>
<td>0.019</td>
<td>5,670</td>
<td>4.1</td>
<td>0.00022</td>
<td>9,334</td>
</tr>
<tr>
<td>Bar Well 3</td>
<td>1,900</td>
<td>6</td>
<td>6</td>
<td>0.017</td>
<td>0.017</td>
<td>0.017</td>
<td>9,334</td>
<td>4.2</td>
<td>0.00022</td>
<td>9,334</td>
</tr>
<tr>
<td>Bar Well 4</td>
<td>1,900</td>
<td>6</td>
<td>6</td>
<td>0.017</td>
<td>0.017</td>
<td>0.017</td>
<td>9,334</td>
<td>3.5</td>
<td>0.00022</td>
<td>9,334</td>
</tr>
</tbody>
</table>
5. **Relative permeability** – Until reliable relative permeability measurement procedures become available, pick a set of curves and use them for all wells. Use gas and water relative permeability curves that are not unusually low or rapidly changing at higher gas saturations as this artificially introduces another parameter. Absent significant matrix compression, long term depletion results in small increases in water saturation. Always make a plot of water yield, Stb/MMcf, from the production data to distinguish free water flow from water condensing from the vapor phase in surface facilities. For matrix flow considerations, water relative permeability should be at or near zero at initial water saturations. Long term continued free water production is most likely a fracture system connecting to a water zone.

6. **Capillary pressure** – Capillary pressure data is now available from modern core analysis. If you are modeling flow back after fracturing, you must include capillary pressure. Correct laboratory determined capillary measurements to reservoir fluid conditions. Initialize the model at gravity – capillary pressure equilibrium and set the gas water contact at a level that establishes initial water saturation values comparable to reliable petrophysics. Capillary pressure wetting phase imbibition is a powerful force. Matching water and gas rates during the flow back period often results in useful insights to fracture permeability and fracture density.

7. **What to match** – It all depends on the quantity and quality of data available. If you have quality flow back information, hourly gas and water rates along with choke sizes and flowing pressures, try to match this first. If not, then determine from production data if the well is still experiencing free water flow. For wells where the fracture treatment did not connect to a water zone, my experience has been that after the first couple of weeks of gas and water flow and if the gas rate has dramatically increased, then history matching can proceed using only gas rates and pressures. If bottomhole pressures are changing with time then my preference is to fix flow rates and match pressures. Plotting gas rate and pressure as a function of cumulative gas instead of time gives more insight into reservoir mechanisms. If only gas rates are available, then you should not attempt a history match unless you are fairly certain the well is producing against a minimum constraint. Look for larger choke settings and near constant flowing tubing pressure and calculate the flowing bottomhole pressure. Use a constant bottomhole pressure as the production constraint and match flow rates.

8. **Fracture complexity and the single wing debate** – Microseismic showing a large number of events automatically translates to complex fracture systems in the mind of a person charged with simulating gas shales. The complex fracture system is usually modeled as a conjugant set of right angle fractures. For vertical wells, we have been unable to obtain adequate history matches without using conjugant right angle fractures. Use of winged fracture planes in vertical shale gas wells does not seem to be able to explain observed flow rates and pressures. For long lateral horizontal wells with many fracture stages this issue may not be as important. Parametric studies indicate that the “off perpendicular” fracture density has much less effect on simulated performance, however, there needs to be some number of off perpendicular fractures to achieve a match. Microseismic is also useful in estimating the width of stimulated area.

9. **Understand who does what to whom** – To prevent many hours or days of frustrating simulation start your work by a systematic investigation of the effect of each unknown. Use Fig. 1 as a guide to variables and their interactions, take careful notes and produce hard copy plots for future reference during the matching process. A frequent mistake is to try to fine tune a match with a variable having little effect on a specific time period but a larger effect on other time periods. Understand who does what to whom.

10. **Simultaneous matching of variables** – For manual history matching Rule No. 1 is only change one variable at a time. Changing two or more variables at once increases the clock time of achieving a match, despite your instincts. Assisted or automatic matching can go astray when the signal from a secondary variable is small. A frequent issue with matching multiple variables simultaneously is that a secondary variable during one period becomes a primary variable in another period. A symptom of this issue is when the match is high during one period and low during another. Try breaking the observed data into the early time, middle time and late time regions and matching each separately.

11. **Don’t be afraid if it is hard to match** – When individually matching a group of wells it is common that some wells are easy to match while others seem that no combination of variables result in an acceptable match. Inevitably this means that the model is not representing either the geology or the forces in play in the reservoir. Step back and take a larger view of the process expanding your paradigm of the geology and reservoir engineering issues. Look for possible offset interference, wellbore integrity issues like effective lateral length, nearby faulting, failed fracture stages or the possibility that much of the fracturing occurred on one side of the lateral.

**Model-Based Analysis of Reservoir Performance**

Model-based analysis (or more commonly referred to as Rate-Transient Analysis) of production data has evolved into a distinctly unique tool for the analysis of production data from tight gas/shale gas reservoirs. A comprehensive workflow for model-based analysis of production data can be found in in Ilk et al 2007, where the application was focused on the analysis...
of tight gas reservoir performance using an elliptical flow model. The model-based analysis tools which are most popular are the "RTA" product from Fekete [Fekete, 2010] and the "Topaze" product from Kappa Engineering [Kappa Engineering, 2010].

In this section we provide the model-based analysis of the historical production data combined with the known reservoir and completion data for four horizontal wells with multiple hydraulic fracture treatments in the Barnett Shale Field (TX, USA). These wells vary in vintage from 2006 (at the tail of the first wave of Barnett Shale development using horizontal wells) to late 2007, where more fracture stages and (in general) more proppant were deployed. The "Topaze" product (Kappa Engineering, 2010) was used, and the well completion information as taken from completion reports was used as "ground truth" in the Topaze model. The reservoir and fluid properties were obtained from industry and literature sources, and we are comfortable with all of the input data we have used for this particular case.

The results of these analyses are given in the table below:

<table>
<thead>
<tr>
<th>Well</th>
<th>k (md)</th>
<th>x_f (ft)</th>
<th>F_C (md-ft)</th>
<th>S_f (dim-less)</th>
<th>G (BSCF)</th>
<th>A (acres)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bar Well 1</td>
<td>0.0025</td>
<td>150</td>
<td>0.1</td>
<td>0.05</td>
<td>3.2</td>
<td>33</td>
</tr>
<tr>
<td>Bar Well 2</td>
<td>0.0025</td>
<td>200</td>
<td>1.0</td>
<td>1.5</td>
<td>5.0</td>
<td>52</td>
</tr>
<tr>
<td>Bar Well 3</td>
<td>0.0020</td>
<td>100</td>
<td>0.05</td>
<td>0.8</td>
<td>1.5</td>
<td>23</td>
</tr>
<tr>
<td>Bar Well 4</td>
<td>0.00075</td>
<td>200</td>
<td>0.12</td>
<td>0.25</td>
<td>IA (1.5)</td>
<td>IA (23)</td>
</tr>
</tbody>
</table>

The analyses/interpretation plots for each of these are given sequentially for each case — in Fig. 20 we present the case of Bar Well 1 where we note immediately the signature of an apparent boundary-dominated flow regime (evidenced by the sharp, "unit-slope line" shown on the "log-log" and "Blasingame" plots). We suggest that this may be an artifact, but it has a strong appearance as boundary-dominated flow, and this regime is required to achieve an overall match of the data. Bar Well 1 is the oldest, longest producing well in the group, so some evidence of depletion is expected. The fracture conductivity estimate (0.1 md-ft) is low by comparison to most cases, and we admit that it is difficult to distinguish much character in the earliest data trends.

In Fig. 21, we present the results for Bar Well 2, and we note that this well gives evidence of significant skin damage as evidenced by the large separation of the pressure integral function (in green) and the pressure integral derivative function (in red) at early times. For Bar Well 2, as with Bar Well 1, we note an apparent boundary-dominated flow regime — and we would comment that the signature observed in this case also appears plausible given the duration of production and the strong character of the plotting functions at late times on the "Blasingame" plot. The production (rate) history match is quite good for this case, and the pressure match is probably "fair" at best. It is worth noting that portions of the pressure history are missing and a linear interpolation was used to provide surrogate values for the missing data. This well has the highest gas-in-place estimate (approximately 5 BSCF) for any of the Bar Wells. For reference, Bar Well 2 is essentially the same vintage as Bar Well 1, where the start dates of production for each well were within about a month.

The Bar Well 3 case is a "new" well, with six fracture treatment stages (as opposed to four stages for Bar Wells 1 and 2), as such, we would expect less influence of skin and a better overall flow profile. As we note in Fig. 22, the performance for this well is almost perfectly represented by the prescribed well model of a horizontal well with multiple fractures. Of particular note are the excellent matches of the data — all plots indicate very good matches and even with significant noise in the data, the "Blasingame" plot illustrates an essentially perfect match. Ironically, this well required a very low value of fracture conductivity as well as a significant skin factor to achieve this match, suggesting that the stimulation treatment could have been deployed more effectively. As a conclusion of this analysis, we would suggest this well to be a possible candidate for re-stimulation.

In Fig. 23, we observe a near-perfect signature of a horizontal well with multiple hydraulic fractures in an infinite-acting reservoir. There are some minor distortion effects at early times (presumed to be well clean-up effects), but the important aspect of this case is that does not appear to be evidence of boundary-dominated flow behavior in the data. In this case, the analysis of Bar Well 4 gave a much lower permeability estimate. It is possible that the early time match could be slightly improved (see a bit of mis-match on the "Blasingame" plot at early times), but we believe that the overall analyses is balanced and is as accurate an interpretation/analysis as the quality of the field data permit. As Bar Well 4 was matched with using an infinite-acting reservoir condition, we systematically adjusted the "boundaries" of the system to achieve a minimal deviation match, which implies the smallest reservoir that could generate this behavior. The result of this exercise was a gas-in-place estimate of 1.5 BSCF and a drainage area estimate of about 23 acres.

We have an appropriate level of confidence in the results obtained using modern production analysis methods, in the case of the Bar Wells, the most significant issue is probably that of the missing pressure history data. There are uncertainties
inherent in the reservoir properties used, as well as the assumptions of the reservoir model used to match these data. As one considers the use of modern production data analysis tools, one can be confident in the tools and methodologies, but vigilance and scrutiny must guide the user in reviewing the production data itself, as well as the stimulation and completion history data.

**Decline Curve Analysis**

While simulation and rate-transient analysis better represent the physics of flow, the difficulties of use are prohibitive for most common applications. The data and time requirements of the techniques are much higher, and the available software is not integrated with economic analysis software. Consequently, as a matter of practical limitations, decline curve analysis is applied for the large majority of non-research uses.

Of the forecasting options commonly available in decline curve software, the hyperbolic form of the Arps equation, with a final minimum decline rate, is almost universally used for the forecasting of shale gas reserves. It is simple, available, and it can fit reasonably well the early time behavior which is available for analysis. Despite its ease and ubiquity, the Arps formulation has scientific limitations. As a practical matter, its use creates the risk, even the probability, of serious over-estimation of reserves.

It is well-known that the Arps formulation of decline behavior is supported by theory only for boundary-dominated flow and only when the hyperbolic exponent is between 0.0 and 1.0. [e.g. Arps 1945, Fetkovich 1990, Cheng et al.] It has been established that higher b-factors pertain to transient or heterogeneous, flow behaviors. [e.g. Fetkovich 1987] Unsurprisingly, it has further been established that in tight and shale gas reservoirs, the b-factor trends downward for most of production time, though it may increase in late time. Notwithstanding these published results, it is our observation that the most common method of shale gas forecasting involves a single b-factor for all production times. Assumed values are usually above 1.0 and often around 1.5.

More to the point, a number of papers have recently described how the use of Arps equation in low permeability situations can seriously over-estimate reserves. These prior works have been based on synthetic (simulated) data as well as actual production data for both tight gas and shales. They have shown, among other things, that Arps formulation with a high b-factor can overestimate reserves by a factor of 2 to 3 or more, especially when there is short production history. Due to the constraints of its scientific underpinnings and problematic application, it has been suggested that the Arps equation may not qualify as a “sufficiently reliable technology” as defined and required by the United States Securities and Exchange Commission for the reporting of reserves. [Lee and Sidle, 2010]

Anyone who has used a curve-fitting program realizes that many algebraic forms can be made to fit any given data set with reasonable accuracy and without necessarily any theoretical underpinnings or predictive ability. The common method of forecasting shale gas production might be viewed in the same way. Our review of thousands of production decline curves does, in fact, show that the Arps equation can very frequently be used to fit some or all of the historical production data. Forecasting, however, often uses only a few months or years of production data to forecast for several decades. If the Arps equation is to be used as a matter of practical necessity, then it should be done circumspectly.

On the other hand, a new formulation of the decline equation has recently emerged which is likely to replace Arps for shale gas projections. It is commonly called “power law exponential” or “stretched exponential.” Numerous papers have described its formulation and application, but it has yet to be deployed in commercial software for extensive testing. Small-scale testing has indicated its usefulness, particularly with less data than is necessary for hyperbolic analysis.

**Use of Hyperbolic Decline**

Experience and other literature has shown that a hyperbolic Arps with a minimum decline rate can be used to represent with reasonable accuracy shale gas production predicted more scientifically using simulation. [Kupchenko et al 2008, Cheng et al. 2008a] The curve-fit, though, may not be complete or easy to accomplish, sometimes sacrificing very early time or late time matches to better fit early and middle time which account for much of the total recovery.

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4 It was originally presented by Ilk et al. 2008, though an equivalent form was proposed by Valko 2009. More recently, the equation has been expanded in Ilk et al. 2010.

5 See also Mattar et al 2008, Johnson et al 2009, and, for tight gas only, Currie et al 2010.
The hyperbolic fit is not always straightforward because the form of the equation doesn’t capture all that is happening in the reservoir. Arps hyperbolic form assumes that the first derivative of the decline rate (i.e. the b-factor) is a constant. It has been established in literature and experience that, for low permeability reservoirs and shales, the b-factor changes with time, and our work shows the same thing. The b-factor in all examined cases decreases at early times, and it frequently increased at late times. Consequently, a long-term forecast may be expected to exhibit a lower b-factor than early production, and the gas rates at the latest times may be higher than the Arps equivalent. Moreover, simulation of shale gas production suggests it never truly reaches a final exponential decline. The rate of change of the decline, however, diminishes. The final decline rate, in a curve fit of synthetic data, may be used to emulate the late time behavior when the b-factors are much less than early time.

Using the simulated Barnett and Haynesville wells as a starting point, we created the single-variable, parametric variations described above. Figs. 24 and 25 show the simulated projection as data points and show the Arps curvefit as a line, both for the base case Barnett simulation. Figs. 26 and 27 show equivalent data for the base Haynesville run. The specifics of the curve-fits can be found in Tables 2 and 3. For these examples shown, as well as other work performed by the authors, it is possible to use the hyperbolic equation to represent well the simulation-based forecasts which more closely represent the physical situation. There are some cases, however, in which the fits are more crude than those shown. It may be noted that the final decline rate of 0% was based on the curve-fitting and not for forecasting reserves and that the definition of initial decline may vary between software programs.

Fitting of decline equations to simulated forecasts in gas shales shows that the decline rate does not commonly reach a truly constant figure, i.e. boundary-dominated flow. Instead, the decline rate is always shallowing, though the change may be very small. Simulations have often shown that the decline rate towards the end of the forecast is often on the order of 2 to 6%. Shale production with small amounts of liquids may exhibit meaningfully steeper declines.

It should be noted that, since the parametric study only adjusted one variable at a time, the range of outcomes will not be as broad as those seen in the field. It is also worth noting that, since the base case was centered around the matching parameters for a few cases, the decline parameters shown should not be extrapolated to the entirety of either play.

**Inputs to hyperbolic equation**

In the application of hyperbolic decline, there are only four basic inputs: initial rate, initial decline, hyperbolic exponent (b-factor), and final decline rate. The initial rate is usually established shortly after production begins. (More on choosing initial rate below.) The initial decline rate, within a reasonable band of uncertainty, is established a few months after the initial rate. Due to data limitations, the final decline rate may be taken from analysis of simulation or RTA results, by analogy (occasionally), or from a conservative, unfounded assumption.

Shortly after production begins, the b-factor is the most volatile control on reserves, having the largest unconstrained impact on the expected ultimate recovery. The b-factor unfolds slowly over years or decades. During early times, there is a very sensitive trade-off between small changes in initial decline rate and large changes in b-factor. Since the form of the equation is an approximation of and not based on actual, long-term reservoir dynamics, the more precise fit of historical production is not necessarily the more predictive of future production. Roughly equivalent quality matches of historical production can result in radically different estimates of ultimate recovery. See, for example, Figs. 28 and 29.

Sadly, this critical input sometimes receives the least analysis. Some have asserted, and in fact used, the same b-factor for all wells at all times and sometimes in all shale plays. This is evidently the cause, for example, of very tight correlations sometime reported between early production rates and ultimate recoveries. First principles dictate that each well will have its own unique characteristics and responses to surface operations, and therefore, its own b-factor. Though an average well production may have usefulness, there is no empirical or theoretical basis to assume the same b-factor for all producing wells.

Even assuming that future production can be accurately represented by a single b-factor, there is no basis for the assertion of a constant b-factor across an entire region much less across several shale plays. By analogy to the literature concerning layered reservoirs [e.g. Fetkovich 1990], one would expect that the b-factor would relate to the relative properties of the fracture system compared to those of the matrix. Simulation has validated that the primary controls on production during the early transient periods different from the primary controls during later flow periods, and the controls are not necessarily related to each other. Finally, empirical review of actual production data demonstrates a wide range of observed b-factors, often from 0.8 to 1.5 over the early years of production. In some cases, there are unambiguous and persistent patterns of b-factors much below 0.8 even in relatively early times.
When performing decline analyses on producing wells, earlier time data is less useful for the estimation of b-factors. Though the assumption underlying all decline analysis is that of constant operating conditions, flowing pressures may, in fact, be changing during early production. Until a minimum flowing constraint is reached, production rates are a function of reservoir and operational factors. If the drawdown is less than it can be, then rates are also less. Decreasing flowing pressures prop up rates, causing the declines to look less than they otherwise would. Fortunately, the reservoir pressures and line pressures in most gas shale plays are such that the minimum flowing tubing pressure is reached relatively quickly. In the Haynesville shale, however, wells may operate with continually decreasing flowing pressures for a year or more. 

On the other hand, early production is dominated by the permeability of the fracture system, fracture spacing and effective lateral length. Certain of these effects play out in a short time as other properties also begin to influence rate. The decline rate, often very high in the first days of production, slows quickly in the first days to months. The decline during the earliest period of transient flow can be much greater than the decline after a couple of months when different parameters begin influencing the rate of decline. After that time, the rate of change of the decline slows considerably. That is, the b-factor generally declines. This unusually high decline in early time makes it problematic, even misleading, to quote or to use the earliest production rates as “initial rates” for the well. Trying to honor the initial rate and b-factor demonstrated in the earliest days to months of production often leads to higher estimates of b-factors than should be expected over the producing life of the well and thus to inappropriately high reserves. 

When trying to determine an appropriate b-factor from production data, later life data should be favored. Because the b-factor represents the first derivative of the change in the decline rate, it is easy to understand why more data is useful to identify an appropriate b-factor. Beginning analysis with the oldest wells can help guide the analyst in the forecasting of wells with less data, though an iterative process may be necessary. It may also be noted that sometimes very similar ultimate recoveries can be reached with somewhat different combinations of b-factors and initial declines. 

As a rule of thumb, it is often difficult to constrain even modestly a hyperbolic exponent with less than a year of well-behaved production. In cases where the initial decline is shallow, longer periods may be necessary to recognize the uniqueness of the change in decline. Even when a year of data is available, there is usually significant uncertainty in the initial decline/b-factor trade-off. In the absence of separate data to constrain the b-factor, a preference should be given toward the middle or lower range of b-factors that result in a reasonable consistency with history. 

Empirical data suggests that fracturing a nearby well can affect the production from a pre-existing well, and our analyses corroborates this assertion. The fracture network created by a new well can intersect a pre-existing network and change drainage patterns, sometimes for the better and sometimes for the worse. Similarly, though not treated in detail here, simulation has established that re-fracturing a shale well changes the characteristics of its fracture network. Consequently, the time necessary to establish a pattern of production starts over after one of these events. 

Since simulation or RTA analysis is preferable but not practical on a large number of wells, those techniques may be used to forecast full life production for a limited number of wells. The resulting forecasts for individual wells or a range of cases may be curve fit to gain insight into the implied, long term decline behavior. Figs. 24 and 26 mentioned above demonstrate curve-fits of synthetic shale gas production forecasts for a parametric range of key inputs. The effect of different variables on the decline character is consistent with expectations, given the time periods which they most affect. 

**Late-life considerations**

Shale gas wells are generally expected to produce much longer than most conventional reservoirs. In fact, engineers often carry shale forecasts out to 50, 60 or even 75 years of future production. For the purpose of discounted cash flow analysis, the late life production does not contribute a great deal of value, and the length of the forecast may not be material. For the purpose of reporting reserves, though, volumes forecasted to be produced between 20 and 60 years in the future are reported equally with volumes expected to be produced in the first few years of production. Volumes after year 20 can be as high as about 25% of the total reserve volume, depending upon the degree of flattening and the assumed final decline rate. A prudent and conservative application of Arps equation would not use as low a final decline rate as the 2% suggested by simulation.

Because the forecast extends over such a long time, small changes in the parameters at the beginning of the forecast can translate to significant differences in reserves. The long periods of low-decline production also make the reserves figure sensitive to minor changes in minor variables such as final decline rate, escalation of gas prices and even escalation of operating costs. **Fig. 30** demonstrates an example of such sensitivity. Of course, little data is available to constrain estimates of gas price, operating costs and production decline rates between 20 and 60 years in the future for these plays which are often in early stages and developing rapidly.

It should also be noted that some plays and/or some areas produce relatively minor volumes liquids. If the gas production is not entirely dry, then the ability to lift the liquids can be a much more important constraint than the final decline rate of the gas production, often causing significant interruptions, decreased production and increased costs much earlier in life.
Average Well Analysis

The discussion above focuses on the treatment of individual producing wells using decline analysis. Forecasting undrilled wells, however, is the more significant challenge since a single production curve is often applied to hundreds or thousands of postulated locations. This fact of life results in a concentration of risk into a single set of assumptions. When available, especially in early production periods, simulation and RTA offer more unique and rigorous solutions. Decline analysis nevertheless retains usefulness, and the most common technique consists of a “type curve” or “average well.” For the purpose of creating an average well, the most salient issue is similarity to the undrilled area and the second is accuracy of forecasting of the analog wells.

Choosing analogs

Similarity of available producing wells to postulated locations may be difficult to ascertain due to the many variables which can affect (or which are thought to affect) production. The many variable may include, for example, horizontal or vertical orientation, local geologic conditions, lateral length, completion date (proxy for completion design or other parameters), operator (also proxy for completion design), distance between wells, whether wells are simultaneously fractured, azimuthal orientation of lateral, number of fracture stages, zone in which the lateral is landed and, of course, the design of the fracture treatment. Unfortunately, the data and time necessary to discriminate all of these and other factors is usually prohibitive except when evaluating a single new technique or assumption.

Studies by others [Awoleke and Lane, 2010] and our own work have demonstrated that a few variables have greater effect than others. Horizontal/vertical orientation, obviously, and local geology are among the most important factors. Not only are horizontal wells much more productive, their decline parameters are not the same as those of vertical wells, and they cannot be used as analogs for such. Lateral length can also systematically affect average production. It may be expected that a 4000 foot lateral with 12 stages of fracturing will produce about twice as much as a 2000 foot lateral with 6 stages. When the average lateral length changes systematically such as it has in the Fayetteville Shale, it is particularly important to normalize results for lateral length.

Local geology turns out to be the next biggest factor. One can easily observe large-scale variations in the productivity of shale reservoirs. From county to county, even with many apparent similarities in the formation, there can be marked differences in productivity. Within a county, one can often observe a number of areas with systematically higher or lower productivity than the rest of the county. See, for example, Fig. 31. Sometimes these differences are identifiable caused by differences such as increasing thermal maturity, higher concentration of karsting, absence of a frac barrier, or proximity to a fault system. In other cases, though, the differences belie obvious explanation based on extrinsic or macroscopic properties of the rock. The intrinsic nature of the shale itself, and the variation of the same, can be the decisive factor. From a strictly anecdotal point of view, areas of similar productivity often stretch over an area from a few tens of thousands of acres to a few hundred thousands of acres. For the purpose of gathering enough analog data, it is may not be necessary to include nearly so much area. Where sufficient data exists, areas of similarity can often be identified by objective and accessible measures of productivity such as six months cumulative production. When data is particularly sparse, such as early in a play, one should beware of extrapolating well results over too wide an area.

It has been argued in public forums that completion design can be proprietary and superior and, equally, that completions improve continuously with time. In our analyses, however, neither has proven out as strongly as asserted. Within areas of geologic similarity, objective production indicators for wells completed by major operators is often quite similar. (Less experienced operators or those with fewer wells may show more variation, typically less production.)

Historically, shale well productivity has taken several step changes upward, and there is always a steep learning curve in the early life of a shale play or, sometimes, in a new area of a shale. Some shale plays have seen significant improvements in completion design but still not proved economically viable. Even for economically viable plays with longer histories, well productivities have not always improved continuously. In some cases, smaller improvements in productivity have been seen. In other cases, well productivity has plateau’d or even declined. Depending upon how the area is defined, increases or decreases in the average well productivity over time may be related to drilling activity moving from one part of the area to a geologically different part of the area. In short, the common axiom of continually improving technology and improving recovery is not a dependable one.

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6 See also Walser and Pursell 2007 and, by inference, Wright 2008 and Valko 2009.
7 Our observations are consistent with the study of Valko 2009.
Even within areas of relatively similar geology and production characteristics, there is a very wide range of well results. Figs. 32 and 33 show histograms of objective measurements of productivity within areas determined to be relatively similar in character.

Certain other issues may be a major effect on productivity, but the lack of meaningful variation among wells in the data set renders the issues moot for type curve analysis. The list and discussion above is not definitive, only indicative. The engineer constructing an average well should examine potential drivers of production and adjust his analysis in response, recognizing that this may be an iterative or multi-step procedure.

**Accuracy of forecasting**

Normalized, average wells have often been created by engineers using actual production data alone, without reference to forecasts for any single well. It is accepted that the tail-end of the resulting average production is less reliable, and engineers may choose not to honor the average production after a certain, arbitrary point. This process, though, often results in an average well with recovery higher than that forecasted for individual wells. When a type curve is created from actual production including forecasts of future production, the resulting average is much more similar to the average estimated ultimate recovery of individual wells. Figs. 34 and 35 compare two average well curves for the same area, one constructed with forecasts and one without.

The two types of average production (with and without forecasts) are practically identical at the beginning, but they often diverge as the well count drops off in the case without forecasts. Including forecasts in the average well often causes the average to trend lower. The average well production created without forecasts has been found often to be up to about 25% greater than the average well profile created with forecasts. It seems that the greater discrepancies occur in situations with greater b-factors, and sometimes the discrepancy is minor.

There are several reasons that the tail-end of the average production curve might be higher than for an average of forecasted production. Perhaps early completions (the ones still producing at the later times in the time-shifted, normalized curve) were less efficient and thus more productive later in life. Perhaps the nature of averaging causes more distortion later in life when there is more discrepancy between the best producers and bulk of producers. Perhaps it is a systematic, conservative bias expressed on a well-by-well basis that causes the discrepancy. Whatever the cause, it is preferable to honor the average estimated ultimate recovery determined for actual wells than for a conglomerate of wells.

For the creation of the average well, it is recommended to begin with a careful by-well production forecast for each well deemed to be analogous. Sometimes the process is iterative, requiring some analysis to determine which are most similar. It is also recommended to begin the analysis with the oldest wells first in order to gain the most guidance from the most unique behavior. When forecasts are created and reserves estimated using the same economic inputs as will be used in the forecast of undrilled wells, then one can examine the distributions of estimated ultimate recoveries. Even for a relatively similar geologic area, the range of recoveries is usually quite broad, such as that shown indirectly in Figs. 34 and 35 cited above. This fact which has implications for the investment in a portfolio of shale wells and which may be considered in the use of the resulting type curves. [See also Wright 2008, Lee and Sidle 2010]

**Conclusions**

**Summary:** Reserve analysis for shale reservoirs can be conducted in a consistent and scientific method, but the engineer must use appropriate techniques and use them in appropriate manners.

**Conclusions:** We state the following conclusions based on this work:

1. The engineering aspects of reserve analysis are still emerging for shale gas.
2. Due to the variability in reservoir parameters, completion techniques and operating conditions, production forecasts should be performed on a well by well basis if possible.
3. Early production behavior is strongly influenced by operator choices and other changes in surface production constraints. Simulation and rate-transient analysis requires detailed daily flow rates, flowing tubing pressure, choke size and other surface operating conditions.
4. Different periods of production are controlled by different components of the production system, and transients persist for very long periods of time. Accurate analyses/interpretations require sufficient production history and detailed production information to test adequately the separate variables which control performance and ultimate recovery.
5. Simulation and rate-transient analysis are valuable tools in understanding reservoir mechanisms. However, results from simulation or rate-transient analysis should be tempered with sound engineering judgement.
6. Simulation, rate-transient analysis and decline curves can be used to forecast production from shale wells with reasonable consistency when used appropriately.

7. If the quantity and quality of data is sufficient to use all three methods, then, of the methods, decline curve analysis is likely to be the most subject to error, especially during early times.

**Recommendations:** We propose the following recommendations based on this work:

1. When possible, we suggest that simulation or rate-transient analysis be used to develop an understanding of reservoir characterization and recovery mechanisms. Lessons learned from the proper application of these techniques provide guidance to decline curve analysis. Decline curve analysis should be informed by simulation or rate-transient analysis when feasible. Additionally, there are techniques to improve the reliability of decline curve analysis.

2. In the absence of detailed well and production information and surface operating conditions, simulation and rate-transient analysis should be used with caution. In all instances, inputs to the analyses should be tempered and constrained by other measurements and sensible limits.

3. Additional research should be conducted into the power law exponential formulation of decline analysis, and additional engineering tools need to be developed for the deployment of the best techniques.

4. An analyst should recognize the significant variability in production from well to well and area to area in a reserve analysis.

**Acknowledgements**

We wish to thank El Paso Production Company, J-W Operating and EXCO Resources for their generous contribution of data. We also wish to thank Mr. Stephen Duncan, Dr. Dilhan Ilk and Mr. Dave Symmons for the generous contributions of their time.

**Nomenclature**

**Variables**

\[ \hat{a} = \text{Model parameter, (md-D^2/MSCF)} \]

\[ A = \text{Drainage area, ft}^2 \]

\[ b = \text{Arps' decline exponent, dimensionless} \]

\[ \hat{b} = \text{Rate-time equation model parameter} \]

\[ \hat{b} = \text{Model parameter dimensionless} \]

\[ \hat{c} = \text{Model parameter dimensionless} \]

\[ \hat{d} = \text{Model parameter dimensionless} \]

\[ D = \text{Reciprocal of loss ratio, D}^{-1} \]

\[ D_i = \text{Model parameter, D}^{-1} \]

\[ D_n = \text{Rate-time equations model parameter, D}^{-1} \]

\[ \hat{D}_i = \text{Rate-time equations model parameter, D}^{-1} \]

\[ EUR = \text{Estimate of ultimate recovery, BSCF} \]

\[ F_c = \text{Fracture conductivity, md-ft} \]

\[ G = \text{Gas in place} \]

\[ k = \text{Formation permeability, md} \]

\[ L_w = \text{Horizontal well length, ft} \]

\[ n = \text{Time exponent, dimensionless} \]

\[ n_f = \text{Number of transverse hydraulic fractures intersecting the horizontal wellbore} \]

\[ q = \text{Production rate, MSCF/D or STB/D} \]

\[ \hat{q}_i = \text{Model parameter, MSCF/D or MSCF/Month} \]

\[ s_f = \text{Skin factor, dimensionless} \]

\[ t = \text{Production time, days} \]

\[ x_f = \text{Fracture half-length, ft} \]

**Greek Symbols**

\[ \hat{\alpha} = \text{Model parameter, dimensionless} \]
\hat{\beta} = \text{Model parameter, dimensionless}
\tau = \text{Characteristic time parameter, months}

References

Fekete and Associates: "Rate Transient Analysis (RTA)" software, Calgary, AB Canada, 2010.
Fig. 1—Matching Parameters of Horizontal Wells

Fig. 2—Haynesville Parametric Runs
Fig. 3—Barnett Parametric Runs

Fig. 4—Haynesville History Match Well 1
Fig. 5—Best Match Well 11

Fig. 6—Best Match Well 23
Fig. 7—Best Match Well 25-2

Fig. 8—Best Match Well 26
Fig. 9—Well 2 Effect of Stress

Fig. 10—Best Match Well 28H-1
Fig. 11—Best Match Well 28-1

Fig. 12—Matched Wells Forecast
Fig. 13—Matched Wells Forecast EUR

Fig. 14—Bar Well 1
Fig. 15—Bar Well 2

Fig. 16—Bar Well 3
Fig. 17—Bar Well 4

Fig. 18—Bar Matched Wells Rate Forecast
Fig. 19—Bar Matched Wells Cum Forecast

**Analysis Results: Bar Well 1**
- $k = 2500 \times 10^{-6}$ md
- $n_f = 16$ (4 fracture stages)
- $x_f = 150$ ft
- $F_c = 0.1$ md-ft
- $s_f = 0.05$
- $G = 3.2$ BSCF
- $A = 33$ acres

a. "History Plot" for Bar Well 1 (Barnett Shale). [Kappa Topaze Software]


c. "Blasingame Plot" for Bar Well 1 (Barnett Shale). [Kappa Topaze Software]

Fig. 20—"Model-based" production analysis — Bar Well 1 [Barnett Shale Field (TX, USA)].
Fig. 21—“Model-based” production analysis — Bar Well 2 [Barnett Shale Field (TX, USA)].

Analysis Results: Bar Well 2
- $k = 2500 \times 10^{-4}$ md
- $n_r = 16$ (4 fracture stages)
- $x_r = 200$ ft
- $F_c = 1.0$ md-ft
- $s_f = 1.5$
- $G = 5.0$ BSCF
- $A = 52$ acres

Fig. 22—“Model-based” production analysis — Bar Well 3 [Barnett Shale Field (TX, USA)].

Analysis Results: Bar Well 3
- $k = 2000 \times 10^{-4}$ md
- $n_r = 24$ (6 fracture stages)
- $x_r = 100$ ft
- $F_c = 0.05$ md-ft
- $s_f = 0.8$
- $G = 1.5$ BSCF
- $A = 23$ acres
Fig. 23—"Model-based" production analysis — Bar Well 4 [Barnett Shale Field (TX, USA)].

**Analysis Results**: Bar Well 4
- \( k = 750 \times 10^{-6} \) md
- \( n_f = 24 \) (6 fracture stages)
- \( x_f = 200 \) ft
- \( F_c = 0.12 \) md-ft
- \( s_i = 0.25 \)
- \( G = \) Infinite-Acting (> 1.5 BSCF)
- \( A = \) Infinite-Acting (> 23 acres)

Fig. 24—Semi-log rate-time plot of simulated forecast (dots) and Arps curve fit (line) for the base case Barnett well.

c. "Blasingame Plot" for Bar Well 4 (Barnett Shale). [Kappa Topaze Software]
Fig. 25—Cumulative production vs. time for simulated forecast (dots) and Arps curve fit (line) for the base case Barnett Well.

Fig. 26—Semi-log rate-time plot of simulated forecast (dots) and Arps curve fit (line) for the base case Haynesville well.
Fig. 27—Fig. 25—Cumulative production vs. time for simulated forecast (dots) and Arps curve fit (line) for the base case Haynesville Well.

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<th>Hyperbolic Exponent</th>
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<tr>
<td>Low</td>
<td>75</td>
<td>0.7</td>
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<td>High</td>
<td>99</td>
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<td>2.9 Bcf</td>
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Fig. 28—Example of uncertainty in reserve figures based on hyperbolic exponent, Barnett Shale well A.
Fig. 29—Example of uncertainty in reserve figures based on hyperbolic exponent, Barnett Shale well B.

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<th>Initial Decline</th>
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<tr>
<td>Low</td>
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<td>0.7</td>
<td>1.3 Bcf</td>
</tr>
<tr>
<td>Mid</td>
<td>88</td>
<td>1.3</td>
<td>2.2 Bcf</td>
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<tr>
<td>High</td>
<td>97</td>
<td>2.0</td>
<td>3.0 Bcf</td>
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Fig. 30—Example of the effects of late life considerations on reserve estimates, Barnett Shale well B.

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<tr>
<th>Years</th>
<th>Min. Decline</th>
<th>OPEX</th>
<th>EUR</th>
<th>Reserves</th>
<th>% Incr. Reserves</th>
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<td>28</td>
<td>4%</td>
<td>small esc.</td>
<td>2.3 Bcf</td>
<td>1.8 Bcf</td>
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</tr>
<tr>
<td>40</td>
<td>4%</td>
<td>no effect</td>
<td>2.6 Bcf</td>
<td>2.0 Bcf</td>
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</tr>
<tr>
<td>60</td>
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<td>no effect</td>
<td>2.8 Bcf</td>
<td>2.3 Bcf</td>
<td>+28%</td>
</tr>
<tr>
<td>60</td>
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<td>no effect</td>
<td>3.1 Bcf</td>
<td>2.5 Bcf</td>
<td>+43%</td>
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Fig. 31—Classed bubble map of six months cumulative production per foot of lateral length.

Fig. 32—Histogram of six months cumulative gas production per foot of lateral length for a 100,000 acre area of high productivity in the Barnett Shale.
Fig. 33—Histogram of six months cumulative gas production per foot of lateral length for a 50,000 acre area in the Fayetteville Shale.

Fig. 34—Example of a Barnett Shale type curve generated using only actual production data.
Fig. 35—Example of a Barnett Shale type curve generated using actual production data plus production forecasts.