Domestic Gas Resource Plays, Exploration Boom or Folly?

By Dr. Matthew Carr, PG

January 16, 2010

In recent years there has been an increasing focus on Shale Gas Resources Plays in the United States. Several Companies (Common Recourses for one) have completely divested their traditional oil and gas projects, to focus solely on theses gas resource plays. Initially, the definition of a Shale Gas Resource must be defined. Here we consider any play that focuses on a nontraditional reservoir (usually shale), to produce natural gas in a nontraditional trap setting as a "Gas Resource" play. There have been many years of work that has pointed to a large amount of natural gas being associated with several well known source rocks (i.e. in the Haynesville Shale). There is no disputing the likely presence of the gas; after all it is what sourced many traditional reservoirs throughout the domestic US. However there is significant debate over the produceability of these nontraditional reservoirs. Recent controversy led by Art Berman and others has used publically available data to examine the actual production history and predict the ultimate recoverable reserves in several of the Gas Resource plays. From 2008 to 2009 the US booked a 30% increase in natural gas reserves. The problem with that is that is not gas in place that number represents actual recoverable reserves. As pointed out by Dave Cohen article in June of 2009, this is what is "technically recoverable". The economics of recovery is quite a different argument. Recent work by Berman and others (see Appendix) dramatically calls the economic recovery of these shale gas plays into question. The result is a highly speculative and volatile market in Natural Gas, a glut of gas resource plays for investors to potentially buy into, all with questionable science backing the entire play. There are significant physical limitations to the produceability of many of the Resource Play main targets, coupled with infinitesimal knowledge of the flow capabilities of these lithologies. Black Hawk Energy's position is to avoid the nontraditional gas play for more conventional oil and gas plays.

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APPENDIX

Facts are stubborn things: Arthur E. Berman November 2009

Several rebuttals to Lynn Pittinger's and my position that shale gas reserves may be overstated have surfaced in recent weeks. This development is welcomed and positive because it elevates the important discussion of shale reserves and economics to a higher level of public awareness and dialogue. Although these rebuttals have been directed at me, I am not the only one with doubts. Ben Dell at Bernstein Research has published several reports recently that express similar, independently determined concerns about the cost, efficiency and reserves of shale plays. These doubts are shared among many petroleum industry scientists and financial analysts despite the enthusiasm for these plays by large public companies.

Critics of our position on shale gas plays have focused on methods of decline-curve analysis, and the projections of estimated ultimate recovery (EUR) that result. The problem with this debate from all sides is that we are uncertain about how to apply decline models to newer shale plays because there is insufficient production history to satisfy all of our questions. I will, therefore, focus on some stubborn facts about Barnett Shale cumulative production and approaches to play development.

Major operators claim that their average Barnett EUR will reach 2.2-3.3 Bcf/well. Figure 1 shows that those levels of EUR are unlikely to occur in an economically meaningful timeframe based on cumulative production to date. Figure 2 shows that well performance has been erratic since operators began drilling horizontal wells, though the trend has been improving slightly in recent years. This is probably due to drilling outside of what are now known to be the core areas. The "manufacturing" paradigm that is prevalent in shale plays has led many companies to assume that all areas in the Barnett Shale and other plays are uniformly attractive.

Shale plays typically begin with a leasing frenzy whereby major players accumulate hundreds of thousands of acres, often at astronomical bonus prices. Next, a drilling campaign ensues driven more by lease expiration schedules—typically in the 3-year range—than by science. Only after considerable capital has been destroyed in this manner are the core areas recognized. This "Braille method" is completely opposite to the customary approach to E&P projects, where a cautious approach based on science is used to high-grade focus areas.

The methods used to obtain decline rates and reserve estimates for shale plays presented in this column employ best practices in the petroleum industry. Yet a group of professionals believe that some shale plays are exceptions to the methods of decline-curve analysis established by peer-reviewed papers published by the Society of Petroleum Engineers (SPE). It does not seem logical that type-curve methods should be more reliable than individual well decline-curve analysis. If the pattern of well decline is empirically exponential, it makes no sense that it should be treated as hyperbolic for conceptual reasons or because of a preference based on production from higher permeability reservoirs that are not comparable to those in the Barnett or other recent shale gas plays.

We recognize that it may take many years before true pseudo-steady-state flow is reached. But in the Barnett, decline trends are well developed in thousands of wells, and we must forecast reserves based on those trends, and not on some future, model-driven expectation of flattening decline rates.

Let me be clear. We do not dispute the volume of gas *resources* claimed by operators. We do question the *reserves* that, by definition, must be commercial on a full-cycle economic basis.

The time has come for the companies that operate in the shale plays to show the data that supports their optimistic forecasts for natural gas supply in the US. The economic viability of shale gas is a serious issue with profound implications for capital investment, alternate energy research funding and national policy. To simply say that those that have doubts about shale plays are wrong will no longer satisfy the many intelligent people who follow this debate.

Data provided courtesy of IHS Inc. However, the analysis and opinions expressed here are solely those of the authors and do not represent those of IHS or any other organization.

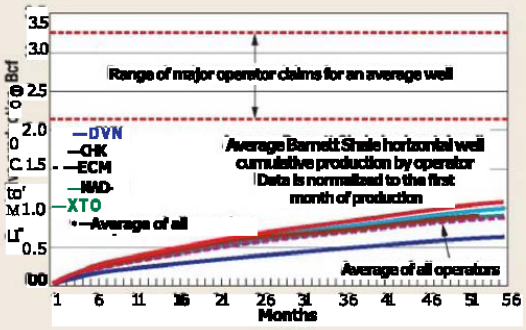

Fig. 1. Average cumulative production per well by operator.

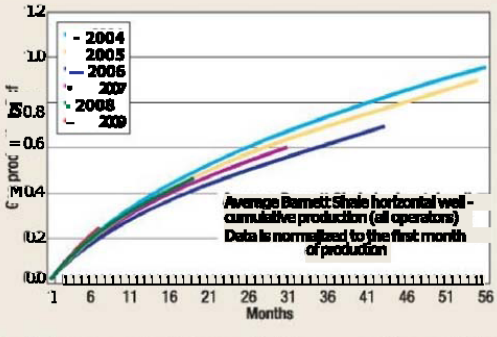

Fig. 2. Average cumulative production per well by completion year.

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A shale gas boom?

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by ASPO-USA

But I think you also have to be impressed by the credulity of the people who invested and the desperation and almost the laziness—the lack of due diligence of the people who pumped their money in. I mean, when it comes right down to it, people really don't know much about this world, and they're looking for some kind of Virgil to give them a tour through it. And they don't really do much investigating, and they just—they defer far more to someone like [Madoff] than they would in circumstances where the stakes are much lower
—David Margolick, a writer for Vanity Fair, speaking on NPR about Bernie Madoff's victims

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With the release of the Potential Gas Committee's 2008 year end assessment last week, there was a fresh wave of enthusiasm for replacing oil or coal with natural gas. The PGC, led by Dr. John B. Curtis of the Colorado School of Mines, found a lot of new resources in their reevaluation of potential shale plays.

The Potential Gas Committee (PGC) today released the results of its latest biennial assessment of the nation's natural gas resources, which indicates that the United States possesses a total resource base of 1,836 trillion cubic feet (Tcf). This is the

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highest resource evaluation in the Committee's 44-year history. Most of the increase from the previous assessment arose from reevaluation of shale-gas plays in the Appalachian basin and in the Mid-Continent, Gulf Coast and Rocky Mountain areas…

The Potential Gas Committee reports its gas resource assessments biennially in three categories of decreasing certainty—*Probable, Possible* and *Speculative*. For each category, a *minimum, most likely* and*maximum* volume is assessed for each of 89 geological provinces in the Lower 48 States and Alaska. The *mean* values shown in Table 1 below were calculated by statistical aggregation of the minimum, most likely and maximum traditional values for each resource category…

[My note: see the link above to view Table 1. Figure 1 shows the major U.S. shale basins.]

Figure 1 — The major shale plays in the United States, from a report by Navigant

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Consulting, Inc. for the Clean Skies Foundation sponsored by Chesapeake Energy Corp. (CHK). Some of the biggies in or starting development include the Antrim (#1), Barnett (#3), the Haynesville (#10), the Marcellus (#13) and the Bakken (#2).

If you add up the mean values for Traditional Gas Resources, which includes shale gas, and Coal Bed Methane, you get the 1,836 Tcf of potential resources. If you throw in the EIA's proved reserves, the total resources are 2,074 Tcf in the Lower 48 and Alaska. Curtis explained that his tally represents the 'technically recoverable' gas resource potential of the United States. At current consumption rates, the new total represents about 100 years of supply. If speculative resources (500 Tcf) are excluded, we would still have about 75 years of supply.

Suffice it to say that there is little reason to doubt that the *potential* natural gas resource base in the United States is very large. The hidden problem with such estimates relates to whether the gas is economic to produce, an issue which is outside the PGC's purview.

Let us assume for now that all the gas (2,074 Tcf) that might be there is actually there. Let's further assume that it is indeed technically recoverable and economic to produce at a "reasonable" price, which I will leave undefined. What would we do with the gas?

We have two energy problems in the medium to long term, climate change and peak oil. (In the *very* long term, all bets are off.) Consequently, shale gas has been proposed as a temporary (a few decades) solution to both. We can—

- use natural gas to replace liquid fuels in transportation, especially as a replacement for diesel in long-haul trucking. This is the (T. Boone) Pickens Plan, which is currently dead in the water. Pickens expressed hisexcitement about the PGC reports, saying that "the 2,074 trillion cubic feet of domestic natural gas reserves cited in the study is the equivalent of nearly 350 billion barrels of oil, about the same as Saudi Arabia's oil reserves." Pickens is selling his plan—he knows better than to spout nonsense like this. ASPO-USA commentator Tom Standing did an excellent job of analyzing the energy density issues and practicalities (e.g. compressed natural gas versus liquefied natural gas) of replacing diesel with gas. It would take decades build out the supply chain (e.g. swap petroleum gas stations for natural gas stations). Robert Rapier also wrote an analysis worth reading on this subject.

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- use natural gas to replace coal in electricity generation to reduce CO_2 emissions. Dr. Joseph Romm of the influential Center for American Progress is already calling the potential shale gas play a game-changer. The imminently practical idea is to ramp up under-utilized natural gas power generation capacity to replace base-load coal. Geoffrey Styles' analysis Shale Gas and Climate Change provides an excellent overview, so I won't repeat the details here. Even if you don't believe we are going to make an 80% reduction in our emissions by 2050—I don't believe it—official policy is to act as though we are going to do so. We now have the makings of a *de facto* moratorium on coal (and here). We seem to be unwilling to build new nuclear capacity. It is theoretically possible for wind to provide 20% of our electricity by 2030, but there are many practical, economic & political barriers to success. Thus it would behoove us to switch to natural gas at large-scales if we want to maintain a functioning electricity grid 10-15 years from now. This is my current view, but the political winds could change quickly as the Great Recession grinds on.

If we are at the beginning of a long term shale gas boom, it is clear we can put the gas to good use. But that's a big IF. Before we make a policy commitment to a natural gas future, we must be certain the gas will be there.

Let's return to the real world, a messy place where some potential gas resources may not exist, or may not be economic to produce. Things get complicated here, but don't they always?

Shale Gas Economics

At first glance, increased shale gas production (*Figure 2*) looks like a textbook case of resource economics. A "new" technology (horizontal drilling & hydraulic fracturing) combined with rising price (*Figure 1*) boosts recoverable reserves over time.

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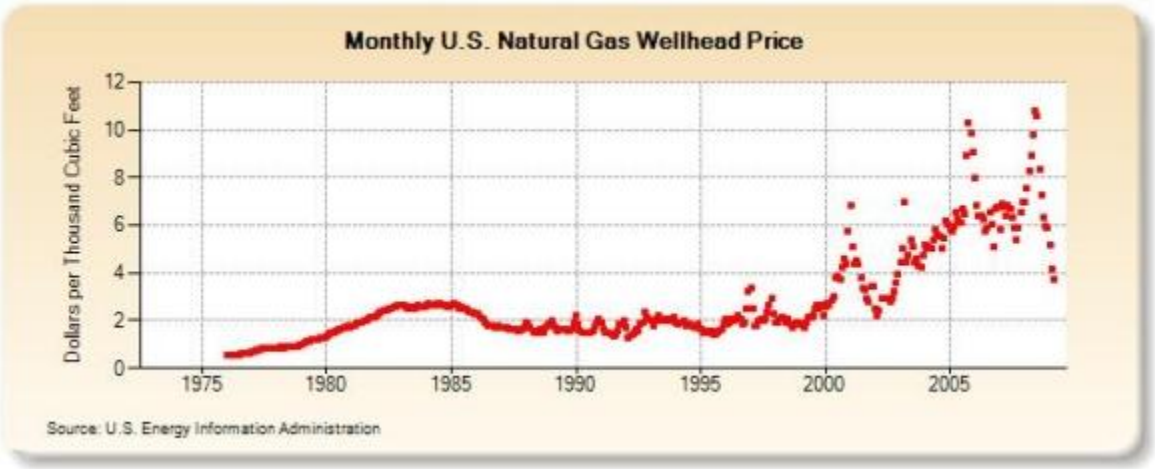

Figure 1 — The history of natural gas wellhead prices since the 1970s, from the EIA. Volatile prices have increased since about 2002, but have fallen lately during the downturn.

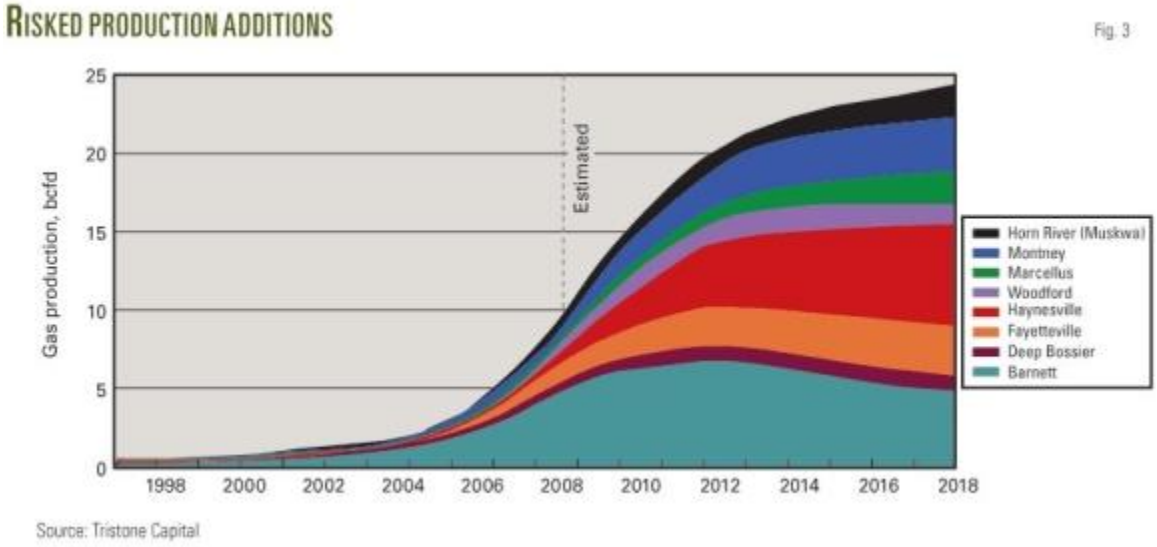

Figure 2 — Increased shale gas production with a risked estimate out to 2018, from a Tristone Capital study (October, 2008) described in the Oil & Gas Journal's Study analyzes nine US, Canada shale gas plays. These are risked production additions — "the study expects companies ultimately to recover from these resources 261 Tcf of gas, based on various risk factors applied and a long-term average gas price of $8.50/MMbtu. Without the risk factors, Tristone Capital says these shales have a 743-Tcf recovery potential." The Horn River and Montney shales are in Canada, so they don't appear in Figure 1.

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Tristone Capital's future production estimate depends on a long-term average price of $8.50/Mcf (per thousand cubic feet abbreviated as Mcf, equivalent to million British Thermal Units, abbreviated as MMbtu). The required price is well over the 15-year average of ~$5.50/Mcf.

What average natural gas wellhead price allows the shale boom to continue? Shale gas economics is a contentious issue. One camp believes that shale gas is economic at—and will keep future prices in—the $5-6/Mcf range. I'll call these analysts *the optimists*.

The other camp believes the marginal cost of shale gas production is $7-8/Mcf, and perhaps much higher depending on the shale play. These are *the pessimists*. Let's break down the arguments.

Barclays Capital stock analyst Tom Driscoll is an optimist. On May 27, 2009, Platts quoted Driscoll as saying—

"Conventional gas is being displaced by unconventional gas," Driscoll said and it may take "20 years for natural gas prices to recover."

"The emergence of low-cost unconventional, and especially shale gas, resources may lead to lower than expected natural gas prices for the next five to 10 years," Driscoll said. "Shale — along with other low-cost unconventional gas — could provide 75% to 90% of new gas supply over the next several years and set the marginal cost of new supply."

Despite the nearly 50% cut in rig counts since their peak in the fall of 2008, Driscoll estimates that fourth-quarter 2009 gas production numbers will show no decline from fourth-quarter 2008 numbers…

He said he estimated the market will average 4 Bcf/d worth of oversupply this year and 3 Bcf/d worth of excess gas in 2010.

Driscoll said the more productive horizontal rigs are profitable at prices "materially below" $6/Mcf, which just keeps gas flooding into the market even as cash prices plummet.

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[My note: Driscoll and others also project that shale gas may provide up to 40% of U.S. supply by 2013.]

This is a very bullish forecast. Despite reduced rig counts, and despite the likelihood that we will have low or average gas prices over the next few years due to the recession and oversupply, the market share of shale gas grows and grows. This forecast looks like a high-wire act that defies not only gravity, but also the laws of supply & demand. One wonders what the *minimum price* is that makes shale gas unprofitable. $4.50/Mcf? $3.50/Mcf?

Another optimist, Ziff Energy, tells us how much gas is produced from shale now.

Ziff Energy Group forecasts unconventional gas production will supply 53% of US gas needs by 2020, up from 30% in 2000.

Ziff Energy's Shale Gas Outlook to 2020 says shale gas production in 2008 was more than 5 Bcfd (8% of North American gas production), with 70% coming from the Barnett shale in the Fort Worth basin of Texas.

In the future, the report sees increased gas coming from the Barnett, Fayetteville, and Woodford shales as well as many other plays such as the Haynesville, Marcellus, Horn River, Utica, and Gothic. The report expects in 2020 that North America will produce 87 Bcfd compared with 70 Bcfd in 2000.

[My note: "Bcf" stands for billion cubic feet and "Bdfd" is the daily rate. U.S. dry gas production was 20.56 Tcf in 2008. The production rate was 56.33 Bcfd. The U.S. consumes more gas than it produces, getting the rest from Canadian and liquefied natural gas (LNG) imports. Conventional gas production peaked in the 1970's in the United States. New supply from unconventional tight gas (and some coal-bed methane), along with imports, filled the supply/demand gap. As *Figure 2* shows, shale gas is a johnny-come-lately on the gas scene.]

The biggest booster is the man who is selling shale gas—Chesapeake CEO Aubrey McClendon.

At Chesapeake Energy's recent shareholder's meeting, Chairman and CEO Aubrey McClendon suggested that the increased use of natural gas would be a way to help the U.S. stop indirectly funding nations that are "declared enemies" and would benefit the

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environment as well. McClendon said the lack of availability of natural-gas-powered cars in the U.S. is "the most frustrating part of my existence today" and pointed out that General Motors manufactures 12 car models throughout the world that come off of the assembly line ready to run on natural gas, yet there are no such models in the U.S.

McClendon knows how to sing the right notes, but I thought his "most frustrating part of my existence" statement is a bit overdone. What do the pessimists—they would prefer to be called realists—say about all this? And how would optimists respond?

Art Berman, a Houston geologist and columnist at World Oil Magazine, does not believe most shale gas wells are economic unless operator costs go down, gas prices rise sharply, and high average prices are sustained. Talking about the Haynesville in A Long Recovery for Natural Gas Prices, Berman says—

Drilling and completion costs [in the Haynesville] vary from $7.5 to $10.5 million per well. The marginal cost for operators to find and develop natural gas reserves is $7 to 8/Mcf, and current netback prices in the play are less than $3/Mcf. The threshold netback gas price for a better-than-average 5.5 Bcf well to break even is $7/Mcf at NPV10 (Bodell and Pittinger, in press). For companies that have favorable hedge positions, realized gas prices for 2009 will be as high as $6.50/Mcf and $6.00/Mcf for 2010. This means that the play is marginally commercial today for operators with favorable hedge positions, but not commercial based on cost and price fundamentals.

Berman's argument is based on current (and likely future) gas prices, a minimum ultimately recoverable per well, and "all-in" costs of about $7.50/Mcf, not on the impressive initial well flow rates often reported in *Rigzone*. At current prices, the netback of $3.25/Mcf barely covers operating costs, so no Haynesville well is economic and rates and reserves simply do not matter. Berman's analysis of the Barnett is just as bad—

Shale gas is not commercial at any "reasonable" price because the costs are too high—I once calculated that at ~$12/Mcf only slightly more than 50% of Barnett Shale wells would break even or more money. I am now working on a re-evaluation of the Barnett Shale 11,500 wells later. The average per-well EUR is about 0.6 Bcf—pathetic! The cost is staggering—more than $30 billion and most of it hopelessly non-commercial…

[My note: quoted from an e-mail from Berman. 0.6 Bcf includes vertical wells, about 1/3 of the total drilling in the Barnett play. The average estimated ultimately recoverable (EUR, reserves) for horizontal wells is ~0.75 Bcf.]

But what about our classic case of resource economics? Prices rose (*Figure 1*) and shale gas production increased (*Figure 2*). That would seem to belie Berman's pessimism—the proof is in the pudding. What's the problem?

The wrench in the works is that operators appear to have *lost money* producing shale gas. McClendon recently stated that "we believe that Chesapeake's strong financial condition and extensive hedges provide us with … [the] flexibility to make prudent natural gas revenue maximization choices." No doubt Chesapeake will try to maximize their revenue, but do they have a strong financial condition? Berman says No—

I have worked through the 10-Ks of most of the major shale players (Chesapeake, Petrohawk, Range Resources, etc.)—they're all taking a bath financially but put on a brave face, and have huge debt. As long as their stock price is good, the executives get rich so why do they care? The analyst community is so naive about true costs that they believe the propaganda.

[My note: Chesapeake has 14.4 billion in senior debt and their stock price is faring badly. "CEO Aubrey McClendon has come under some well-deserved fire for his high compensation in the face of poor results and a declining stock price. He was paid a one-time $75 million bonus at the end of 2008—suspicious timing given that the stock had lost most of its value in recent months and Mr. McClendon had lost his entire stake in the company to margin calls."]

Most shale operators work on borrowed capital—who is going to lend that kind of money [~$150 billion for the ~30,000 wells required to quadruple shale gas production] to companies like HK [Petrohawk] and CHK [Chesapeake] that are already in debt up to their eyeballs?

[My note: The 10k is a document filed with the SEC that contains ... the same financial statements the annual report does in a more detailed form.]

I entirely agree with Berman's take on things here. There's no dearth of clueless analysts—I've read or listened to more than a few. Berman's deeper point about

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propaganda is also right on the mark. In the Age of Hype, the Ponzi Scheme and the Swindle, why wouldn't some natural gas companies want to get in on the deal?

Other analysts like Ben Dell, a senior energy analyst at Bernstein Research in New York, are suspicious about corporate reporting of returns on shale wells.

In a March 27 research note, [Dell] notes "a growing discrepancy between the internal rates of return (IRR) presented in corporate presentations and company reported ROACE (return on average capital employed)… For example, in many plays companies claim to generate IRR's above 100% at $7.50/mcf gas or claim that their production is economical even at $2-3/mcf gas prices, but at the same time report 6-7% ROACE at a corporate level over the last 3 years, when the average gas price was $7.50/mcf."

Titled "Why the Haynesville Won't Work…at $4, $5, or $6/mcf gas", Dell posits that companies are overstating production, understating costs, or there is a terminology gap at work. For example, a producer could say the IP rate of a well (Initial Production) is 8 mmcf/d (million cubic feet per day). But was that a 30 day average, as is normal, or was it a 12 hour average just after coming online. These HD wells can decline in production so rapidly sometimes that for stock promotion purposes, companies issue figures that may have been correct for a short time, but have no context and are not really "best practices" type numbers.

Dell also questions if the all in costs of a well are being amortized properly into the economics that appear in a company's press release. If the cash operating cost of a well is $3/mcf, which is the number that appears in a release that does not include the $4-7 million it cost to buy the land and drill the hole - costs that Dell suggests basically doubles the breakeven level of the well to $6/mcf. And to get an acceptable return - even to generate enough cash to drill the next well - would be $8/mcf.

Dell's analysis and Berman's are the same in all the essentials. Let's sum up the situation so far—

- Shale gas operators are up to their eyeballs in debt. They would need to borrow vast sums of money—Berman suggests it would take ~30,000 wells and ~$150 billion—to get shale gas up to 40% of total U.S. dry gas production by 2013.

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- Shale gas operators can't possibly make money at current natural gas prices, or medium-term future prices if these are close to the 15-year average (~$5.50/Mcf).

The situation is actually worse than our summary indicates. Shale gas wells have very steep decline rates. Consider the Griffith #1 well in the Haynesville as reported at *Rigzone*.

The Griffith #1 well located in Desoto Parish, Louisiana was completed and brought online in January 2009. The exact reading for total gas produced from the Haynesville shale [Griffith #1] and shipped to market through March 10, 2009 is reported at 568,856 Mcf or .568 Bcf…

The Haynesville Shale play is a new play less than one year old and there is limited data to work with to determine the decline rate for Haynesville Shale wells. [Mainland Resources, Inc.] believes that the recoverable reserves for the Griffith well may ultimately be from 7.5 Bcf to 15.81 Bcf. The 15.81 Bcf rate was determined by a reserve report for the Griffith #1 done by T.W. McQuire & Associates, Inc., prepared pursuant to U.S. Securities legislation. The ultimate recovery was determined by using a type curve that uses 80% decline for the first year, followed by 30% decline for the second year, 15% decline for the third year, and then a 10% decline over the remaining expected life of the well. This decline was derived from the Deutsche Bank report issued in 7/08 based on a study of various shale plays.

[My note: The quoted .568 Bcf is over the first 40 days of operation. Using a type curve to figure declines in the Haynesville may be misleading. Berman's observed decline rates for the Barnett Shale are as follows:

Year 1: 65%;
Year 2: 53%;
Year 3: 23%;
Year 4: 21%;
Year 5: 20%;
Year 6: 17%;

Year 7: 21%

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Berman notes that "there is no empirical justification to lower terminal decline rates to 10%/year, and there is no factual evidence for the declines used in Years 2 & 3 by Deutsche Bank. This is what happens when bankers try to do petroleum engineering and geology. They have used a model to get these declines but have not bothered to calibrate it against the only shale play in the world with enough production history to it compare to."]

The Griffith #1 well may or may not turn out to be a winner, but the stated reserves (7.5-15.8 Bcf) seem inordinately large for a shale gas well. Steep declines several years into production, even when there is a high initial flow rate, largely determine what the well reserves will be, which Berman calculated as only 0.6 Bcf *on average* for the 11,500 wells drilled in the Barnett Shale.

And we only hear about the successful wells, the *creme de la creme*. It would be unusual to find a story at *Rigzone* that reads like this—

Desoto Parish, Louisiana — March 13, 2010

Mainland Resources, Inc. announced today that their Bogus #2 well in the Haynesville showed weak flows in the first few weeks after production began … Spokesman John Q. Smith said "we probably won't get 0.3 Bcf out of the damn thing… We'll never get our money back." He called the results "very disappointing." … Smith concluded that "drilling this well was a complete waste of time and money."

When we consider disappointing wells and high decline rates in successful wells, it is clear that getting shale gas up to 40% of U.S. production by 2013 is not only very expensive—$7.5-10.5 million for drilling & completion according to Berman—but also requires poking a lot of very expensive holes in the ground.

One problem with analysts like Tom Driscoll, who is a *stock analyst* working for *Barclays*, which is a *bank*, is that they remember how to add but they've "forgotten" how to subtract. This applies straightforwardly to the shale gas play. The usual human bias, as evidenced in *Rigzone* stories, is to play up the successes and ignore the failures, as Nassim Taleb pointed out in his book Fooled By Randomness. We see the single entrepreneur who succeeded on TV, but we never hear about the 10,000 who failed. This introduces a significant skew into the data being examined.

I do not mean to make a sweeping generalization. Paul Horsnell, who is an oil market analyst at *Barclays*, knows what he's talking about.

The optimists' response to all this bad news is summed up by Keith Shaefer's Natural Gas: Costs go down as learning curve goes up. To give the opposition equal time, I will quote it at length.

Operating costs are still coming down in North American natural gas and oil plays. This isn't showing up as reduced all-in costs on the financial statements of these energy producers just yet, but it will.

Costs are lowering for two reasons. One is demand destruction, which has cut in half the number of rigs drilling for oil and gas in North America. This has meant that rig rates have also dropped—energy executives are saying they see 20%-35% cost reductions year over year. Lower drilling costs have an obvious impact on profitability.

The second is that companies in both the US and Canada are figuring out how to properly frac these new unconventional gas plays—both tight gas and shale gas…

Calgary based securities firm Tristone Capital says wells in the Montney gas play on the BC-Alberta border are now 8-10 mmcf/d [million cubic feet], about twice what they were when the play first started.

… the energy producers are learning how to frac these plays much better, using special mixes of chemicals and water to get the most oil or gas out of these new, very tight reservoirs. It can sometimes take some expensive trial and error on how to get that frac formula right.

Tristone estimates the average break even level of these new shale plays is now hovering around $5/mcf, with the best plays already at $4, and as the learning curve goes up, the cost curve will continue to go down, taking the break even price for natural gas production down with it.

What will likely mask these costs on the financial statements of these companies is the huge land acquisition costs these companies had to pay for these unconventional plays. As an example, British Columbia in Canada has sold their land rights at an average $680/hectare (1 hectare = 2.5 acres) compared to $3511 per hectare over the

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same time frame in 2008 — and B.C. has the new Horn River Basin in the north and part of the Montney gas play along the Alberta border. Both 2007 and 2008 saw huge land cost increases across North America as companies rushed in to buy up acreage…

Until some of these high land costs are amortized out, don't expect to see the "accounting" cost of finding a barrel of oil [gas] — usually shown as DD&A - Depletion, Depreciation and Amortization—on the balance sheet, to go down much, even though "real" costs are dropping a lot.

So when people ask "Where is all the cheap gas?", it's here, and it's getting cheaper by the month, but it might not show up in the companies' financial statements for awhile.

It appears Tritone has changed its tune, revising its $/Mcf from $8.50 (*Figure 2*) to $5. This story says that 1) previous "all-in" costs of $7.50 or more were due to expensive land acquisition; 2) oilfield expenses are declining as rig rates go down; and 3) operators are ascending the learning curve for shale drilling, which lowers costs and boosts reserves & flows. These factors imply that fewer wells will produce more gas due to "more productive horizontal rigs," as Driscoll maintains.

Berman's response?

If shale operators cannot substantially reduce their costs, I doubt that most of them can survive a year or so more of low prices (Barclay's "low camp" $5-6/Mcf) because their marginal cost of production is $7-8/Mcf, much less find $150 billion or so for more unprofitable drilling. I believe that the cost of services will escalate at a higher rate than cost, and will never drop to meet low price (except for possibly too brief a period for most operators to take advantage of).

Actually the frac costs keep increasing because operators are now commonly using 10-12-stage fracs that cost millions. Rates are higher but at what cost and for how long? The key here is that the extra cost may only accomplish a rate acceleration and not an increase in reserves. In the Barnett Shale, the average horizontally drilled and fractured wells only have ~25% more reserves than vertical wells but 3x the cost! This talk about lowering operating cost and increasing reserves is more propaganda, and most cost benefit is more than negatively compensated by more interest expense on debt.

Let's sum up.

A Shale Gas Boom?

Will we have a shale gas boom? I've described the contentious argument among those who follow the natural gas industry. Generally, my sympathy lies with skeptics like Art Berman. As someone who has written extensively about peak oil, I've encountered the human proclivity to hype a situation far beyond any semblance to reality time and time again—the Jack #2 discovery in the Gulf of Mexico comes to mind.

Nevertheless, I'm going to say the jury is still out on this one. That's not a cop-out, because the verdict will be in very soon, certainly within the next few years. Art Berman is making specific predictions, just as Driscoll, Shaefer, and Ziff Energy do. Berman surmises that natural gas prices may stay below or in their average range (~$5.50) for a few years based on a host of new factors that include greater availability of tight gas from the Rockies and increased LNG imports. If Berman is right, we will *not* see large increases in shale gas production through 2011, or some companies will go belly up, or both.

Promoters like T. Boone Pickens and Aubrey McClendon have offered us a Golden Vision of a future powered by natural gas. Their forecasts assume a shale boom that will last for decades. But we shouldn't count our chickens before they're hatched. It costs us very little to take a wait & see attitude on the shale gas boom—we'll know soon enough if it's for real.

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