Prices and Profits: US Shale Gas

Bill Holland, Associate Editor, Gas Daily

Despite warnings that the US shale gas industry is a giant Ponzi scheme, major oil companies continue to make major investments. It’s certainly true that US natural gas prices have fallen—the product of shale gas’s own success—but profits and costs vary widely between plays and are dependent on a number of variables. Key to the debate over future profits is whether decline rates are linear or hyperbolic.

Reading the headline news about shale gas (and now shale oil) out of the US, one could not be faulted for thinking there’s more than just a little schizophrenia in the public perception of shale plays. Consider: in June, the New York Times, which is no friend to the energy industry, but equally no slacker in the fact gathering business, ran a series of articles relaying the doubts of some investment analysts, US Energy Information “officials” (turned out to be an intern) and petroleum researchers.

Shale is a “Ponzi scheme,” the headline blared—after billions of dollars have been spent on investments in joint ventures and mergers and acquisitions, such as ExxonMobil’s $41 billion takeover of Fort Worth shale gas producer XTO Energy. Unconventional shale wells are more expensive than advertised, sources said, they won’t recover as much gas (or oil) as claimed, and the smaller independents who began the “shale gale” that is an alleged game changer for US energy are just drilling until they can unload their positions on the next available sucker.

And then the New York Times quotes a source saying shale gas is “just like Enron,” the ultimate put-down in the US energy industry. With, or rather despite, this warning, Anglo-Australian mining company BHP Billiton a month later paid $12.1 billion for Houston-based shale oil and gas producer Petrohawk Energy, another takeover of a shale independent by a deep-pocketed major. What’s going on?

Production Boost

What is undeniable is that something has changed in US gas and oil production, a change that became evident in 2008 for gas and in 2009 for oil, according to US Energy Information Administration data. By 2010, the US was producing more gas than ever before, 21.5 Tcf a
year, a 19% increase over 2005, and, after years of decline, onshore oil production had increased 5% over 2005 levels, to 2 billion barrels a year.

Shale is the driver for both. In 2008, the EIA said shale accounted for 11% of the 20.1 Tcf of gas produced in the US, with 7% of that production replacing retiring conventional gas and 4% adding to the US gas supply. In 2009, overall US gas production grew 2% to 20.5 Tcf; 17% of that gas was from shale. The shale gale repeated itself in 2010, according to other estimates, shale accounted for 25% of the 21.5 Tcf produced that year.

For oil, US onshore production continued a decades-long decline until 2009. While the EIA does not yet produce separate shale oil production volumes, most of the increase in output in 2010 is coming from North Dakota’s Bakken Shale. The state’s mineral agency reports that, in 2010, Bakken wells produced 100 million barrels of oil, double that seen at the birth of the play three years ago, almost single-handedly boosting US onshore oil production to 2 billion barrels/year, a 108 million barrel gain since 2005.

**Prices and Profits**

The natural gas revolution brought on by extracting gas from shale formations was born in a US market chronically short of natural gas. Prices ranged from $6/Mcf to $8/Mcf with annual spikes in demand that could double prices in both the winter heating season and the summer hurricane season. Those prices have gone, begging the question of whether shale gas can survive its own success. Can producers coax enough natural gas out of the dense, impermeable shales to make money when prices seem stuck around $4/Mcf precisely because of shale gas’s success?

Simply getting the hydrocarbons out of the ground doesn’t necessarily mean immediate profits, or indeed ever profits. But in the price environment in which shale evolved, the link between increased production and profits was clear. This is a link that some wish financial analysts—with their laser-focus on production and reserve growth—would now break.

Energy consulting firm Wood Mackenzie’s Global head of Consulting, Neal Anderson, said in August that after $90 billion in joint ventures and acquisitions, these stock analysts should stop pumping up the prospects of shale. “The equity analyst community has played a key role in helping fuel the shale gas M&A market, acting as chief cheerleader for shale gas plays,” he wrote in the Oil & gas Financial Journal in August. “Their enthusiasm for reserve bookings and production growth has only recently been replaced with a focus on value, namely an analysis of which companies are actually making money, as opposed to recycling money.”

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<thead>
<tr>
<th>Year</th>
<th>Total gas</th>
<th>Shale gas</th>
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<tbody>
<tr>
<td>2006</td>
<td>15 Tcf</td>
<td>5 Tcf</td>
</tr>
<tr>
<td>2007</td>
<td>19 Tcf</td>
<td>6 Tcf</td>
</tr>
<tr>
<td>2008</td>
<td>20 Tcf</td>
<td>7 Tcf</td>
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<tr>
<td>2009</td>
<td>20 Tcf</td>
<td>8 Tcf</td>
</tr>
<tr>
<td>2010</td>
<td>22 Tcf</td>
<td>9 Tcf</td>
</tr>
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Source: EIA, 2010 data analysts estimates
Anderson said the irony of the multi-billion M&A market for shale gas is that money isn’t being made by big companies swooping in and taking out smaller firms, it’s being made by the smaller firms that got into the shale plays first. According to his analysis, operators are making less than 10% profits on shale plays as they increasingly bid up the price for the service they need—hydraulic fracturing—to get the gas flowing.

But unlike Wood Mackenzie’s nationwide analysis, a deeper look by FBR Capital’s research department shows that profits, like the individual geology of shale plays, varies widely. While some plays tread water at $4/Mcf gas, others still pay out. Some plays make money for their operators at prices as low as $3/Mcf, but some won’t begin to pay out until gas prices get above $5/Mcf. At $6/Mcf everybody sees a comfortable margin, while some will see profits that are double or triple their costs.

**Shale Variables**

There are numerous variables that feed into this profit equation for shales: leasing costs, lifting costs, location and hedging programs. The two latter factors are particularly important and can result in realized prices well above the US nationwide proxy of the NYMEX futures contract.

US independents have a decided edge in that most were first movers in particular plays and leased large amounts of acreage at prices well below those paid by the supermajors and national oil companies such as Norway’s Statoil and China’s CNOOC that came later to the game. While the ExxonMobil-XTO merger pushed prices to $10,000/acre in some plays (Statoil and Reliance in the Marcellus for instance), the sellers, Chesapeake and Atlas (later purchased by Shell), paid a fraction of that amount, often less than $50/acre. In the Marcellus, which even for dry gas remains profitable, finding and development costs for the pioneers—Range Resources, Chesapeake, EQT—are all less than $1/Mcf.

Drilling vertically is the fixed cost to shale exploration and is a function of depth. Because the barely profitable (or money-losing for some) Haynesville Shale in Louisiana is 4,000 to 6,000 ft deeper than other shales, its well costs are higher, often much higher. A $3 million Barnett well that is roughly comparable to a $5 million Marcellus well becomes a $10 million well in the Haynesville, owing to the time and expense of drilling another mile deeper.

Increasing drilling efficiency reduces costs. Shale drillers have become ever better at quickly sinking wells, drill-
ing out horizontal laterals and fracking those horizontal spokes, so much better that in most plays the pipeline and processing infrastructure struggles to keep up. In the Marcellus Shale hundreds of drilled wells are reported to be awaiting completion (fracking) or connection to a pipeline each quarter.

Location narrows profits in the Haynesville and the Barnett when compared with the Marcellus. Most Marcellus gas can be sold into the higher-priced markets of the urban northeast US, while Texas and Louisiana gas competes with conventional and offshore gas at highly liquid trading hubs such as the Houston Ship Channel and Henry Hub. Prices in the northeast US, particularly the New York city-gates, are routinely $1/Mcf higher than the day’s NYMEX futures price for delivery to Henry Hub.

Hedging—locking in futures prices with buyers through swaps and collars—also helps shale producers keep their realized prices high. The US’ top shale producer and number two natural gas producer, Chesapeake Energy, has been particularly adept at keeping its realized prices higher than the NYMEX benchmark. The company adds millions of dollars to the well head price of its gas through hedging, although sharp reversals in prices, as occurred in 2008 when gas prices plunged from record highs, can deeply dent the company’s results when it has to mark its books to market every quarter.

For Chesapeake and other independents, hedging routinely adds $1/Mcf to their realized sales prices. But, as gas prices stay below $5/Mcf and remain stable there, it is becoming harder and harder to find customers willing to lock in higher futures prices.

Shale gas critic Art Berman, quoted extensively by the New York Times and others, uses 2009 well data from both the Haynesville and the Barnett shales (and operators Chesapeake and Devon) to show that the promise of shale is wildly overestimated by producers. Shale gas wells produce at very high rates for the first 12-18 months of their lives, but then decline rapidly. Flows are often reduced 66% from the initial production rate to an inflection point. What happens at that point is where critics like Berman and producers part ways. Berman says the 2009 data shows that the decline of the well post inflection is along a linear slope, constantly and inexorably down, until after 10 years the well is played out.

Since the first year’s high rate pays for the well, the shape of the tail determines it estimated ultimate recovery (EUR) over its life, and thus the eventual profitability of the project. Berman’s linear tail results in EUR’s that are half, by his calculation, what shale producers are telling themselves and their investors.

Berman’s views have been well known in the industry for years and he is a frequent speaker on the conference circuit, but when his analysis found a nationwide audience in the New York Times, the “news” prompted US politicians to call for the US Securities and

3. US shale plays—internal rates of return

<table>
<thead>
<tr>
<th></th>
<th>$4/Mcf</th>
<th>$5/Mcf</th>
<th>$6/Mcf</th>
<th>Projected change in rig count through 2015</th>
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</thead>
<tbody>
<tr>
<td>Haynesville Gas</td>
<td>5.50%</td>
<td>4.30%</td>
<td>26.80%</td>
<td>26.80%</td>
</tr>
<tr>
<td>Barnett Gas</td>
<td>13.60%</td>
<td>24.30%</td>
<td>37.60%</td>
<td>-55% to 25</td>
</tr>
<tr>
<td>Fayetteville Gas</td>
<td>32.50%</td>
<td>58.80%</td>
<td>95.30%</td>
<td>-10% to 25</td>
</tr>
<tr>
<td>Marcellus Dry Gas</td>
<td>62.20%</td>
<td>123.30%</td>
<td>226.20%</td>
<td>+100% to 100</td>
</tr>
<tr>
<td>Marcellus Wet Gas</td>
<td>70.10%</td>
<td>120.40%</td>
<td>196.10%</td>
<td>+100% to 100</td>
</tr>
<tr>
<td>Eagle Ford Wet Gas</td>
<td>60.60%</td>
<td>101.40%</td>
<td>159.50%</td>
<td>+705% to 166</td>
</tr>
</tbody>
</table>

Source: Company reports via FBR Research
Exchange Commission to investigate the reserve reporting and production numbers of shale gas producers. The SEC launched a “fact finding” probe this summer that involved subpoenas for data from several small US independents. The subpoenaed firms pledged to cooperate fully.

The shale gas independents don’t think they have anything to hide. Where Berman and others think old well data shows a linear drop, they point to mounds of data on shale wells dating back a decade. These, they say, show that the production decline is hyperbolic, not linear. Instead of dropping off at a constant rate after the initial flush of high production, the decline curve bends slightly up from linear and trails off slowly over the next 20-30 years, justifying their EUR numbers and projected profits. After all, they say, the well pays for itself in the first year. Every other year after is pure profit.

They are also happy to note that many of Berman’s predictions have been wrong. Gleefully, they point out that, in 2008, Berman predicted that production from the Barnett Shale would top out at 6 Tcf. The play has produced 9.6 Tcf worth of gas through this year and still produces 5.6 Bcf/d.

Liquid Focus

Healthy profits are being made at $4/Mcf gas prices in the Marcellus (a combination of cheap leases, lower costs and proximity to high-priced markets), but those profits get slimmer (although they exist) in Texas’ Barnett and Arkansas’ Fayetteville. Haynesville profits are the thinnest; again, a function of the extra vertical length Haynesville wells require before they can turn to the horizontal plane and penetrate the shale.

US gas producers know that low natural gas prices make their current efforts unprofitable in some locations. They are beginning to shift more and more of their rigs to wetter, oilier prospects such as South Texas’ Eagle Ford Shale and shale oil plays in the Rocky Mountains that appear similar to the wildly successful Bakken Shale of North Dakota. Chesapeake plans to have 75% of its spending and drilling rigs redeployed to the liquid plays. Gas liquids and crude get sold at much higher prices than the associated gas.

The remaining rigs drilling for gas will be focused on wells that hold cheap leases in places like the Haynesville Shale to create the minimal production necessary for compliance with lease terms. Drillers in currently marginal plays like the Haynesville view continued drilling as a purchase of a gas future and a cheap way to maintain their claim to billions of cubic feet of gas that can be booked as reserves.

This suggests that the recovery in US onshore oil production has some legs. Announcing the change in direction during a conference call in first-quarter 2011, Chesapeake CEO Aubrey McClendon was characteristically ebullient: “We are going to do for oil what we have done for natural gas,” he declared. ■

4. Exponential, hyperbolic and harmonic declines.

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**Source:** Fekete Associates, Calgary