***From:*** [redacted]
***Sent:*** Thursday, April 28, 2011 4:14 PM
***To:*** [redacted]
***Subject:*** RE: EIA Nat Gas Conference 2011

A conversation to be continued. No details right now – just a few overall points:

1. The technological phase vs. the depletion phase is almost a definitional issue to me. There's a time in many economic processes when technological advances (and economies of scale) outweigh the increasing costs of greater production. And a time when the opposite is true. It is an empirical question when the tide turns. I think we disagree on our guess as to whether we've reached that point already or, if not, how much more there is to go. Legitimate issue, subject in theory to empirical test – but probably not in practice. In any case, the time spent in the technological phase doesn't depend on the novelty of the invention. Fracing and horizontal drilling are very old. But pretty clearly, sometime in the mid-2000's the two came together in a way that drastically changed the attractiveness of using them for shale. In addition, these aren't necessarily technological innovations. Henry Ford's assembly line was more about business process than anything else. Sam Insull's use of economies of scale wasn't only technological. I have no idea whether business process innovation has been at work here … but it may well have been. Nor are small tweaks to be scoffed at. It is easy to imagine cases where learning to tweak the micro geology could make huge differences. Think of using tungsten in light bulbs …

2. For many purposes, the question isn't what most companies do, but what the best (most efficient) ones do. That will set a competitive standard that others will have to meet (more or less) or perish.

3. My point on the "Where do you put it?" and "What about Qatar?" questions is that if we don't get volume increases in our own production, it may because we've been undercut, not because it's too costly. From a customer standpoint, that makes all the difference. In one case, I get all the gas I want at a low price, and I don't really care what happened to the US producers. In the other, I'm paying a lot more because we couldn't meet our volume projections.

4. The flexibility of production argument doesn't depend on collusion. When the price goes down, some companies see they can't make money and cut back. When the price goes up, those companies come back and others increase their production. Now, if they have to drill to meet interest payments or for other reasons, that dampens the effect. But, given the initial decline rates, you'd almost have to see a decline in volatility over fairly short (few months?) time frames, compared to what would have been there otherwise. Now, that might happen around a high price or a low price, but still volatility would go down. As an example, I can imagine that some companies would begin drilling seasonally. If you complete wells so that you got your big initial slug of production in the

winter or summer (rather than spring or fall), you could make more money off it.  I don't know if that's happening, but it wouldn't surprise me.

[redacted]

***From:*** [redacted]
***Sent:*** Thursday, April 28, 2011 1:47 PM
***To:*** [redacted]
***Subject:*** RE: EIA Nat Gas Conference 2011

[redacted]

Thanks for the extensive response; it's very informative. I think the one big assumption that you are making that could undermine the rest of your argument is that the technology improvements lead to increased efficiency and reduced cost over time. I think this is true, but the real question is to what extent?
I wrote a few thoughts/responses in red below.

[redacted]

***From:*** [redacted]
***Sent:*** Thursday, April 28, 2011 12:31 PM
***To:*** [redacted]
***Subject:*** RE: EIA Nat Gas Conference 2011

No need for thanks - it was a great question, and it pretty well summarized a fairly large number of similar concerns.  And I completely agree that discussion is the best way to understanding.

In that spirit, my own feeling about this is roughly as follows:

1. Shale gas is largely a technology play, so far, not a depletion one. In the technology phase, costs will generally decline because the savings from improved techniques and knowledge are larger than the increasing costs from having gotten all the good stuff. After that, costs will increase until and unless a new technological wave hits. The gas industry already went through one round of all this – the so-called gas bubble that kept prices far lower than the industry wanted from 1983 through 1999, largely because of things like 4D seismic, etc. (Of course, both the down and the up can be perturbed by short-term shortages or gluts in key inputs). At some point, the cycle will presumably turn. Conceivably, it might already have done so. But probably not. There's just too much still to be figured out, about the geology, about fracing and other drilling techniques, etc. And the depletion phase, when it comes, is likely to be gentler in the past, simply because the overall supply curve looks much flatter than before. (Of course, that might not prove out in practice, but that's what it looks like right now.) Yes, high volume fracing and horizontal drilling combined with in-hole tools to determine the best sections of wells to frac has allowed this play to proceed. Are these technologies really that new? Not really; just a change in scale and application with some fine tweaking; in light of variability within and between plays, evolving regulations, and the move to hold off on drilling to be resumed at a later date might overwhelm cost/efficiency improvements . I also think the overall supply curve could be more volatile given the financial footing of the companies and low prices; prices rise in response to dropping demand- companies drill-supply increases, price drops-companies wait… not sure how that would actually work out in real time.

2. On the cost side – as long as it's a technology play, the variable cost of producing gas from an average well will keep coming down (BIG assumption, in my opinion). In theory (and in practice, I would guess), that leads to four kinds of costs that the operator has to consider.

a. For wells that are already flowing gas, the decision is the marginal cost of producing more gas. Pretty low, probably not going to be affected by any likely low price. And rapid decline curves mean it's not so important, since falling production comes naturally. I think the decision with regards to marginal cost really relates more so to servicing debt with production (better to get some return to pay interest on debt now rather than nothing) than it does the marginal cost of the well. Many of these operators don't have a much of a choice, even if the marginal costs of production aren't justified by current well-head prices.

b. For re-fracing a well or drilling a new well, the decision will be based on the variable costs of the new job. That will be hit at some price point – what that point is the subject of some mystery.. But for now that price point will be artificially low for at least two reasons - the presence of liquids in the production stream, and the need to drill something to retain leases.Agreed.

c. Existing companies would like to recover their all-in costs, including a lot of sunk costs like lease payments. But that should not drive many short-term drilling decisions, because companies (and their creditors) are better off getting something than nothing. It is quite likely that many of these companies will go bankrupt, or be forced to sell a lot of stuff at a loss. Effectively, that means someone else buys up the sunk-cost assets at a fraction on the dollar. Then they have pretty clean financial sheets and can go forward (until, perhaps, the same trap gets them). I agree, but I have to wonder how the better-situated companies will be able to compete with lower-priced sources of gas and gas that is already going to be coming to market from shale, even if they are getting a bargain on acquiring the positions of the companies that go under.

3. The problem for existing companies in the technology phase is that there's relentless pressure driving down marginal costs, but nothing that retrieves previously sunk costs (One of the results of the pressure to drive down costs is reduced drilling time, which can have a negative impact on decisions regarding cementing practice, which I believe is linked to many of the cases of contamination, so while efficiency may improve, this pressure to increase efficiency may have an unintended consequence of poorer environmental performance, which could lead to more regulation and public resistance). So you put a tremendous premium on being ahead of your rivals technologically, having a pretty fair volume and having been lucky about how much cost you sank. For instance, leases acquired during the first half of 2008 will probably never pay off – and too many of them will crater whole companies. But all this is familiar from other industries, especially perhaps IT. And the end result is - you're right, it doesn't make much sense for a lot of companies to be in this business – but they're stuck with the decisions they've already made. And to the extent that you're right, companies that enter or expand now should have considerably lower fixed costs that make the deal look more attractive (although, they're fairly likely to get caught up in the same maelstrom, just at a lower level – certainly there's a fair amount of irrational exuberance out there.) How much more attractive is the question. If these reductions in marginal costs aren't achieved, even with lower fixed costs upon entrance or expansion, I'm not sure it will make sense to pursue drilling wells if the cost per well doesn't go down.

4. To the extent that all this is roughly right, the demand side presents two potential challenges. One is that demand will grow too quickly, create a lot of bottlenecks on the gas side, and become self-limiting. Personally, I think this is relatively unlikely because of the other challenge – where is the market coming from? What we've seen so far is that gas can drive out Eastern coal, especially in the southeast for power generation. A significant market, but not huge. And there are some inroads in the Northeast as well. But

a. It's by no means clear that gas will actually win that competition much more than it's already doing. That is, right now Eastern coal and gas are pretty comparably priced, and there's no special reason to see either one changing its relative position very much. So maybe some growth potential, especially if coal exports are stronger than expected. But not a whole lot. agree

b. It will be much harder for gas to win against Western coal. yes Even if gas could match the delivered prices of those coals (which it seldom can right now) well over half of the delivered costs for those coals come from transportation – and the railroads are likely to be ruthless about maintaining market share by cutting rates, (but only) if they have to be.

c. Beyond that, where's the increased demand for gas? In displacing fuel oil? Quite likely. Not a large market. In transportation? Perhaps – but it's a long way from here to there. Given the huge cost differentials between gas and oil (even if gas prices go up quite a bit), you would think that something should start happening. But it hasn't yet and it's hard to see how it happens very fast. Agreed; without substantial increased demand, I'm not sure how the equation will balance out to allow anyone to make money as these companies either lose money on leases by not drilling the new wells they are obligated to drill (unlikely), or by continuing drilling to continue to tread water (better to produce at a lost in the hopes of better pricing than to lose position and money paid for leases)

5. So my question for the gas industry is at least as likely to be "Where are you going to send all this stuff?" as anything else. Agreed; while all the hype about gas sounds great, it doesn't matter if we don't figure out a way to use all of it to keep demand in pace with supply.

6. I couldn't see [redacted]'s slides from where I was sitting, so I don't know about the efficiency point you make. What I would say is that a lot of people who ought to know think we're still on the learning curve with a fair way to go … I think this is an assumption that I have yet to see validated. Some companies will do a better job at reducing per-well costs than others, but is there enough savings to be had to really drive a substantial drop in the cost to drill and produce the gas? I don't know, but based on the geologic variability, stop-and-go drilling, and potential changes in regulation (notice no more water to treatment plants in PA?), I would say that these technology-driven improvements in efficiency (as measured by cost per well), may not be enough to make the gas economically viable.

7. At a more general level, there have been a lot of technology advances in the gas industry, some of which have been disappointingly small, and some of which have been disconcertingly large. You mention coal-bed methane on the small side. But the suite of advances in the 1980s (including much better markets) led to more than 15 years of low (often very low) prices. They're what created and sustained the overhang you mention. Which side does shale fall on? I don't think we know for certain yet. But the sheer volume of what's already happening looks awful big, and there sure seem to be a lot more places to go. But if the demand doesn't increase, and prices stay low due to an abundance

of gas, and costs don't improve that much, it might not be economical to produce shale gas.

8. Are low prices good for companies? Of course not. But the essence of competition is that the companies can't always get what they want. And they are forbidden by law from colluding. So … to the extent that they let their hopes color their expectations, they can get in a lot of trouble. And often have.

9. Shale does have features that mean we are likely to see quite different market outcomes in the future, whatever the prevailing price turns out to be. In particular, the high decline rates mean that production should be much more sensitive to price over a period of weeks to months than it was before. If the industry stops drilling for a while, supply will respond relatively quickly, and if they start up again, supplies will go back up fairly quickly. I can't imagine this approach would go hand-in-hand with drilling efficiency and reduced costs. Since companies aren't allowed to coordinate, could this supply/demand response oriented drilling really succeed? I'm not sure This is a level of flexibility that we haven't seen before and is likely to reduce price volatility except in places that are pipeline constrained (the far Northeast).

10. Also, I could make the case that shale has an artificially high price at anything much over, say, \$3.50 to \$4.00. There's a great deal of gas available in the Middle East, Nigeria, and Central Asia that is VERY cheap to produce. If the world had a moderately efficient global market for gas, what would the price of LNG become? In some ways, the current price may be propped up by the successful anti-competitive global markets (I saw at one point that Qatar was delivering gas to Kuwait for \$0.10). I'm not holding my breath on international markets changing – but I would say a couple of things: If costs are not reduced via learning curves and technology, why would companies want to produce shale if the potentially artificially high price isn't even high enough to break even? It seems like improved international gas trading would only hurt the shale gas position.

a. Other things being equal, it will eventually be a lot harder to hold a gas cartel together than to hold OPEC together, just because there are so many places to get the gas.

b. While oil looks intrinsically scarce around the world, gas does not. That means, at the very least, that competitively priced gas will remain far cheaper than oil (expect during financial crashes) for as far as the eye can see. That's one of the reasons that gas prices don't correlate with oil prices these days, even though I think many other commodity prices do. So – yes, the raw material need to drill gas wells may well go up in price. But it's not clear that signals much more than a general inflationary force that applies to much of the economy. Certainly, most other energy source would be equally subject to it.

11. Just skimming through the Berman article – yes he makes a lot of interesting points. The first (and some ways the biggest) I entirely agree with and have for many years –

whatever happens going forward, it's not going to be smooth curves. Yes, I realize EIA can't predict volatility. And the jumpiness of the curves matters a lot, I suspect. Yes, the reality is more likely volatililty. I have to wonder if volatility will ultimately benefit or hurt the shale gas industry as a whole. I don't find myself terribly persuaded by some of his other points. For example, he says that the only number that matters is proved developed reserves. That's just wrong. That number reflects how much gas it has been worthwhile for companies to prove up – it amounts to current inventory. I think the point he is making is that just because the gas is there, doesn't mean companies can afford to get it out of the ground. There is lots of hydrocarbon in the ground that isn't scheduled to be produced just because it's not economical to do so. If they had found much more, arguably, it would be a market failure, because there's no point in getting inventory too far ahead of production. I feel like inventory is already ahead of production, which is why I think this market could potentially fail or have a hard enough time stabilizing that it severely disrupts the industry plans to produce all this gas. In that connection, one of the strongest arguments for relatively low gas prices comes from the proved reserve estimates: Over the last couple of years, companies have increased their proved reserve estimates (only by 2%, right? And one could argue that some of this is the result of the change in SEC rules, while some of it may be to attract investors and improve company value, with the majority of the increase coming from drilling that had to occur due to lease terms and debt servicing), even in the face of significant price declines. (which is why I think many of these companies may be set up for failure) That means

a. they've added significant amounts of new gas to their current inventory that

b. they judge they can produce a ***current*** prices (not $7 or $8) while (at least they want to appear this way; I think the companies are still figuring out what they can economically produce, they are still learning how their assets might perform) These judgments are also based on estimated ultimate recovery; say that shale wells don't produce as much as a company thought, or their portfolio as a whole doesn't meet expectations. Suddenly what was thought to be x return on y investment per well might end up being .6x return on y investment, which would make their judgment about break even cost wrong. Given my discussion with the [redacted] at some major companies, they are skeptical that the portfolios will perform as their business and engineering managers would like them to. Disconnect between resource evaluators and business managers who want bonuses and want to take the risk to win big is not uncommon.

c. they still think they can produce most of the inventory they had last year, even at lower prices and (they almost have to, given lease and debt obligations)

d. the increase is enough to more than make up for pretty high production levels.

12. Now the companies may be mistaken in their estimates, but these are numbers that have to be filed with the SEC to inform investors, and are therefore not your normal kind of propaganda (There are consequences to deceiving investors of course-or themselves-, especially in the long term, but that hasn't stopped companies from doing it; I'm reminded of a Shell. There are incentives to being optimistic, as well as pitfalls of course). In any case, when you come on a resource that you know little about (as for shale), the amount available is very hard to guess. And sometimes, people guess way high (Sable Island, anyone). In the hysteria of the moment, they may well be doing that here. And yet, the deposits are so widespread and so various, that it seems unlikely that it will all disappoint-but how much will disappoint vs outperform expectations? I think that's a big question. (as was the case for a much less diverse resource at Sable Island). In that sense, I agree that the ultimately recoverable numbers aren't very important – whatever the right answer is, it's big enough not to matter very much for quite some time. A different question is whether all the further shale plays will be substantially more expensive than the ones we already know. Perhaps, but it seems unlikely. I think it really depends on how the various plays turn out as they are developed, and how economical they are relative to the ones currently in focus. More likely is the possibility that the environmental issues will overwhelm the system and shut down shale prospects. That could happen – it's easy to see how it might. Perhaps it's about as likely as really meaningful carbon limits? I wouldn't bet a lot on either one, personally.

[redacted]

[redacted]

[redacted]

[redacted]

# Uncertainties in shale gas resources & production: overview of topics

- Considerable shale play/formation heterogeneity
- Shale productive capability is largely untested
- Long-term decline and recovery rates are unknown
- Producers maximize rates of return (ROR), not resource recovery
- Recovery rates depend on gas prices
- Re-fracturing potential is unknown
- Public information bias creates expectations toward overstating "typical" shale gas well recovery and profitability

# Considerable shale formation heterogeneity

"Serving as source, trap and seal, shale beds have characteristics that vary not only from region to region but also within specific plays and fields. In fact, there often are significant well-to-well variations in gas production within a single field…. Where there is large variability in production from well to well, it clearly tends to challenge any assumption that shales and their indigenous hydrocarbons are simple and consistent."

**Source: American Association of Petroleum Geologists, Explorer Magazine, "Shales – Similar, Yet So Different," by Louise S. Durham, September 2010, pages 28, 33.**

# Considerable shale formation heterogeneity

Shales plays/formations in petroleum basins vary by:

- Depth
- Formation Thickness
- Pore Pressure
- Carbon Content
- Pore Space (Less porosity ü Less gas in-place)
- Carbon Maturation (exposure to temperature and pressure over geologic time, which determines the extent to which oil and gas were produced)
- Gas-Oil-Water Content (Oil and water capillary pressure might impede gas and oil flow.)
- Clay Content (More clay ü shorter fracture length and/or higher fracturing pressure/higher cost)

# Considerable shale formation heterogeneity

- Initial shale gas well production rates can vary by as much as a factor of 10 across a formation.
- Adjacent gas well productivity can vary by as much as a factor of 2 or 3.
- Each well produces like a “field” that is independent of the productivity of the adjacent wells (“fields”). (Only one chance to get it “right.”)
- Well production variability complicates “optimization,” which requires experimentation across a sufficient number of wells to determine the optimal drilling and completion technology for a specific formation subregion. Some gas well production variability due to the “learning curve” experimentation.

# Considerable shale formation heterogeneity

- Barnett shale gas wells exhibit significant variability regarding initial gas production rates.
- This variability in initial gas production rates has a profound impact on rates of return.
- Some parties have estimated that potentially up to 25 percent of the Barnett wells are unprofitable under certain circumstances. (See next slide)

# Considerable shale formation heterogeneity

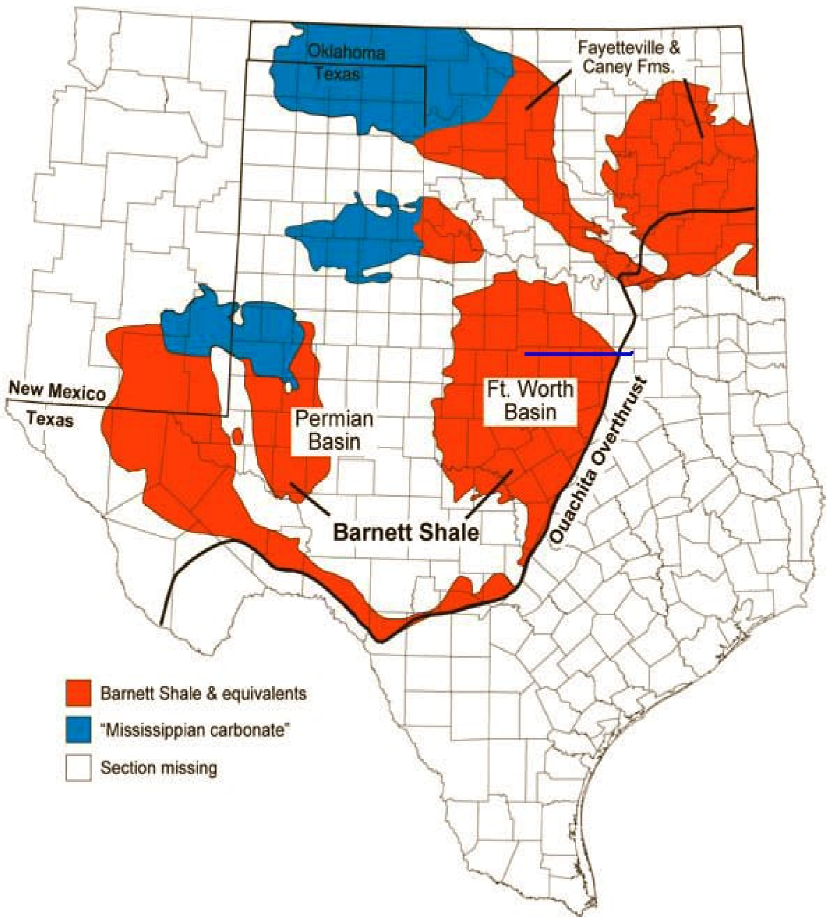
- Well-to-well production variability results in considerable variability in profitability and rates of return (ROR), which increases producer risk, the required ROR, and the weighted average cost of capital.

- An analysis based on the gas production profiles of 389 wells in three 9-square mile areas of the Barnett shale and using a $7.00 per MMBtu wellhead gas price concluded that "the 25th percentile areas based on EUR are not economically viable, the 50th percentile areas are almost economically viable, and the 75th percentile areas are reasonably economically viable." **Source: "Economic Evaluation of Shale Gas Reservoirs," by John D. Wright, Norwest Corporation, Society of Petroleum Engineers Paper Number 119899, November 2008.**

# Shale productive capability is largely untested

- Many shale gas formations have not been extensively production tested (i.e., many wells in many different locations).
- Well productivity data are largely confined to known "sweet spots."
- Many shale formations are so large that only a small portion of the entire formation has been extensively production tested, e.g., the Marcellus Shale.

# Portions of the "mature" Barnett shale remain untested

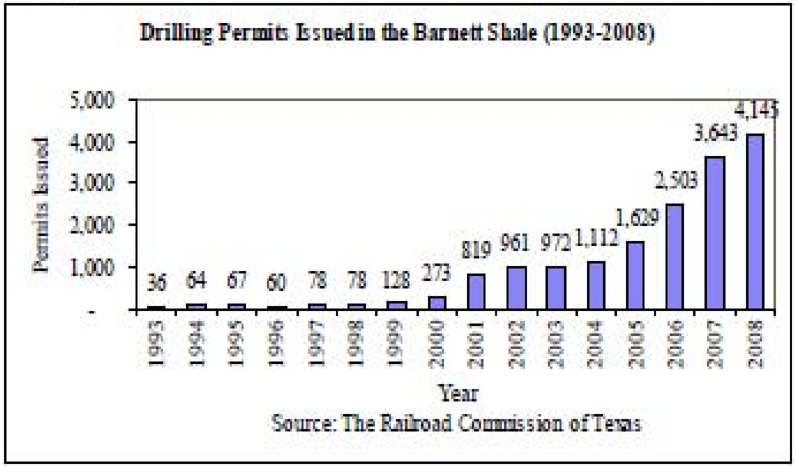



- In north-central Texas, the Barnett shale covers all or part of at least 30 counties. Wells have been drilled in about 23 counties, with most of the wells drilled in 5 or 6 counties.
- The Barnett shale also exists in the Permian Basin in west Texas. Only a few wells have been drilled in the west Texas Barnett, which were deemed to be "disappointing" and so no further drilling has occurred there, but could occur later.

Note regarding map – Shale labeled as "Fayetteville" is actually the Woodford Shale.

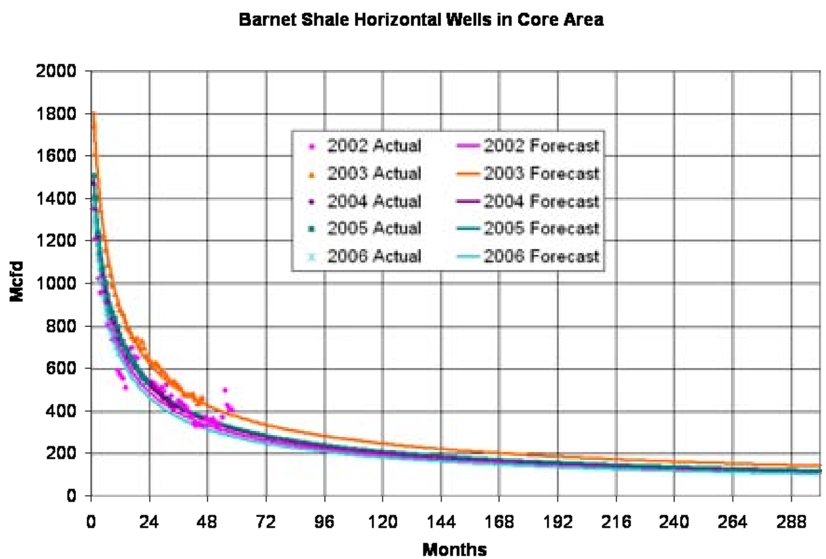
# Long-term decline and recovery rates are unknown

Drilling Permits Issued in the Barnett Shale, 1993-2008




- Even in the relatively "mature" portions of the Barnett shale most of the wells are only five years old, with about 50 percent of the total wells drilled in the last 3 or 4 years.
- Other basins are much less mature with most of the wells were drilled in the last 3 years.
- So there is not much production history for most of the basins or subregions within a basin.

# Long-term decline and recovery rates are unknown




- Most producers use hyperbolic decline rates that show rapid initial production decline rates, followed by relatively level production rates for up to 30 years.
- If long-term production does not follow the hyperbolic curve, but declines more rapidly than projected, then total recovery would be considerably less than the cumulative volume estimated by the hyberbolic curve.
- Hyperbolic “curve fitting” around “noisy” production data across many wells causes uncertainty in recovery estimates. (See 2002 data.)

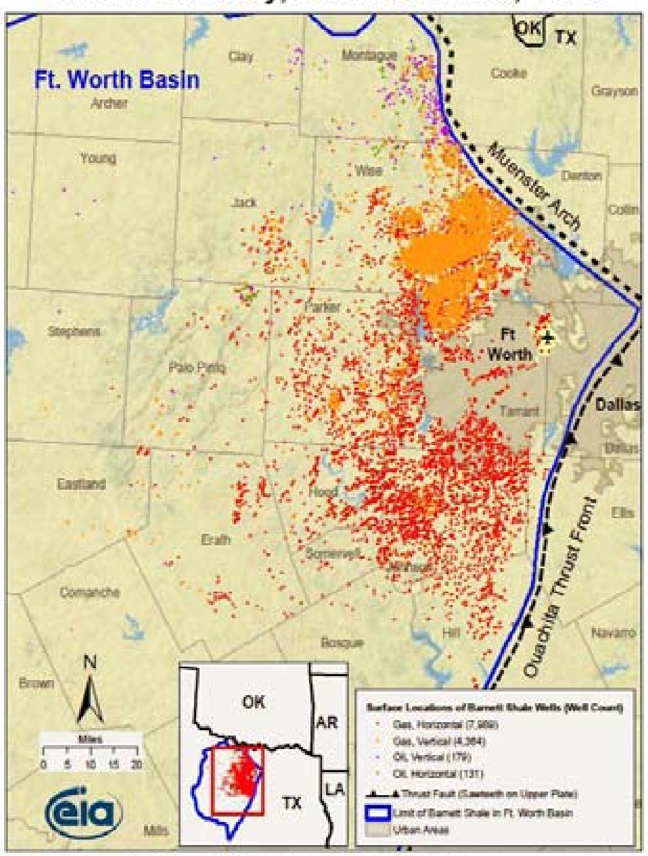
# Producers maximize rates of return, not resource recovery

Maximizing ROR by maximizing initial production rates and cash flow.

- High short-term gas production rates possibly at the expense of long term recovery due to fracture closure.
- Only recently have producers started using well chokes to cut back initial production rates and maintain reservoir pressure.  Well chokes prevent sand buildup at the wellbore and maintain pressure that might reduce the rate at which fractures close-up and production declines.
- In thicker portions of the Barnett shale, some vertical wells are still drilled to minimize costs and maximize ROR.

# Barnett shale drilling, horizontal and vertical wells

Barnett Shale Play, Fort Worth Basin, Texas




Source: Energy Information Administration based on data from HPDI, USGS, Pollastro et al (2007)
Updated: July 27, 2009

- Drilling a vertical foot is about 1/2 the cost of drilling a horizontal foot.
- In the thicker northern portion of the Barnett shale, some of the wells are still being drilled as vertical wells, because they are considerably cheaper to drill than horizontal laterals.
- Closer well spacing compensates for the lack of horizontal laterals.

# Recovery rates depend on gas prices

As Gas Prices Decline, Costs Can Be Reduced By:

- Shorter horizontal laterals,
- Longer fracturing stages (i.e., less hydraulic fracturing stages for a given lateral length),
- Less re-fracturing potential for an existing shale well.

- As gas prices approach operating costs, low production wells will be plugged and abandoned, leaving unproduced gas resources in the ground.

# Recovery rates depend on gas prices

Shale gas well profitability and ultimate recovery will remain difficult to estimate because:

- Lack of public data with regard to capital and operating costs (e.g., leasehold, drilling and completion, maintenance, geophysical, water, etc.). Problem is complicated by the fact that each producer has a unique approach to drilling, completing, and managing its wells. Major producers [e.g., Oxy*] are more "tight-lipped" than the independents.
- Further complicated by volatile gas prices, learning curve dynamics, evolving producer practices and technologies.

* Occidental hasn't revealed from which Southern California shale beds they are currently producing oil and gas. Occidental has only revealed that the shale production is occurring in Kern County.

# Re-fracturing potential is unknown

- Little re-fracturing has been done because most shale gas wells are relatively new.
- Initial production rates and total cumulative production of re-fractured wells are unknown.
- So re-fracturing economics (cash flow vs. costs) are unknown.
- Do other party resource estimates assume re-fracturing? (Don’t know.)

# Public data might overstate shale gas recovery & profitability

- Producers search for and drill in formation "sweet spots" with high initial production rates to maximize the returns to capital.

- Producers "trumpet" their ROR successes and are silent regarding their ROR failures. (Failures continue to produce so long as the wells cover their operating costs.)

- So public information on production rates and rates of return is biased toward the highest production rate wells located in "sweet spots," thereby potentially biasing expectations as to what is "normal."

# Public data might overstate shale gas recovery & profitability

- Some of the current gas drilling in some shales is occurring to hold leases that usually expire after 3 years. Leasehold drilling exaggerates the appearance of shale gas well profitability.

- Gas shale lease purchases of up to $25,000 per acre, resulting in up-front costs of as much as $2 million per 80 acres per well, give producers a financial incentive to continue drilling to recover lease costs, even at low gas prices.

# Conclusions

1. Estimates of shale gas formation productivity and resource potential will be problematic until the entire formation has been production tested (i.e., a sufficient number of wells with sufficient production histories in enough locations throughout the entire formation, with some experimentation).

1. Actual shale gas resource recovery will depend on ever-changing natural gas prices, e.g., lower prices will result in less shale gas resource recovery.

1. Estimated ultimate recovery is a “moving target” as gas prices, technology, and production costs change.

# Conclusions

- Question: When is the ultimate recovery of an oil and gas field/play precisely known?
- Answer: When the last well is plugged and abandoned.
- Lesson: Until final abandonment, every statement regarding a shale play's ultimate resource recovery is an estimate, subject to revision.

From: [redacted]
Sent: Wednesday, April 13, 2011 3:11 PM
To: [redacted]
Subject: RE: Presentation on Shale Gas Uncertainties

[redacted]

I agree with your concerns regarding the euphoria for shale gas and oil and that we might be in a "gold rush" wherein a few folks have developed "monster" wells so everyone assumes that all the wells will be "monsters."

[redacted] and I have been particularly concerned and we add a note of caution wherever we can. See attached draft document. Please note that you can use the numbers in the attached draft document for your article, but because the document is still being reviewed it can't yet be cited because it doesn't officially exist (catch-22).

As a species, we are blind to our own ignorance. The older I get, the more I learn, the more ignorant I feel. (Notice that the root for "ignorance" is "to ignore.") Moreover, human beings also abhor uncertainty, even though it is a pervades our lives. …..But we can save this philosophical discussion for another time.

[redacted]

[redacted]

**From:** [redacted]
**Sent:** Tuesday, April 19, 2011 1:27 PM
**To:** [redacted]
**Cc:** [redacted]
**Subject:** What's so special about shale gas NGLs...nothing on the face of it

Dear Colleagues,

The has been much press discussion regarding the NGLs produced from shale formations. From the press's enthusiasm, one might infer that shale gas is particularly rich in NGLs. However, the enclosed graph charts the Barrels of NGLs produced per MMcf of Dry Gas Production. <u>The barrels of NGL produced per MMcf of dry-gas production has averaged about 0.091 bbl/MMcf since 1973, with a standard deviation of 0.006</u>. This graph suggests that, on average, the NGL richness of shale formation might not be significantly different than that of any other play. Of course, these aggregate data obscure the individual contribution that shales and other formations contribute to NGL production. Even so, in order for shale gas production to make a **more significant** contribution to NGL production, then the NGL contribution coming from other production sources would have to be falling in lock-step with the rise in shale's NGL production to give the smooth time-trend. Not likely.

For example, since 2005, natural gas liquids production has steadily increased from 1.7 million barrels per day to 2.0 million barrels per day, an <u>18 percent increase</u>. The growth in natural gas liquids is due to the overall growth in natural gas production, which increased from 18.0 trillion cubic feet in 2005 to 21.6 trillion cubic feet in 2010, a <u>20 percent increase</u>. So as gas production rises, so too does NGL production. End of story.

[redacted]

**From:** [redacted]
**Sent:** Monday, October 26, 2009 11:24 AM
**To:** [redacted]
**Subject:** Update

Good Morning,

I hope you had a nice week out of the office. I now have a new computer, and a new phone number that works! Things are looking up.

[redacted]

Sent a copy of what we have so far to [redacted].

Talked to [redacted] last week. He is in OIAF. They are working on a model in which hydro fracking is outlawed (extreme case, I know). We discussed the API report that explains the implications of increased regulation of fracking. [redacted] looked into some of the assumptions of the report and conducted an interview. He believes the API report is exaggerated and bogus. He emailed me his findings. He is also keeping me updated on whatever he finds regarding water treatment.

I'm keeping abreast of the Clean Energy Jobs and American Power Act hearings taking place this week. I hope to listen to the hearings via webcast starting tomorrow.

I started working with [redacted] last week to get the webpage put together. She is assisting [redacted] with the design. She is making good headway. I've supplied her with all of the images that I think will probably make it onto the website. I'm waiting to see if the industry vetters are willing to replace the ones from the environmental blogs before she starts working those into the [redacted]

I may still need to add a few sentences to [redacted]. I found a recently published study on air quality and its health effects in Dish, TX, which is in the Barnett. I haven't read it yet, but will soon. [redacted] also informed me of a late 2007 NRDC report on health effects of drilling. [redacted] I may also add a little to the water treatment section. [redacted] also sent me an article that better explains the necessary treatment process for produced water.

I'm also trying to get a few more people in on the glossary additions/edits discussion to critique what [redacted] came up with.

Is there anyway I could make a trip with you to the supply store today or tomorrow morning? I could use another pen or two and a pair of headphones to listen to the hearings and a water treatment webinar later this week (My headphones fell out of my pocket on the way to work last week, so I could use some that I could just leave at the office instead of toting my personal pair back&forth).

[redacted]

Good luck getting back into the office groove this week!

[redacted]

[redacted]
Office of Oil and Gas
Energy Information Administration
United States Department of Energy
[redacted]
[redacted]@eia.doe.gov

[redacted]

---------- Forwarded message ----------
From: [redacted]@eia.doe.gov>
To: [redacted]@eia.gov>
Date: Mon, 19 Oct 2009 04:57:58 -0500
Subject: Cheers and Two Ideas

[redacted]

From: [redacted]@fastmail.fm]
Sent: Wednesday, April 27, 2011 10:46 PM
To: [redacted]
Subject: [redacted]

1) Be happy indeed -- you are not crazy. But not everyone is over-endorsing.

2) AEO2011's rosy view of the shale gas future is what you get when the current senior managers' predilections are in effect and their modeling minions are forced to rely way too much on data from press releases and journalist's reports, i.e., incomplete/selective and all too often unreal data.

3) Contradistinctly, at 1100 today PGC press-released its 2010 estimates. Summary is here: http://www.potentialgas.org/ . EIA's shale gas resources went from 368 Tcf for AEO2010 to 827 Tcf for AEO2011, a whopping 459 Tcf or 125 percent increase, detailed explanation lacking so far. PGC's went from 616 Tcf in its 2008 report to 687 Tcf in its 2010 report, a modest 71 Tcf or 11.5 percent increase primarily due to local re-evaluations.

4) EIA, irrespective of what or how many "specialty" contractors are hired, is NOT TECHNICALLY COMPETENT to estimate the undiscovered resources of anything made by Mother Nature, period. The modelers previously got away with it for tight sands (without ever involving the former OOG) simply because that resource wasn't initially a very significant piece of the total pie and its subsequent development was slow. Apparently management decided it could do the same again for shale gas. Not so, entirely different beast.

5) Its been my experience disconnects from those who are most knowledgeable about the resource base and its potential economic extractability is what almost invariably happens when the folks steering the bus don't know crap about rocks and their fluid content.

On Wed, 27 Apr 2011 17:24 -0400, [redacted]@eia.gov>
wrote:
After the conference today, I decided they should have changed the name to EIA Natural Gas Conference 2011; I haven't even heard that sort of cheerleading from an "unbiased" organization in a while.

I imagine you have seen Art Bermans article in the Oil Drum on our AEO highlights? It's linked below.  I haven't had a chance to dig down into the full AEO release yet.

Am I just totally crazy, or does it seem like everyone and their mothers are endorsing shale gas without getting a really good understanding of the economics at the business level? I know there is a lot of gas out there, but I'm not sure it matters if it can't fetch a price to pay for the cost to produce it.

[redacted]

**From:** [redacted]
**Sent:** Wednesday, November 04, 2009 2:26 PM
**To:** [redacted]
**Subject:** RE: Shale Gas Map with Resource Estimates

Right – they are technically recoverable resources, probably on the high side in some cases, but there is not enough history in most shale basins to make a better estimate.
[redacted]

---

**From:** [redacted]
**Sent:** Wednesday, November 04, 2009 1:16 PM
**To:** [redacted]
**Subject:** RE: Shale Gas Map with Resource Estimates

According to [redacted] table, these are not the in-place estimates (which is a separate column in the table) but technically recoverable resources.
-----Original Message-----
**From:** [redacted]
**Sent:** Wednesday, November 04, 2009 12:41 PM
**To:** [redacted]
**Subject:** RE: Shale Gas Map with Resource Estimates
We must clearly indicate that our use of selected shale gas resource numbers from whatever source(s) ought not be construed as OOG or EIA endorsement thereof.

Are these all in-place estimates? We shouldn't show a mix of in-place and technically recoverable/economically recoverable types of estimates. If they're all in-place estimates then the key label should read "Maximum In-Place Shale Gas Resource Estimates (Tcf)" .

The title should perhaps be "Lower 48 States Shale Gas Plays with Selected (In-Place ??) Resource Estimates".

[redacted]
**Office of Oil and Gas**
**Energy Information Administration**
[redacted]@eia.doe.gov

**From:** [redacted]
**Sent:** Wednesday, November 04, 2009 1:16 PM
**To:** [redacted]
**Subject:** RE: Shale Gas Map with Resource Estimates

According to [redacted]'s table, these are not the in-place estimates (which is a separate column in the table) but technically recoverable resources.

---

**From:** [redacted]
**Sent:** Wednesday, November 04, 2009 12:24 PM
**To:** [redacted]
**Subject:** Shale Gas Map with Resource Estimates

Attached is first pass map of shale gas resources per play using graduated symbols from [redacted]'s spreadsheet. That spreadsheet only has the maximum resource number per basin so that is all that is shown.

Note that a lot of plays do not have estimates, including active ones such as the Eagle Ford.

Some play outlines (e.g. Haynesville) are completely masked by the red ball symbols.

The arrows connecting the Marcellus & Devonian (Oho) names to symbols cross each other, which looks somewhat awkward. I can move the symbols so that they don't.

Do we need more verbiage on the source of the resource estimates?

No background on the map because this is the ArcGIS Online data which won't display on my PC. User Services will not allow troubleshooting this issue using GoToAssist which is ESRI's support tool, so I will try to find a solution or a work around.

[redacted]

**From:** [redacted]
**Sent:** Tuesday, November 03, 2009 4:24 PM
**To:** [redacted]
**Subject:** FW: AEO Basin Estimates

Who said anything about formal OOG adoption? Bad bad idea. Should we elect to show them, attribution must be to the 2010 AEO assumptions document and OIAF, not us.

**From:** [redacted]
**Sent:** Tuesday, November 03, 2009 4:12 PM
**To:** [redacted]
**Subject:** FW: AEO Basin Estimates

**From:** [redacted]
**Sent:** Tuesday, November 03, 2009 4:11 PM
**To:** [redacted]
**Cc:** [redacted]
**Subject:** RE: AEO Basin Estimates

This is interesting in that I don't think that, as long as OOG is on board with these as gas shale resource estimates, that they can't adopt them as their own. Thoughts?

**From:** [redacted]
**Sent:** Tuesday, November 03, 2009 3:48 PM
**To:** [redacted]
**Cc:** [redacted]
**Subject:** RE: AEO Basin Estimates

Because we haven't "officially" released the Annual Energy Outlook (AEO) 2010 projections yet, I'm not sure whether it would be appropriate for OOG to use the AEO 2010 shale gas resource estimates in its basin maps. However, the AEO 2010 shale gas resource estimates are higher than those used to create the last year's AEO projections.

What is the time frame for when the basin estimates would be published on the OOG maps?

In any case, I would talk with [redacted] at extension [redacted] regarding your request.

**From:** [redacted]
**Sent:** Tuesday, November 03, 2009 3:36 PM

**To:** [redacted]
**Subject:** AEO Basin Estimates

Good Afternoon,

We are trying to find some basin resource estimates for shale gas in order to add them to a shale gas basin map. We don't think the PGC will let us use their estimates since they aren't published yet. In the AEO, under the assumptions section, there are some estimates for shale resources on a regional scale. Do you know who in your office I could talk to regarding the source for these estimates? We are hoping that they have estimates on a basin to basin basis that they could share with us. Thanks,

[redacted]

http://www.eia.doe.gov/oiaf/aeo/assumption/oil_gas.html

[redacted]
Office of Oil and Gas
Energy Information Administration
United States Department of Energy
Phone: [redacted]
[redacted]@eia.doe.gov

[redacted]

From: [redacted]@eia.gov>
Date[redacted]
Subject: FW: someone should pass this to those folks from W.VA
To: [redacted]

-----Original Message-----
From: [redacted]@gmail.com]
Sent: Wednesday, September 16, 2009 6:05 PM
To: [redacted]
Subject: Re: someone should pass this to those folks from W.VA

unbelievable! I can't say that I remember what we wrote very well! But
I do think that we were pretty unbiased through and through!

Keep the faith [redacted] You are doing good and important work and your
efforts are serving us all!

On Wed, Sep 16, 2009 at 9:15 AM, [redacted]
<[redacted]@eia.doe.gov> wrote:
>
> Thanks, I'll drop this down the hole under my desk; it's specially
> designed to deliver mail to mines in China, South America, Africa, and,
> of course, West Virginia.  I'm not sure how the delivery system works; I
> think they stuff insubordinate HR folks down there until they can learn
> to behave. Only the skinny ones though... of course those are in short
> supply.
>
> **I'm working on reading through [redacted]'s edits... [redacted] think**
> **that portions of the environmental and health sections are**
> **"inflammatory" towards industry and that these sections should be**
> **watered down... more.**
>
> **Maybe we should just frac them.**
>
> **I'm wondering what the eff I am really here for if they already have**
> **their own versions of the "unbiased, objective, EIA Truth".** [redacted]
> [redacted]
> [redacted]
>
>

> [redacted]
>
>
> -----Original Message-----
> From: [redacted]@gmail.com]
> Sent: Tuesday, September 15, 2009 8:57 PM
> To: [redacted]
> Subject: someone should pass this to those folks from W.VA
>
> http://www.treehugger.com/files/2009/09/switching-renewables-new-jobs.ph
> p?dcitc=th_rss
>
>
>
> --
> [redacted]
> [redacted]@gmail.com
> [redacted]
>
>
>

**From:** [redacted]@eia.doe.gov]
**Sent:** December 11, 2009 10:04 AM
**To:** [redacted]
**Subject:** RE: Shale Review
[redacted]

I was the one responsible for printing all of the word documents that were sent to you. Somehow I failed to print and send you our document on federal regulations. I realize that some of our work is a little vague; I think this is the result of us trying to avoid being too pointed. It seems that science is pointing in one direction and industry PR is pointing in another. We still have to present the middle, even if the middle neglects to point out the strengths of scientific evidence over PR.

Instead of me calling you and asking you about each law/regulation (or lack of it), would you mind making comments on the Regulations document with the Track Changes feature in Word, if you have the time?

I've gone through and taken the rest of your comments into consideration. They were all very helpful, especially where [redacted] took the industry PR as truth (for example, "Fracking has never caused contamination"... yea right, and the 2004 EPA report that helped exempt fracking from SDWA was scientific and not political... that was sarcasm in case you couldn't tell.) [redacted] I think I can safely say that trusting industry to regulate itself is a bogus idea, comparable to letting the wolf guard the hen house. [redacted] I've had a lot of exposure to situations where greed and lack of social responsibility goes unchecked, undermining the wellbeing of our society and environment. Fortunately there are still people who value nature in its pristine, original form and the collective good over the pockets of a few. This isn't to say that I don't support responsible development of natural gas... I just don't support states throwing caution to the wind in the hopes of speedy monetary reimbursement.

[redacted] I think there is a certain side of this story that has not been shared with the public, although obviously more research and empirical data is needed. I think once (or if) that data becomes available, the public will be surprised with how hazardous and haphazard some of this development in the past has been.

I've attached a [redacted] report. Is the attached report the same report as the one you mentioned in your comments? Also, are there any other good sources that just jump out at you that you think we should include? [redacted] Let me know if you have any other suggestions and if you have the time to review our Regulations document.

PS Disclaimer: my opinions do not reflect the attitudes of the EIA or DOE; they are my words and ideas... although it would be nice if all of the industry economist, engineers, and geologists around here agreed with me. ☺

Thanks again,

[redacted]
Office of Oil and Gas
Energy Information Administration
United States Department of Energy
Phone: [redacted]
[redacted]@eia.doe.gov

**From:** [redacted]
**Sent:** Thursday, August 13, 2009 4:30 PM
**To:** [redacted]
**Subject:** Drafts for editing

[redacted],

Just stopped by your office, but you were out. Almost all of the content is ready, minus a couple of production pages and a surface disturbance page. These exclusions are indicated in [redacted] within the zip file for him. [redacted] says [redacted] will be ready next week. The .ZIP file is about 27 megabytes. He should be able to download it, although it may take a few minutes.

I also have my reservations about a couple of the pages representing the touchier issues. It seems that instead of delving into the conflict issues and presenting lots of information from both sides, we may have steered around them a little bit, resulting in less content that may be too generalized. [redacted] did a great job with the frac fluid pages and presented a substantial amount of info on either side of the issue, but some of the environmental and socioeconomic pages seem a bit vague, without many external sources or references. Maybe this is OK for those issues, but it's my opinion that some of these pages deserve a second look if we want [redacted] to be truly in-depth and comprehensive. (For future project planning, it would have been nice to have [redacted]. Many of the hardest [redacted] to research and write were not dealt with until towards the end of the summer; I think people were either a little burned out, or tried to rush through them.

I'll be in the office tomorrow, so I am going to take a second look at these pages [redacted] and make some comments if I think we may have overlooked something. I'd like to sit down and get your opinion on a couple of these pages to see if you think I should add a little bit more to them. I'm also going to try to finish a draft of what [redacted] may want for his [redacted] by the end of the day tomorrow. I'd like to run that by you on Monday before I leave if you have time. Thanks,

[redacted]

[redacted]
Office of Oil and Gas
Energy Information Administration
Department of Energy
[redacted]@eia.doe.gov
[redacted]

From: [redacted]@eia.doe.gov>
To: [redacted]
Date: Thu, 17 Sep 2009 15:58:50 -0500
Subject: Horizontal Drilling

[redacted],

It was wonderful to connect a voice to a voice, as it were. The first place to look for a diagram is a report that the Fossil Energy group in DOE put out this spring. The link is to the whole report (which is good in many ways, but perhaps a bit on the rosy side for some tastes). They have a diagram on page 46 for horizontal vs. vertical drilling.

http://fossil.energy.gov/programs/oilgas/publications/naturalgas_general/Shale_Gas_Primer_2009.pdf

[redacted]

[redacted]
Office of Oil and Gas
Energy Information Administration
[redacted]

U.S. Department of Energy • Office of Fossil Energy
National Energy Technology Laboratory

# Modern Shale Gas Development in the United States: A Primer

April 2009

Ground Water Protection Council
ALL Consulting
NETL
U.S. Department of Energy

## DISCLAIMER

# Modern Shale Gas
## Development in the United States:
# A Primer

Work Performed Under DE-FG26-04NT15455

Prepared for
U.S. Department of Energy
Office of Fossil Energy
and
National Energy Technology Laboratory

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April 2009

# ACKNOWLEDGMENTS

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GWPC and ALL Consulting wish to extend their appreciation to the following federal, state, industry, and educational institutions which helped with numerous data sources, data collection and technology reviews that were critical to the success of this project. Additionally, the extra time and energy that individuals provided in reviewing and in broadening our understanding of the issues at hand is respectfully acknowledged.

The authors wish to specifically acknowledge the help and support of the following entities: Arkansas Oil and Gas Commission, Louisiana Department of Natural Resources, Michigan Department of Environmental Quality Office of Geological Survey, Montana Board of Oil and Gas Conservation, Montana Department of Natural Resources, New York State Department of Environmental Conservation, Ohio Department of Natural Resources Division of Mineral Resources Management, Oklahoma Corporation Commission, Pennsylvania Department of Environmental Protection, Railroad Commission of Texas, State of Tennessee, State University of New York at Fredonia, West Virginia Department of Environmental Protection, Energy Information Administration, U.S. Environmental Protection Agency, State Review of Oil and Natural Gas Environmental Regulation, Inc. (STRONGER), BP America Production Co., Chesapeake Energy Corp., Devon Energy Corp., East Resources, Inc., Fortuna Energy Inc., Independent Petroleum Association of America, Schlumberger Ltd., Universal Well Services Inc., and Weatherford International Ltd.,

# FOREWORD

This Primer on Modern Shale Gas Development in the United States was commissioned through the Ground Water Protection Council (GWPC). It is an effort to provide sound technical information on and additional insight into the relationship between today's fastest growing, and sometimes controversial, natural gas resource development activity, and environmental protection, especially water resource management. The GWPC is the national association of state ground water and underground injection agencies whose mission is to promote the protection and conservation of ground water resources for all beneficial uses. One goal of the GWPC is to provide a forum for stakeholder communication on important current issues to foster development of sound policy and regulation that is based on sound science. This Primer is presented in the spirit of furthering that goal.

Water and energy are two of the most basic needs of society. Our use of each vital resource is reliant on and affects the availability of the other. Water is needed to produce energy and energy is necessary to make water available for use. As our population grows, the demands for both resources will only increase. Smart development of energy resources will identify, consider, and minimize potential impacts to water resources.

Natural gas, particularly shale gas, is an abundant U.S. energy resource that will be vital to meeting future energy demand and to enabling the nation to transition to greater reliance on renewable energy sources.

Shale gas development both requires significant amounts of water and is conducted in proximity to valuable surface and ground water. Hence, it is important to reconcile the concurrent and related demands for local and regional water resources, whether for drinking water, wildlife habitat, recreation, agriculture, industrial or other uses.

Because shale gas development in the United States is occurring in areas that have not previously experienced oil and gas production, the GWPC has recognized a need for credible, factual information on shale gas resources, technologies for developing these resources, the regulatory framework under which development takes place, and the practices used to mitigate potential impacts on the environment and nearby communities. While the GWPC's mission primarily concerns water resources, this Primer also addresses non-water issues that may be of interest to citizens, government officials, water supply and use professionals, and other interested parties.

Each state has laws and regulations to ensure the wise use of its natural resources and to protect the environment. The GWPC has conducted a separate study to summarize state oil and gas program requirements that are designed to protect water resources. These two studies complement one other and together provide a body of information that can serve as a basis for fact-based dialogue on how shale gas development can proceed in an environmentally responsible manner under the auspices of state regulatory programs.

This Shale Gas Primer was intended to be an accurate depiction of current factors and does not represent the view of any individual state. Knowledge about shale gas development will continue to evolve. The GWPC welcomes insights that readers may have about the Primer and the relationship of shale gas development to water resources.

Scott R Kell

Scott Kell, President,

Ground Water Protection Council

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# EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

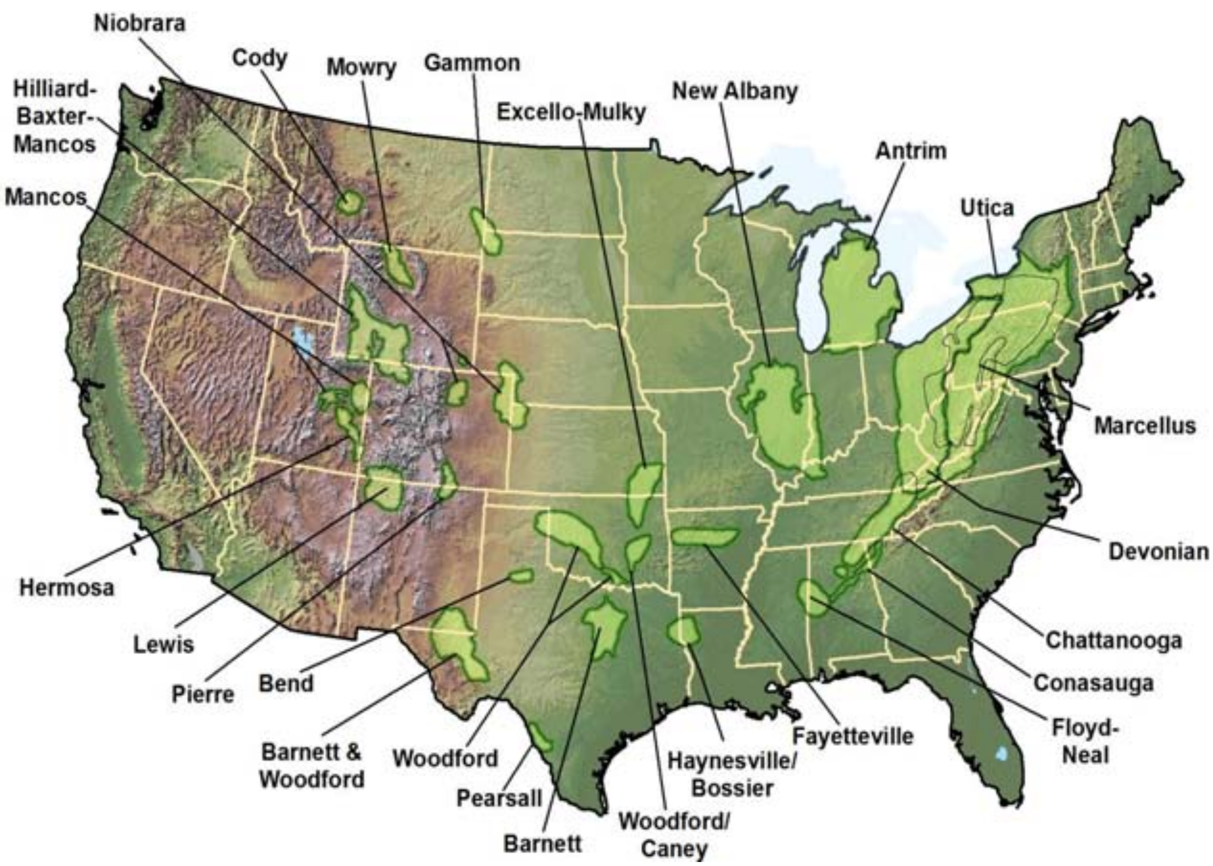
The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. Exhibit ES-1 shows the approximate locations of current producing gas shales and prospective shales. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

**EXHIBIT ES-1: UNITED STATES SHALE BASINS**




The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-size-fits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include $NO_x$, volatile organic compounds, particulate matter, $SO_2$, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

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# INTRODUCTION

Natural gas production from hydrocarbon-rich shale formations, known as "shale gas", is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring changes to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

This Primer endeavors to provide much of that information. It describes the importance of shale gas in meeting the future energy needs of the United States (U.S.), including its role in alternative energy strategies and reducing greenhouse gas (GHG) emissions. The Primer provides an overview of modern shale gas development, as well as a summary of federal, state, and local regulations applicable to the natural gas production industry, and describes environmental considerations related to shale gas development.

The Primer is intended to serve as a technical summary document, including geologic information on the shale gas basins in the U.S. and the methods of shale gas development. By providing an overview of the regulatory framework and the environmental considerations associated with shale gas development, it will also help facilitate the minimization and mitigation of adverse environmental impacts. By so doing, the Primer can serve as an instrument to facilitate informed public discussions and to support sound policy-making decisions by government.

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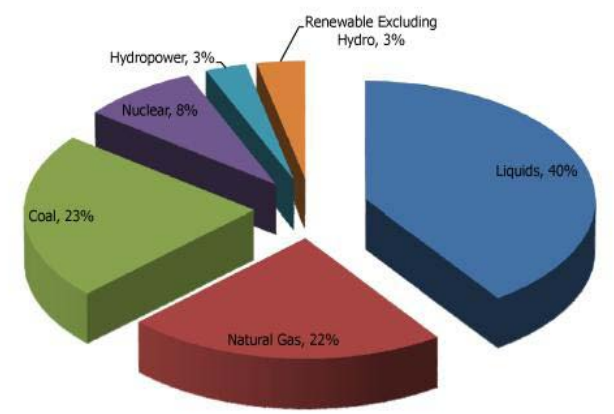
# THE IMPORTANCE OF SHALE GAS

## The Role of Natural Gas in the United States' Energy Portfolio

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total[1] (Exhibit 1[2]). The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

**EXHIBIT 1: UNITED STATES ENERGY CONSUMPTION BY FUEL (2007)**




*Source: EIA, 2008.*

The United States has abundant natural gas resources. The Energy Information Administration (EIA) estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place)[3,4]. Navigant Consulting estimates that technically recoverable unconventional gas (shale gas, tight sands, and coalbed natural gas) accounts for 60% of the onshore recoverable resource[5]. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years[6]. Note that historically, estimates of the size of the total recoverable resource have grown over time as knowledge of the resource has improved and recovery technology has advanced. Unconventional gas resources are a prime example of this trend.

### *What Is a Tcf?*

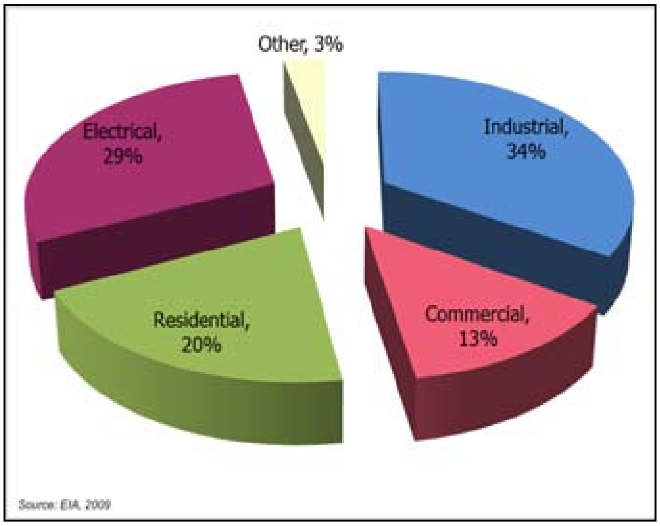
***Natural gas is generally priced and sold in units of a thousand cubic feet (Mcf, using the Roman numeral for one thousand). Units of a trillion cubic feet (tcf) are often used to measure large quantities, as in resources or reserves in the ground, or annual national energy consumption. A tcf is one billion Mcf and is enough natural gas to:***

- ***Heat 15 million homes for one year;***
- ***Generate 100 billion kilowatt-hours of electricity;***
- ***Fuel 12 million natural gas-fired vehicles for one year.***

Natural gas use is distributed across several sectors of the economy (Exhibit 2[7]). It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating[8]. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come[9].

Natural gas, due to its clean-burning nature and economical availability, has become a very popular fuel for the generation of electricity[10]. In the 1970s and 80s, the choice for the majority of electric utility generators was primarily coal or nuclear power; but, due to economic, environmental, technological, and regulatory changes, natural gas has become the fuel of choice for many new power plants. In 2007, natural gas was 39.1%[11] of electric industry productive capacity.

**EXHIBIT 2: NATURAL GAS USE BY SECTOR**




Natural gas is also the fuel of choice for a wide range of industries. It is a major fuel source for pulp and paper, metals, chemicals, petroleum refining, and food processing. These five industries alone account for almost three quarters of industrial natural gas use[12] and together employ four million people in the U.S.[13] Natural gas is also a feedstock for a variety of products, including plastics, chemicals, and fertilizers. For many products, there is no economically viable substitute for natural gas. Industrial use of natural gas accounted for 6.63 tcf of demand in 2007 and is expected to grow to 6.82 tcf by 2030.

However, natural gas is being consumed by the U.S. economy at a rate that exceeds domestic production and the gap is increasing[14]. Half of the natural gas consumed today is produced from wells drilled within the last 3.5 years[15]. Despite possessing a large resource endowment, the U.S. consumes natural gas at a rate requiring rapid replacement of reserves. It is estimated that the gap between demand and domestic supply will grow to nearly 9 tcf by the year 2025[16]. However, it is believed by many that unconventional natural gas resources such as shale gas can significantly alter that balance.

***Half of the natural gas consumed today is produced from wells drilled within the last 3.5 years.***

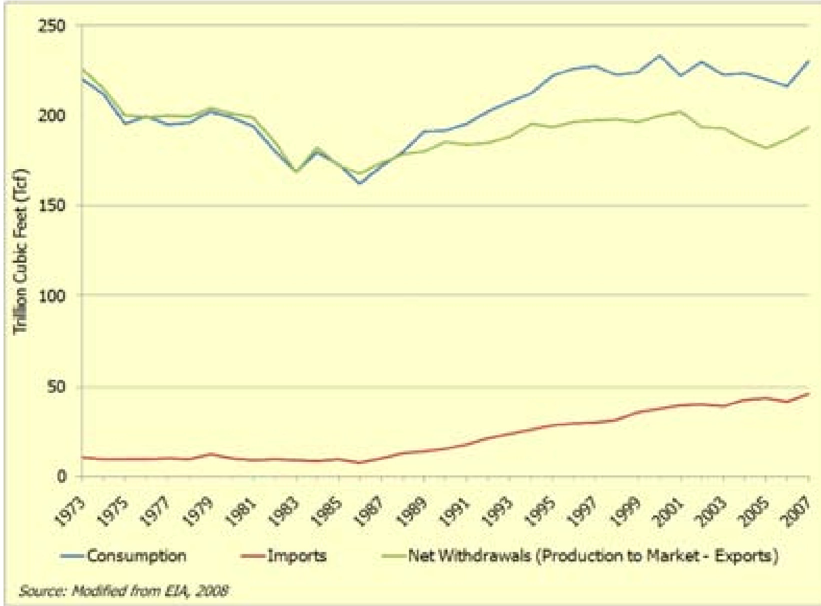
Exhibit 3[17] shows a comparison of production, consumption, and import trends for natural gas in the U.S. with demand increasingly exceeding conventional domestic production. Without domestic shale gas and other unconventional gas production, the gap between demand and domestic production will widen even more, leaving imports to fill the need. Worldwide consumption of natural gas is also increasing; therefore the U.S. can anticipate facing an increasingly competitive market for these imports.

This increased reliance on foreign sources of energy could pose at least two problems for the U.S.: 1) it would serve to decrease our energy security; and 2) it could create a multi-billion dollar outflow to foreign interests, thus making such funds unavailable for domestic investment.

## The Advantages of Natural Gas

In the 1800s and early 1900s, natural gas was mainly used to light streetlamps and the occasional house. However, with a vastly improved distribution network and advancements in technology, natural gas is now being used in many ways. One reason for the widespread use of natural gas is its versatility as a fuel. Its high British thermal unit (Btu) content and a well-developed infrastructure make it easy to use in a number of applications.

**EXHIBIT 3: COMPARISON OF PRODUCTION, CONSUMPTION AND IMPORT TRENDS FOR NATURAL GAS IN THE UNITED STATES**




Another factor that makes natural gas an attractive energy source is its reliability. Eighty-four percent of the natural gas consumed in the U.S. is produced in the U.S., and ninety-seven percent of the gas used in this country is produced in North America[18]. Thus, the supply of natural gas is not dependent on unstable foreign countries and the delivery system is less subject to interruption.

A key advantage of natural gas is that it is efficient and clean burning[19]. In fact, of all the fossil fuels, natural gas is by far the cleanest burning. It emits approximately half the carbon dioxide ($CO_2$) of coal along with low levels of other air pollutants[20]. The combustion byproducts of natural gas are mostly $CO_2$ and water vapor, the same compounds people exhale when breathing. Coal and oil are composed of much more complex organic molecules with greater nitrogen and sulfur content. Their combustion byproducts include larger quantities of $CO_2$, nitrogen oxides ($NO_x$), sulfur dioxide ($SO_2$) and particulate ash (Exhibit 4[21]). By comparison, the combustion of natural gas liberates very small amounts of $SO_2$ and $NO_x$, virtually no ash, and lower levels of $CO_2$, carbon monoxide (CO), and other hydrocarbons[22].

EXHIBIT 4: COMBUSTION EMISSIONS
**(POUNDS/BILLION BTU OF ENERGY INPUT)**

| Air Pollutant | Combusted Source | | |
|---|---|---|---|
| | Natural Gas | Oil | Coal |
| Carbon dioxide ($CO_2$) | 117,000 | 164,000 | 208,000 |
| Carbon monoxide (CO) | 40 | 33 | 208 |
| Nitrogen oxides ($NO_x$) | 92 | 448 | 457 |
| Sulfur dioxide ($SO_2$) | 0.6 | 1,122 | 2,591 |
| Particulates (PM) | 7.0 | 84 | 2,744 |
| Formaldehyde | 0.750 | 0.220 | 0.221 |
| Mercury (Hg) | 0.000 | 0.007 | 0.016 |

*Sources: EIA, 1998*

Because natural gas emits only half as much $CO_2$ as coal and approximately 30% less than fuel oil, it is generally considered to be central to energy plans focused on the reduction of GHG emissions[23]. According to the EIA in its report "Emissions of Greenhouse Gases in the United States 2006," 82.3% of GHG emissions in the U.S. in 2006 came from $CO_2$ as a direct result of fossil fuel combustion[24]. Since $CO_2$ makes up a large fraction of U.S. GHG emissions, increasing the role of natural gas in U.S. energy supply relative to other fossil fuels would result in lower GHG emissions.

***Of all the fossil fuels, natural gas is by far the cleanest burning.***

Although there is rapidly increasing momentum to reduce dependence on fossil fuels in the U.S. and elsewhere, the transition to sustainable renewable energy sources will no doubt require considerable time, effort and investment in order for these sources to become economical enough to supply a significant portion of the nation's energy consumption. Indeed, the EIA estimates that fossil fuels (oil, gas, and coal) will supply 82.1% of the nation's energy needs in 2030[25]. Since natural gas is the cleanest burning of the fossil fuels, an environmental benefit could be realized by shifting toward proportionately greater reliance on natural gas until such time as sources of alternative energy are more efficient, economical, and widely available.

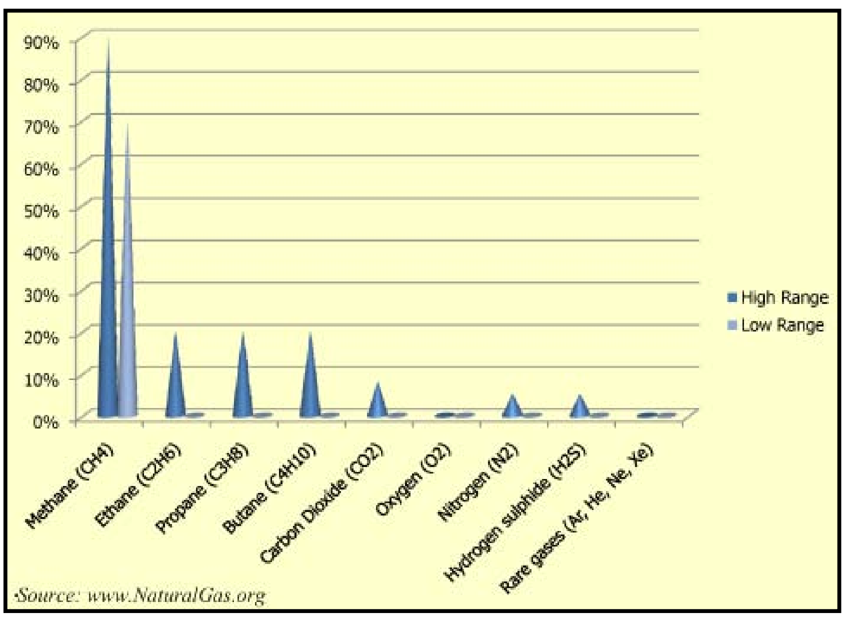
Additionally, the march towards sustainable renewable energy sources, such as wind and solar, requires that a supplemental energy source be available when weather conditions and electrical storage capacity prove challenging[26]. Such a backstop energy source must be widely available on near instantaneous demand. The availability of extensive natural gas transmission and distribution pipeline systems makes natural gas uniquely suitable for this role[27]. Thus, natural gas is an integral facet of moving forward with alternative energy options. With the current emphasis on the potential effects of air emissions on global climate change, air quality, and visibility, cleaner fuels like natural gas are an important part of our nation's energy future[28].

## Natural Gas Basics

Natural gas is a combination of hydrocarbon gases consisting primarily of methane ($CH_4$), and lesser percentages of butane, ethane, propane, and other gases[29,30]. It is odorless, colorless, and, when ignited, releases a significant amount of energy[31]. Exhibit 5[32] shows the typical compositional range of natural gas produced in the U.S.

Natural gas is found in rock formations (reservoirs) beneath the earth's surface; in some cases it may be associated with oil deposits. Exploration and production companies explore for these

**EXHIBIT 5: TYPICAL COMPOSITION OF NATURAL GAS**



deposits by using complex technologies to identify prospective drilling locations. Once extracted, the natural gas is processed to eliminate other gases, water, sand, and other impurities. Some hydrocarbon gases, such as butane and propane, are captured and separately marketed. Once it has been processed, the cleaned natural gas is distributed through a system of pipelines across thousands of miles[33]. It is through these pipelines that natural gas is transported to its endpoint for residential, commercial, and industrial use.

Natural gas is measured in either volumetric or energy units. As a gas, it is measured by the volume it displaces at standard temperatures and pressures, usually expressed in cubic feet. Gas companies generally measure natural gas in thousands of cubic feet (Mcf), millions of cubic feet (MMcf), or billions of cubic feet (bcf), and estimate resources such as original gas-in-place in trillions of cubic feet (tcf).

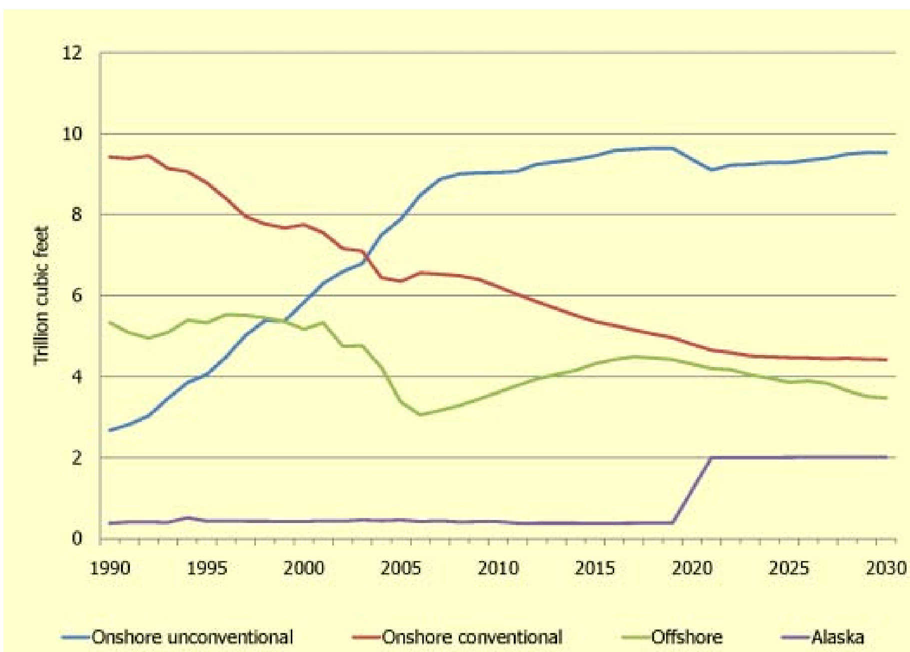
Calculating and tracking natural gas by volume is useful, but it can also be measured as a source of energy. Similar to other forms of energy, natural gas can be computed and presented in British thermal units (Btu). One Btu is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at normal pressure[34]. There are about 1,000 Btus in one cubic foot of natural gas delivered to the consumer[35]. Natural gas distribution companies typically measure the gas delivered to a residence in 'therms' for billing purposes[36]. A therm is equal to 100,000 Btus—approximately 100 cubic feet—of natural gas[37].

## Unconventional Gas

The U.S. increased its natural gas reserves by 6% from 1970 to 2006, producing approximately 725 tcf of gas during that period[38]. This increase is primarily a result of advancements in technology, resulting in an increase in economically recoverable reserves (reserves becoming proven) that were previously thought to be uneconomic[39].

In 2007, Texas, Wyoming, and Colorado were the states with the greatest additions to proved gas reserves for the year; these additions were from shale gas, tight sands, and coalbed methane, all of which are unconventional gas plays[40]. Similarly, the states of Texas (30%) and Wyoming (12%) had the greatest volume of proved gas

**EXHIBIT 6: NATURAL GAS PRODUCTION BY SOURCE (TCF/YEAR)**



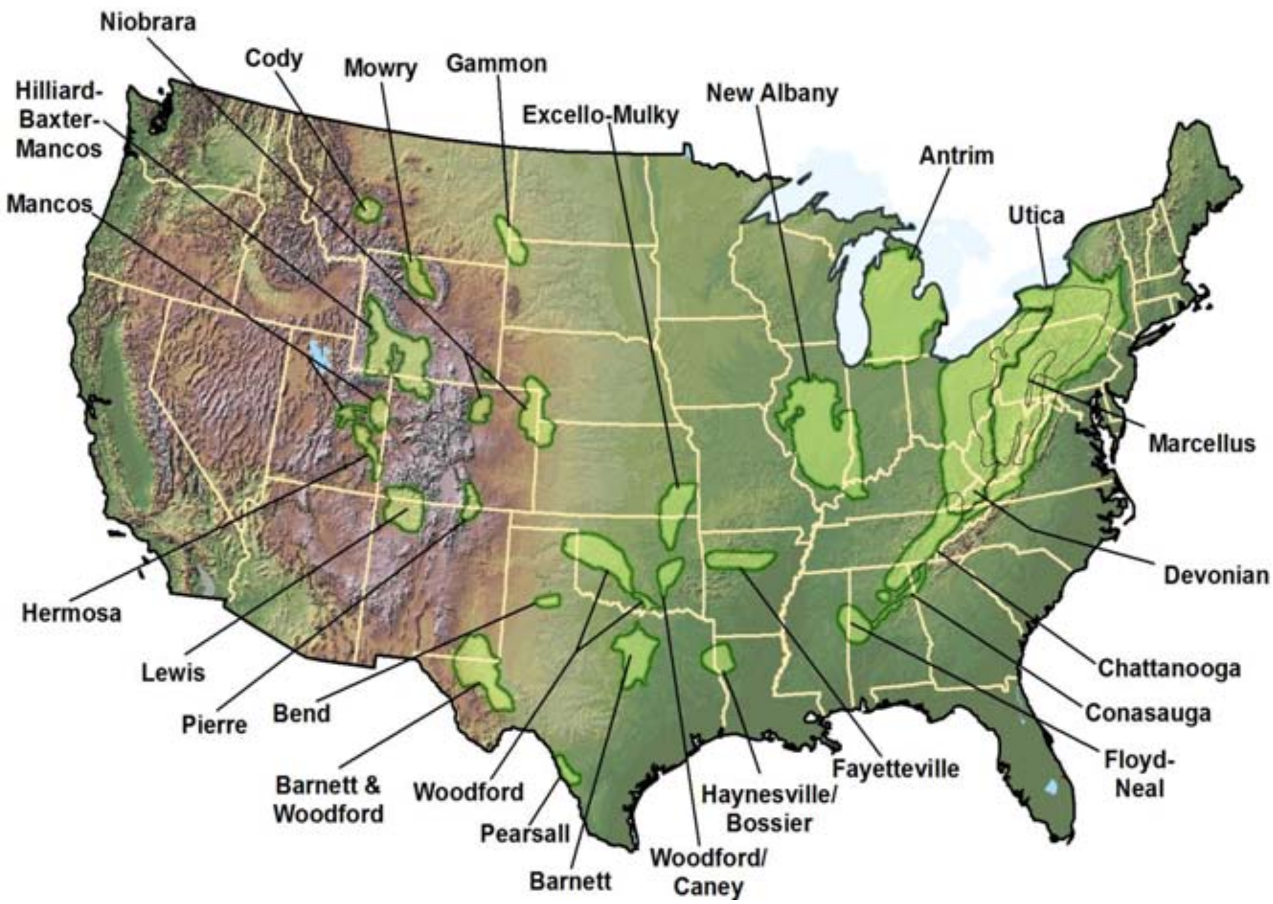

*Source: EIA, 2008*

reserves in the U.S. in 2007—again, both primarily as a result of developing unconventional natural gas plays[41].

***Unconventional production now accounts for 46% of the total U.S. production.***

Overall, unconventional natural gas is anticipated to become an ever-increasing portion of the U.S. proved reserves, while conventional gas reserves are declining[42]. Over the last decade, production from unconventional sources has increased almost 65%, from 5.4 trillion cubic feet per year (tcf/yr) in 1998 to 8.9 tcf/yr in 2007 (Exhibit 6). This means unconventional production now accounts for 46% of the total U.S. production[43].

**EXHIBIT 7: UNITED STATES SHALE GAS BASINS**

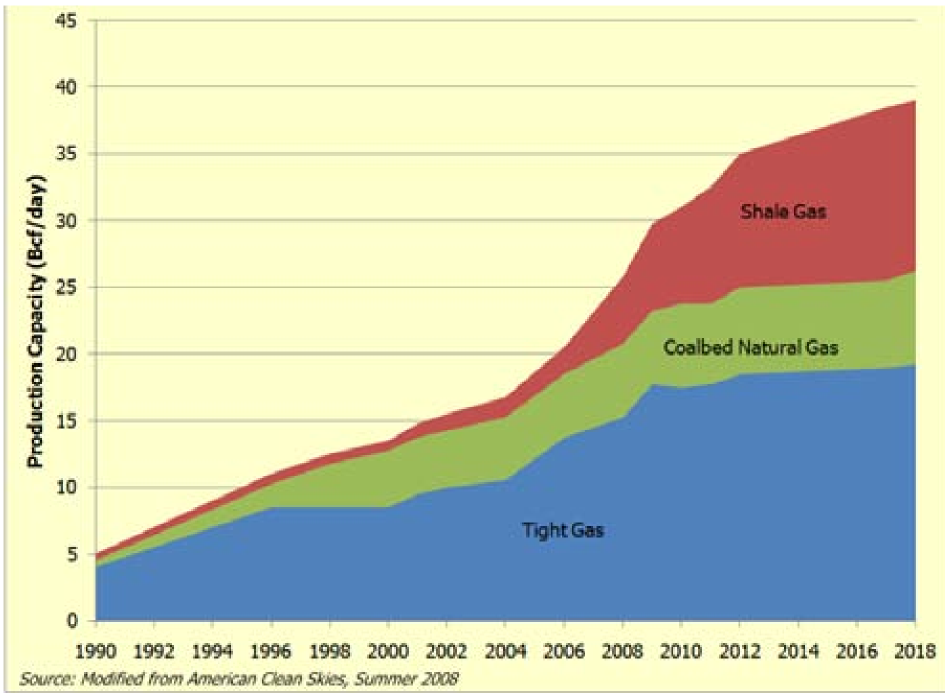



*Source: ALL Consulting, Modified from USGS & other sources*

## The Role of Shale Gas in Unconventional Gas

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas (Exhibit 7[44]). Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 states[45]. Improved drilling and fracturing technologies have contributed considerably to the economic potential of shale gas. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook. Exhibit 8[46] shows the projected contribution of shale gas to the overall unconventional gas production in the U.S. in bcf/day.

**EXHIBIT 8: UNITED STATES UNCONVENTIONAL GAS OUTLOOK (BCF/DAY)**



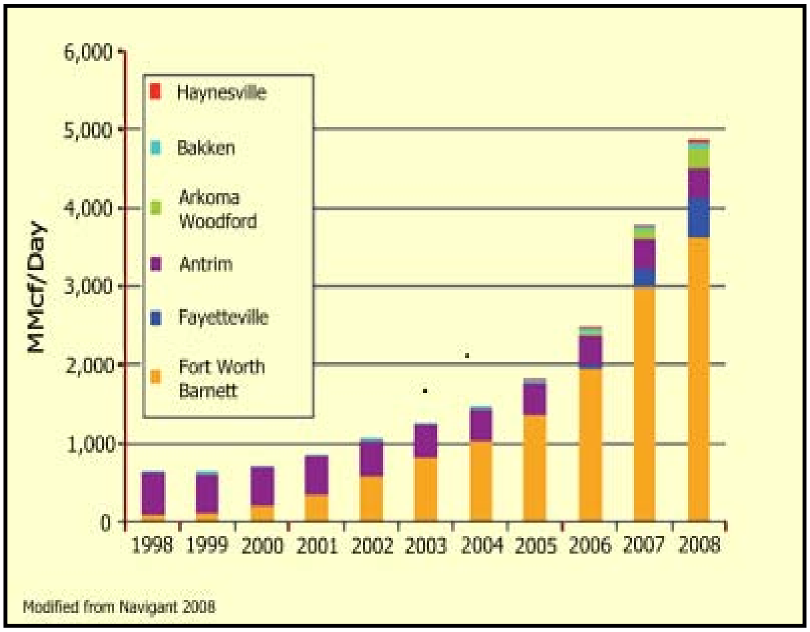

Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Advances in the pre-existing technologies of directional drilling and hydraulic fracturing set the stage for today's horizontal drilling and fracturing techniques, without which many of the unconventional natural gas plays would not be economical. As recently as the late 1990s, only 40 drilling rigs (6% of total active rigs in the U.S.) in the U.S. were capable of onshore horizontal drilling; that number grew to 519 rigs (28% of total active rigs in the U.S.) by May 2008[47].

It has been suggested that the rapid growth of unconventional natural gas plays has not been captured by recent resource estimates compiled by the EIA and that, therefore, their resource estimates do not accurately reflect the contribution of shale gas[48]. Since 1998, annual production has consistently exceeded the EIA's forecasts of unconventional gas production. A great deal of this increase is attributable to shale gas production, particularly from the Barnett Shale in Texas. The potential for most other shale gas plays in the U.S. is just emerging. Taking this into consideration, Navigant, adding their own analysis of shale gas resources to other national resource estimates, has estimated that U.S. total natural gas resources (proved plus unproved technically recoverable) are 1,680 tcf to 2,247 tcf, or 87 to 116 years of production at 2007 U.S. production levels. This compares with EIA's national

***Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices.***

resource estimate of 1,744 tcf, which is within the Navigant range. Navigant has estimated that shale gas comprises 28% or more of total estimated technically recoverable gas resources in the U.S.[49]. Exhibit 9[50] depicts the daily production (in MMcf/day) from each of the currently active shale gas plays.

**EXHIBIT 9: TRENDS IN SHALE GAS PRODUCTION (MMCF/DAY)**




As with most resource estimates, especially emerging resources such as unconventional natural gas, these estimates are likely to change over time. In addition, there are a variety of organizations making resource and future production estimates for shale gas. These analyses use different assumptions, data, and methodologies. Therefore, one may come across a wide range of numbers for projected shale gas recovery, both nationally and by basin. These shale gas resource estimates are likely to change as new information, additional experience, and advances in technology become available.

***Shale gas resource estimates are likely to change as new information, additional experience, and advances in technology become available.***

Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs[51]. The total recoverable gas resources from 4 emerging shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf[52]. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. An additional benefit of shale gas plays is that many exist in areas previously developed for natural gas production and, therefore, much of the necessary pipeline infrastructure is already in place. Many of these areas are also proximal to the nation's population centers thus potentially facilitating transportation to consumers. However, additional pipelines will have to be built to access development in areas that have not seen gas production before[53].

## Looking Forward

Considering natural gas's clean-burning nature, the nation's domestic natural gas resources, and the presence of supporting infrastructure, the development of domestic shale gas reserves will be an important component of the U.S.'s energy portfolio for many years. Recent successes in a variety of geologic basins have created the opportunity for shale gas to be a strategic part of the nation's energy and economic growth[54].

***Recent successes and improvements in a variety of geologic basins have created the opportunity for shale gas to be a strategic part of the nation's energy and economic growth.***

The Environmental Considerations section of this Primer describes how improvements in horizontal drilling and hydraulic fracturing technologies have opened the door to the economic recovery of shale gas. It also discusses additional practices that have allowed development of areas that might previously have been inaccessible due to environmental constraints or restrictions on disturbances in both urban and rural settings. By using horizontal drilling, operators have been able to reduce the extent of surface impact commonly associated with multiple vertical wells drilled from multiple well pads; equivalent well coverage can be achieved through drilling fewer horizontal wells from a single well pad. This can result in a significant reduction in surface disturbances: fewer well pads, fewer roads, reduced traffic, fewer pipelines, and fewer surface facilities. In urban settings, this can mean less impact on nearby populations and businesses. In rural settings, this can mean fewer consequences for wildlife habitats, agricultural resources, and surface water bodies.

Other practices that are now commonly used for drilling, particularly in urban settings, include: the use of sound walls and blankets to reduce noise, the use of directional or shielded lighting to reduce nighttime disturbance to nearby residences and businesses, the use of pipelines to transport water resulting in reduced truck traffic, and the use of solar-powered telemetry devices to monitor gas production resulting in reduced personnel visits to well sites. Such practices are used in specific locations or situations that call for them, and are not appropriate everywhere, but where needed, they provide opportunities for safe, environmentally sound development that may not have been possible without them.

These technologies and practices, along with the increasing gas prices of the last few years, have provided the means by which shale gas can be economically recovered. Improvements in reducing the overall footprint and level of disturbance from drilling and completion activities have provided the industry with the methods for moving forward with development in new areas that were previously inaccessible.

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# SHALE GAS DEVELOPMENT IN THE UNITED STATES

Shale formations across the U.S. have been developed to produce natural gas in small but continuous volumes since the earliest years of gas development. The first producing gas well in the U.S. was completed in 1821 in Devonian-aged shale near the town of Fredonia, New York[55]. The natural gas from this first well was used by town residents for lighting[56]. Early supplies of natural gas were derived from shallow gas wells that were not complicated to drill and from natural gas seeps[57]. The shallow wells and seeps were capable of producing small amounts of natural gas that were used for illuminating city streets and households[58]. These early gas wells played a key part in bringing illumination to the cities and towns of the eastern U.S.[59].

***The first producing gas well in the U.S. was completed in 1821 in Devonian-aged shale near the town of Fredonia, New York.***

Other shale gas wells followed the Fredonia well with the first field-scale development of shale gas from the Ohio Shale in the Big Sandy Field of Kentucky during the 1920s[60]. The Big Sandy Field has recently experienced a renewed growth and currently is a 3,000-square-mile play encompassing five counties[61]. By the 1930s, gas from the Antrim Shale in Michigan had experienced moderate development; however, it was not until the 1980s that development began to expand rapidly to the point that it has now reached nearly 9,000 wells[62]. It was also during the 1980s that one of the nation's most active natural gas plays initially kicked off in the area around Fort Worth, Texas[63]. The play was the Barnett Shale, and its success grabbed the industry's attention. Large-scale hydraulic fracturing, a process first developed in Texas in the 1950s, was first used in the Barnett in 1986; likewise, the first Barnett horizontal well was drilled in 1992[64]. Through continued improvements in the techniques and technology of hydraulic fracturing, development of the Barnett Shale has accelerated[65]. In the ensuing two decades, the science of shale gas extraction has matured into a sophisticated process that utilizes horizontal drilling and sequenced, multi-stage hydraulic fracturing technologies. As the Barnett Shale play has matured, natural gas producers have been looking to extrapolate the lessons learned in the Barnett to the other shale gas formations present across the U.S. and Canada[66].

In addition to the Barnett Play, a second shale play with greater oil production has also been advancing techniques related to horizontal wells and hydraulic fracturing. The Bakken Shale of the Williston Basin of Montana and North Dakota has seen a similar growth rate to the Barnett. The Bakken is another technical play in which the development of this unconventional resource has benefitted from the technological advances in horizontal wells and hydraulic fracturing[67]. In April 2008, the United States Geological Survey (USGS) released an updated assessment of the undiscovered technically recoverable reserves for this shale play estimating there are 3.65 billion barrels (bbls) of oil, 1.85 tcf of associated natural gas, and 148 million bbls of natural gas liquids in the play[68].

The combination of sequenced hydraulic fracture treatments and horizontal well completions has been crucial in facilitating the expansion of shale gas development. Prior to the successful application of these two technologies in the Barnett Shale, shale gas resources in many basins had been overlooked because production was not viewed as economically feasible[69]. The low natural permeability of shale has been the limiting factor to the production of shale gas resources because it only allows minor volumes of gas to flow naturally to a wellbore[70]. The characteristic of low-matrix permeability represents a key difference between shale and other gas reservoirs. For gas shales to be economically produced, these restrictions must be overcome[71]. The combination of reduced economics and low permeability of gas shale formations historically caused operators to bypass these formations and focus on other resources[72].

## Shale Gas – Geology

Shale gas is natural gas produced from shale formations that typically function as both the reservoir and source for the natural gas. In terms of its chemical makeup, shale gas is typically a dry gas primarily composed of methane (90% or more methane), but some formations do produce wet gas. The Antrim and New Albany formations have typically produced water and gas[73]. Gas shales are organic-rich shale formations that were previously regarded only as source rocks and seals for gas accumulating in the stratigraphically-associated sandstone and carbonate reservoirs of traditional onshore gas development[74]. Shale is a sedimentary rock that is predominantly comprised of consolidated clay-sized particles. Shales are deposited as mud in low-energy depositional environments such as tidal flats and deep water basins where the fine-grained clay particles fall out of suspension in these quiet waters. During the deposition of these very fine-grained sediments, there can also be deposition of organic matter in the form of algae-, plant-, and animal-derived organic debris[75]. The naturally tabular clay grains tend to lie flat as the sediments accumulate and subsequently become compacted as a result of additional sediment deposition. This results in mud with thin laminar bedding that lithifies (solidifies) into thinly layered shale rock. The very fine sheet-like clay mineral grains and laminated layers of sediment result in a rock that has limited horizontal permeability and extremely limited vertical permeability. Typical unfractured shales have matrix permeabilities on the order of 0.01 to 0.00001 millidarcies[76]. This low permeability means that gas trapped in shale cannot move easily within the rock except over geologic expanses of time (millions of years).

**EXHIBIT 10: MARCELLUS SHALE OUTCROP**

*Source: ALL Consulting, 2008*

The natural layering and fracturing of shales can be seen in outcrop. Exhibit 10 shows a typical shale outcrop which reveals the natural bedding planes, or layers, of the shale and near-vertical natural fractures that can cut across the naturally horizontal bedding planes. Although the vertical fractures shown in this picture are naturally occurring, artificial fractures induced by hydraulic fracture stimulation in the deep subsurface reservoir rock would have a similar appearance.

The low permeability of shale causes it to be classified as an unconventional reservoir for gas (or in some cases, oil) production. These low permeability, often organic-rich units are also thought to be the source beds for much of the hydrocarbons produced in these basins[77]. Gas reservoirs are classified as conventional or unconventional for the following reasons:

1. **Conventional reservoirs** – Wells in conventional gas reservoirs produce from sands and carbonates (limestones and dolomites) that contain the gas in interconnected pore spaces that allow flow to the wellbore. Much like a kitchen sponge, the gas in the pores can move from one pore to another through smaller pore-throats that create permeable flow through the reservoir. In conventional natural gas reservoirs, the gas is often sourced from organic-rich shales proximal to the more porous and permeable sandstone or carbonate.
2. **Unconventional reservoirs** – Wells in unconventional reservoirs produce from low permeability (tight) formations such as tight sands and carbonates, coal, and shale. In unconventional gas reservoirs, the gas is often sourced from the reservoir rock itself (tight gas sandstone and carbonates are an exception). Because of the low permeability of these formations, it is typically necessary to stimulate the reservoir to create additional permeability. Hydraulic fracturing of a reservoir is the preferred stimulation method for gas shales. Differences between the three basic types of unconventional reservoirs include:
    1. **Tight Gas –** Wells produce from regional low-porosity sandstones and carbonate reservoirs. The natural gas is sourced (formed) outside the reservoir and migrates into the reservoir over time (millions of years)[78]. Many of these wells are drilled horizontally and most are hydraulically fractured to enhance production.
    2. **Coal Bed Natural Gas** (CBNG) – Wells produce from the coal seams which act as source and reservoir of the natural gas[79]. Wells frequently produce water as well as natural gas. Natural gas can be sourced by thermogenic alterations of coal or by biogenic action of indigenous microbes on the coal. There are some horizontally drilled CBNG wells and some that receive hydraulic fracturing treatments. However, some CBNG reservoirs are also underground sources of drinking water and as such there are restrictions on hydraulic fracturing. CBNG wells are mostly shallow as the coal matrix does not have the strength to maintain porosity under the pressure of significant overburden thickness.
    3. **Shale Gas** – Wells produce from low permeability shale formations that are also the source for the natural gas. The natural gas volumes can be stored in a local macro-porosity system (fracture porosity) within the shale, or within the micro-pores of the shale[80], or it can be adsorbed onto minerals or organic matter within the shale[81]. Wells may be drilled either vertically or horizontally and most are hydraulically fractured to stimulate production. Shale gas wells can be similar to other conventional and unconventional wells in terms of depth, production rate, and drilling.

## Sources of Natural Gas

Shale gas is both created and stored within the shale bed. Natural gas (methane) is generated from the organic matter that is deposited with and present in the shale matrix.

In order for a shale to have economic quantities of gas it must be a capable source rock. The potential of a shale formation to contain economic quantities of gas can be evaluated by identifying specific source rock characteristics such as total organic carbon (TOC), thermal maturity, and kerogen analysis. Together, these factors can be used to predict the likelihood of the prospective shale to produce economically viable volumes of natural gas. A number of wells may need to be analyzed in order to sufficiently characterize the potential of a shale formation, particularly if the geologic basin is large and there are variations in the target shale zone.

## Shale Gas in the United States

Shale gas is present across much of the lower 48 States. Exhibit 7 shows the approximate locations of current producing gas shales and prospective shales. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. The following discussion provides a summary of basic information regarding these shale gas plays.

Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique challenges. For example, the Antrim and New Albany Shales are shallower shales that produce significant volumes of formation water unlike most of the other gas shales. Development of the Fayetteville Shale is occurring in rural areas of north central Arkansas, while development of the Barnett Shale is focused in the area of Forth Worth, Texas, in an urban and suburban environment.

### Key Gas Resource Terms

***Proved Reserves**: That portion of recoverable resources that is demonstrated by actual production or conclusive formation tests to be technically, economically, and legally producible under existing economic and operating conditions.*

***Technically Recoverable Resources**: The total amount of resource, discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.*

***Original Gas-In-Place**: The entire volume of gas contained in the reservoir, regardless of the ability to produce it.*

As new technologies are developed and refined, shale gas plays once believed to have limited economic viability are now being re-evaluated. Exhibit 11 summarizes the key characteristics of the most active shale gas plays across the U.S. This exhibit supplies data related to the character of the shale and also provides a means to compare some of the key characteristics that are used to evaluate the different gas shale basins. Note that estimates of the shale gas resource, especially the portion that is technically recoverable, are likely to increase over time as new data become available from additional drilling, as experience is gained in producing shale gas, as understanding of the resource characteristics increases, and as recovery technologies improve.

| **EXHIBIT 11: COMPARISON OF DATA FOR THE GAS SHALES IN THE UNITED STATES** | | | | | | | |
|---|---|---|---|---|---|---|---|
| Gas Shale Basin | Barnett | Fayetteville | Haynesville | Marcellus | Woodford | Antrim | New Albany |
| Estimated Basin Area, square miles | 5,000 | 9,000 | 9,000 | 95,000 | 11,000 | 12,000 | 43,500 |
| Depth, ft | 6, 500 - 8,500[82] | 1,000 - 7,000[83] | 10,500 - 13,500[84] | 4,000 - 8,500[85] | 6,000 - 11,000[86] | 600 - 2,200[87] | 500 - 2,000[88] |
| Net Thickness, ft | 100 - 600[89] | 20 - 200[90] | 200[91] - 300[92] | 50 - 200[93] | 120 - 220[94] | 70 - 120[95] | 50 - 100[96] |
| Depth to Base of Treatable Water#, ft | ~1200 | ~500[97] | ~400 | ~850 | ~400 | ~300 | ~400 |
| Rock Column Thickness between Top of Pay and Bottom of Treatable Water, ft | 5,300 - 7,300 | 500 - 6,500 | 10,100 - 13,100 | 2,125 - 7650 | 5,600 - 10,600 | 300 - 1,900 | 100 - 1,600 |
| Total Organic Carbon, % | 4.5[98] | 4.0 - 9.8[99] | 0.5 - 4.0[100] | 3 - 12[101] | 1 - 14[102] | 1 - 20[103] | 1 - 25[104] |
| Total Porosity, % | 4 - 5[105] | 2 - 8[106] | 8 - 9[107] | 10[108] | 3 - 9[109] | 9[110] | 10 - 14[111] |
| Gas Content, scf/ton | 300 - 350[112] | 60 - 220[113] | 100 - 330[114] | 60 - 100[115] | 200 - 300[116] | 40 - 100[117] | 40 - 80[118] |
| Water Production, Barrels water/day | N/A | N/A | N/A | N/A | N/A | 5 - 500[119] | 5 - 500[120] |
| Well spacing, acres | 60 - 160[121] | 80 - 160 | 40 - 560[122] | 40 - 160[123] | 640[124] | 40 - 160[125] | 80[126] |
| Original Gas-In-Place, tcf[127] | 327 | 52 | 717 | 1,500 | 23 | 76 | 160 |
| Technically Recoverable Resources, tcf[128] | 44 | 41.6 | 251 | 262 | 11.4 | 20 | 19.2 |

**NOTE: Information presented in this table, such as Original Gas-in-Place and Technically Recoverable Resources, is presented for general comparative purposes only. The numbers provided are based on the sources shown and this research did not include a resource evaluation. Rather, publically available data was obtained from a variety of sources and is presented for general characterization and comparison. Resource estimates for any basin may vary greatly depending on individual company experience, data available at the time the estimate was performed, and other factors. Furthermore, these estimates are likely to change as production methods and technologies improve.**

Mcf = thousands of cubic feet of gas
scf = standard cubic feet of gas
tcf = trillions of cubic feet of gas
# = For the Depth to base of treatable water data, the data was based on depth data from state oil and gas agencies and state geological survey data.
N/A = Data not available

## *The Barnett Shale*

The Barnett Shale is located in the Fort Worth Basin of north-central Texas. It is a Mississippian-age shale occurring at a depth of 6,500 feet to 8,500 feet (Exhibit 11 and Exhibit 13[131]) and is bounded by limestone formations above (Marble Falls Limestone) and below (Chappel Limestone) (Exhibit 12).

With over 10,000 wells drilled to date, the Barnett Shale is the most prominent shale gas play in the U.S.[132]. It has been a showcase for modern tight-reservoir development typical of gas shales in the U.S.[133]. The development of the Barnett Shale has been a proving ground for combining the technologies of horizontal drilling and large-volume hydraulic fracture treatments. Drilling operations continue expanding the play boundaries outward; at the same time, operations have turned towards infill drilling to increase the amount of gas recovered[134]. Horizontal well completions in the Barnett are occurring at well spacing ranging from 60 to 160 acres per well (Exhibit 11).

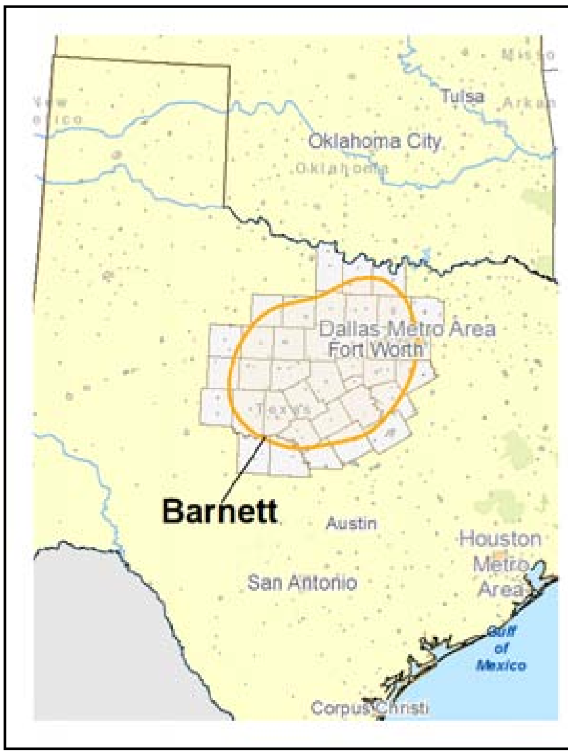
The Barnett Shale covers an area of about 5,000 square miles with an approximate thickness ranging from 100 feet (ft) to more than 600 ft (Exhibit 11). The original gas-in-place estimate for the Barnett Shale is 327 tcf with estimated technically recoverable resources of 44 tcf (Exhibit 11). The gas content is the highest among the major shale plays, ranging from 300 standard cubic feet per ton (scf/ton) to 350 scf/ton of rock (Exhibit 11).

**EXHIBIT 12: STRATIGRAPHY OF THE BARNETT SHALE**

| Period | | | Group/Unit |
|---|---|---|---|
| Permian | | Leonardian | Clear Fork Grp |
| | | | Wichita Grp |
| | | Wolfcampian | Cisco Grp |
| Pennsylvanian | | Virgilian | |
| | | Missourian | Canyon Grp |
| | | Desmoinesian | Strawn Grp |
| | | Atokan | Bend Grp |
| | | Morrowan | Marble Falls Limestone |
| Mississippian | | Chesterian - Meramecian | Barnett Shale |
| | | Osagean | |
| | | | Chappel Limestone |
| Ordovician | | | Viola Limestone |
| | | Canadian | Simpson Grp Ellenburger Grp |

*Source: Hayden and Pursell, 2005[129]*
*AAPG, 1987[130]*

**EXHIBIT 13: BARNETT SHALE IN THE FORT WORTH BASIN**




*Source: ALL Consulting, 2009*

### *The Fayetteville Shale*

The Fayetteville Shale is situated in the Arkoma Basin of northern Arkansas and eastern Oklahoma over a depth range of 1,000 ft to 7,000 ft (Exhibit 15[135] and Exhibit 11). The Fayetteville Shale is a Mississippian-age shale bounded by limestone (Pitkin Limestone) above and sandstone (Batesville Sandstone) below (Exhibit 14).

Development of the Fayetteville began in the early 2000s as gas companies that had experienced success in the Barnett Shale of the Fort Worth Basin identified parallels between it and the Mississippian-aged Fayetteville Shale in terms of age and geologic character[136]. Lessons learned from the horizontal drilling and hydraulic fracturing techniques employed in the Barnett, when adapted to development of the Fayetteville Shale, made this play economical[137]. Between 2004 and 2007 the number of gas wells drilled annually in the Fayetteville shale jumped from 13 to more than 600, and gas production for the shale increased from just over 100 MMcf/yr to approximately 88.85 bcf/yr[138]. With over 1,000 wells in production to date, the Fayetteville Shale is currently on its way to becoming one of the most active plays in the U.S.[139].

The area of the Fayetteville Shale play is nearly double that of the Barnett Shale at 9,000 square miles, with well spacing ranging from 80 to 160 acres per well, and pay zone thickness averaging between 20 ft and 200 ft (Exhibit 11). The gas content for the Fayetteville Shale has been measured at 60 to 220 scf/ton, which is less than the 300 to 350 scf/ton gas content of the Barnett. The lower gas content of the Fayetteville, as compared to the Barnett, results in lower estimates of the original gas-in-place and technically recoverable resources: 52 tcf and 41.6 tcf respectively (Exhibit 11).

**EXHIBIT 14: STRATIGRAPHY OF THE FAYETTEVILLE SHALE**

| Period | | Group/Unit | |
|---|---|---|---|
| Carboniferous | Pennsylvanian | Atoka | |
| | | Bloyd | |
| | | Hale | Prairie Grove |
| | | | Cane Hill |
| | Mississippian | (IMO) | |
| | | Pitkin | |
| | | Fayetteville | |
| | | Batesville | |
| | | Moorefield | |
| | | Boone | |

*Source: Hillwood, 2007[140]*

**EXHIBIT 15: FAYETTEVILLE SHALE IN THE ARKOMA BASIN**


*Source: ALL Consulting, 2009*

## *The Haynesville Shale*

The Haynesville Shale (also known as the Haynesville/Bossier) is situated in the North Louisiana Salt Basin in northern Louisiana and eastern Texas with depths ranging from 10,500 ft to 13,500 ft (Exhibit 17[141] and Exhibit 11). The Haynesville is an Upper Jurassic-age shale bounded by sandstone (Cotton Valley Group) above and limestone (Smackover Formation) below (Exhibit 16).

In 2007, after several years of drilling and testing, the Haynesville Shale made headlines as a potentially significant gas reserve, although the full extent of the play will only be known after several more years of development are completed[142].

The Haynesville Shale covers an area of approximately 9,000 square miles with an average thickness of 200 ft to 300 ft (Exhibit 11). The thickness and areal extent of the Haynesville has allowed operators to evaluate a wider variety of spacing intervals ranging from 40 to 560 acres per well (Exhibit 11). Gas content estimates for the play are 100 scf/ton to 330 scf/ton. The Haynesville formation has the potential to become a significant shale gas resource for the U.S. with original gas-in-place estimates of 717 tcf and technically recoverable resources estimated at 251 tcf (Exhibit 11).

**EXHIBIT 16: STRATIGRAPHY OF THE HAYNESVILLE SHALE**

| Period | | Group/Unit |
|---|---|---|
| Cretaceous | | Navarro |
| | | Taylor |
| | | Austin |
| | | Eagle Ford |
| | | Tuscaloosa |
| | | Washita |
| | | Fredericksburg |
| | | Trinity Group |
| | | Nuevo Leon |
| Jurassic | Upper | Cotton Valley Group |
| | | Haynesville |
| | | Smackover |
| | | Norphlet |
| | Middle | Louann |
| | Lower | Werner |
| Triassic | Upper | Eagle Mills |

*Source: Johnson et al, 2000*[143]

**EXHIBIT 17: HAYNESVILLE SHALE IN THE TEXAS & LOUISIANA BASIN**


*Source: ALL Consulting, 2009*

## *The Marcellus Shale*

The Marcellus Shale is the most expansive shale gas play, spanning six states in the northeastern U.S. (Exhibit 19[144]). The estimated depth of production for the Marcellus is between 4,000 ft and 8,500 ft (Exhibit 11). The Marcellus Shale is a Middle Devonian-age shale bounded by shale (Hamilton Group) above and limestone (Tristates Group) below (Exhibit 18).

Following an increase in gas prices, triggered by the Natural Gas Policy Act (NGPA) of 1978, Devonian shale gas development rose in the early- to mid-1980s in the northeast, but decreasing gas prices resulted in uneconomical wells and declining production through the 1990s[145]. In 2003, Range Resources Corporation drilled the first economically producing wells into the Marcellus formation in Pennsylvania using horizontal drilling and hydraulic fracturing techniques similar to those used in the Barnett Shale formation of Texas[146]. Range Resources began producing this formation in 2005. As of September 2008, there were a total of 518 wells permitted in Pennsylvania in the Marcellus shale and 277 of the approved wells had been drilled[147].

The Marcellus Shale covers an area of 95,000 square miles at an average thickness of 50 ft to 200 ft (Exhibit 11). While the Marcellus is lower in relative gas content at 60 scf/ton to 100 scf/ton, the much larger area of this play compared to the other shale gas plays results in a higher original gas-in-place estimate of up to 1,500 tcf (Exhibit 11).

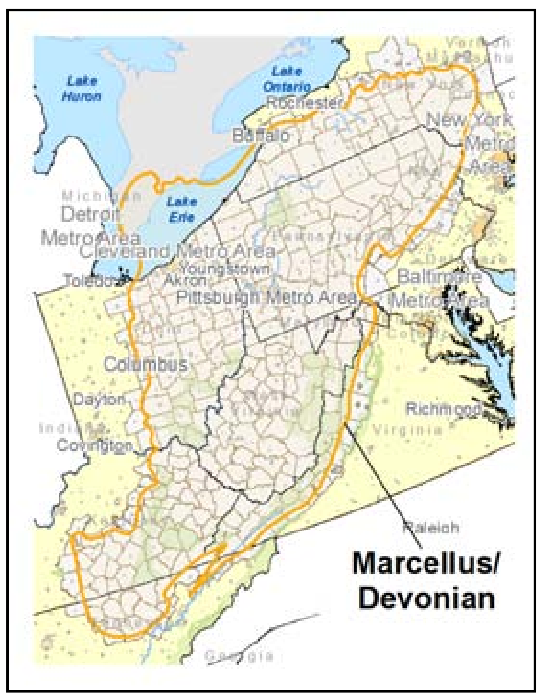
At an average well spacing in the Marcellus is 40 to 160 acres per well (Exhibit 11). The data in Exhibit 11 show technically recoverable resources for the formation to be 262 tcf, although much like the Haynesville, the play's potential estimates are frequently being revised upward due to its early stage of development.

**EXHIBIT 18: STRATIGRAPHY OF THE MARCELLUS SHALE**

| Period | | Group/Unit | |
|---|---|---|---|
| Penn | | Pottsville | |
| Miss | | Pocono | |
| Devonian | Upper | Conewango | |
| | | Conneaut | |
| | | Canadaway | |
| | | West Falls | |
| | | Sonyea | |
| | | Genesee | |
| | Middle | Tully | |
| | | Hamilton Group | Moscow |
| | | | Ludlowville |
| | | | Skaneateles |
| | | | Marcellus |
| | | Onandaga | |
| | Lower | Tristates | |
| | | Helderberg | |

*Source: Arthur et al, 2008*[148]

**EXHIBIT 19: MARCELLUS SHALE IN THE APPALACHIAN BASIN**




*Source: ALL Consulting, 2009*

### *The Woodford Shale*

Located in south-central Oklahoma, the Woodford Shale ranges in depth from 6,000 ft to 11,000 ft (Exhibit 21[149] and Exhibit 11). This formation is a Devonian-age shale bounded by limestone (Osage Lime) above and undifferentiated strata below (Exhibit 20).

Recent natural gas production in the Woodford Shale began in 2003 and 2004 with vertical well completions only[150]. However, horizontal drilling has been adopted in the Woodford, as in other shale gas plays, due to its success in the Barnett Shale[151].

The Woodford Shale play encompasses an area of nearly 11,000 square miles (Exhibit 11). The Woodford play is in an early stage of development and is occurring at a spacing interval of 640 acres per well (Exhibit 11). The average thickness of the Woodford Shale varies from 120 ft to 220 ft across the play (Exhibit 11).

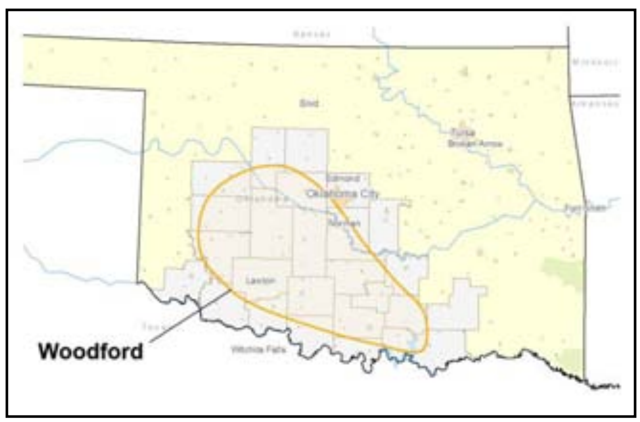
Gas content in the Woodford Shale is higher on average than some of the other shale gas plays at 200 scf/ton to 300 scf/ton (Exhibit 11). The original gas-in-place estimate for the Woodford Shale is similar to the Fayetteville Shale at 23 tcf while the technically recoverable resources are 11.4 tcf (Exhibit 11).

**EXHIBIT 20: STRATIGRAPHY OF THE WOODFORD SHALE**

<table>
<tr><th colspan="2">Period</th><th colspan="2">Group/Unit</th></tr>
<tr><td rowspan="8">Permian</td><td>Ochoan</td><td colspan="2" rowspan="2">Cloyd Chief Fm</td></tr>
<tr><td rowspan="3">Guadalupian</td></tr>
<tr><td colspan="2">White Horse Grp</td></tr>
<tr><td colspan="2">El Reno Grp</td></tr>
<tr><td>Leonardian</td><td colspan="2">Enid Grp</td></tr>
<tr><td rowspan="3">Wolfcampian</td><td colspan="2">Chase Grp</td></tr>
<tr><td colspan="2">Council Grove Grp</td></tr>
<tr><td colspan="2">Admire Grp</td></tr>
<tr><td rowspan="2">Penn.</td><td>Atokan</td><td colspan="2">Atoka Grp</td></tr>
<tr><td>Morrowan</td><td colspan="2">Morrow Grp</td></tr>
<tr><td rowspan="4">Mississippian</td><td>Chesterian</td><td colspan="2">Chester Grp</td></tr>
<tr><td>Meramecian</td><td rowspan="3">Miss Lime</td><td>Meramec Lime</td></tr>
<tr><td>Osagean</td><td rowspan="2">Osage Lime</td></tr>
<tr><td rowspan="2">Kinderhookian</td></tr>
<tr><td rowspan="4">Devonian</td><td colspan="2">Woodford Shale</td></tr>
<tr><td>Upper</td><td colspan="2" rowspan="2">Undifferentiated</td></tr>
<tr><td>Middle</td></tr>
<tr><td>Lower</td><td>Hunton Grp</td><td>Haragan Fm Henryhouse Fm</td></tr>
</table>

*Source: Cardott, 2007[152] AAPG, 1983[153]*

**EXHIBIT 21: WOODFORD SHALE IN THE ANADARKO BASIN**




*Source: ALL Consulting, 2009*

## *The Antrim Shale*

The Antrim Shale is located in the upper portion of the lower peninsula of Michigan within the Michigan Basin (Exhibit 23[154]). This Late Devonian-age shale is bounded by shale (Bedford Shale) above and by limestone (Squaw Bay Limestone) below and occurs at depths of 600 ft to 2,200 ft which is more typical of CBNG formations than most gas shales (Exhibit 22 and Exhibit 11).

Aside from the Barnett, the Antrim Shale has been one of the most actively developed shale gas plays with its major expansion taking place in the late 1980s[155].

The Antrim Shale encompasses an area of approximately 12,000 square miles and is characterized by distinct differences from other gas shales: shallow depth, small stratigraphic thickness with average net pay of 70 ft to 120 ft, and greater volumes of produced water in the range of 5 to 500 bbls/day/well[156] (Exhibit 11).

The gas content of the Antrim Shale ranges between 40 scf/ton and 100 scf/ton (Exhibit 11). The original gas-in-place for the Antrim is estimated at 76 tcf with technically recoverable resources estimated at 20 tcf (Exhibit 11). Well spacing ranges from 40 acres to 160 acres per well.

**EXHIBIT 22: STRATIGRAPHY OF THE ANTRIM SHALE**

<table>
<tr><th colspan="2">Period</th><th colspan="3">Formation</th></tr>
<tr><td>Quaternary</td><td>Pleistocene</td><td colspan="3">Glacial Drift</td></tr>
<tr><td>Jurassic</td><td>Middle</td><td colspan="3">Ionia Formation</td></tr>
<tr><td rowspan="3">Pennsylvanian</td><td>Late</td><td colspan="3">Grand River Formation</td></tr>
<tr><td rowspan="2">Early</td><td colspan="3">Saginaw Formation</td></tr>
<tr><td colspan="3" rowspan="2">Parma Formation</td></tr>
<tr><td rowspan="6">Mississippian</td><td rowspan="3">Late</td></tr>
<tr><td colspan="3">Bayport Limestone</td></tr>
<tr><td colspan="3">Michigan Formation</td></tr>
<tr><td rowspan="3">Early</td><td colspan="3">Marshall Sandstone</td></tr>
<tr><td colspan="3">Coldwater Shale</td></tr>
<tr><td colspan="3">Sunbury Shale</td></tr>
<tr><td rowspan="7">Devonian</td><td rowspan="7">Late</td><td rowspan="2">Ellsworth Shale</td><td colspan="2">Berea Sandstone</td></tr>
<tr><td colspan="2">Bedford Shale</td></tr>
<tr><td colspan="2">Upper Member</td><td rowspan="4">Antrim Shale</td></tr>
<tr><td colspan="2">Lachine Member</td></tr>
<tr><td colspan="2">Paxton Member</td></tr>
<tr><td colspan="2">Norwood Member</td></tr>
<tr><td colspan="3">Squaw Bay Limestone</td></tr>
</table>

*Source: Catacosinos et al, 2000[157]*

**EXHIBIT 23: ANTRIM SHALE IN THE MICHIGAN BASIN**


*Source: ALL Consulting, 2009*

**EXHIBIT 24: STRATIGRAPHY OF THE NEW ALBANY SHALE**

| Period | | Formation | |
|---|---|---|---|
| Pennsylvanian | Missourian | Mattoon | |
| | | Bond | |
| | | Patoka | |
| | Desmoinesian | Shelburn | |
| | | Dugger | |
| | | Petersburg | |
| | | Linton | |
| | | Staunton | |
| | Atokan | Brazil | |
| | Morrowan | Mansfield | |
| Mississippian | Chesterian | Tobinsport | |
| | | Branchville | |
| | | Tar Springs | |
| | | Glen Dean Limestone | |
| | | Hardinsburg | |
| | | Haney Limestone | |
| | | Big Clifty | |
| | | Beech Creek Limestone | |
| | | Cypress | Elwren |
| | | Reelsville Limestone | |
| | | Sample | |
| | | Beaver Bend Limestone | |
| | | Bethel | |
| | | Paoli Limestone | |
| | | Ste. Genevieve Ls. | |
| | Valmeyeran | St. Louis Limestone | |
| | | Salem Limestone | |
| | | Harrodsburg Limestone | |
| | | Muldraugh | Ramp Creek |
| | | Edwardsville | |
| | | Spickert Knob | |
| | | New Providence Sh. | |
| | Kinderhookian | Rockford Ls | Coldwater Sh. |
| | | New Albany Shale | Sunbury Sh. |
| | | | Ellsworth Sh. |
| Devonian | Senecan Chautauquan | | |
| | | | Antrim Sh. |
| | Erian | | |
| | | North Vernon Ls. | Transverse |
| | | Jeffersonville Ls. | Detroit River |

Source: *Indiana Geological Survey, 1986*[158]

### *The New Albany Shale*

The New Albany Shale is located in the Illinois Basin in portions of southeastern Illinois, southwestern Indiana, and northwestern Kentucky[159] (Exhibit 25[160]). Similar to the Antrim Shale, the New Albany occurs at depths between 500 ft and 2,000 ft (Exhibit 11) and is a shallower, water-filled shale with a more CBNG-like character than the other gas shales discussed in this section. The New Albany formation is a Devonian- to Mississippian-age shale bounded by limestone above (Rockford Limestone) and below (North Vernon Limestone) (Exhibit 24).

The New Albany Shale is one of the largest shale gas plays, encompassing an area of approximately 43,500 square miles with approximately 80-acre spacing between wells (Exhibit 11). Similar to the Antrim Shale, the New Albany play has a thinner average net pay thickness of 50 ft to 100 ft and has wells which average 5 to 500 bbls of water per day[161] (Exhibit 11). The measured gas content of the New Albany Shale ranges from 40 scf/ton to 80 scf/ton. The original gas-in-place for the New Albany formation is estimated at 160 tcf with technically recoverable resources estimated at less than 20 tcf (Exhibit 11).

**EXHIBIT 25: NEW ALBANY SHALE IN THE ILLINOIS BASIN**


*Source: ALL Consulting, 2009*

# REGULATORY FRAMEWORK

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency (EPA) administers most of the federal laws, although development on federally owned land is managed primarily by the Bureau of Land Management (BLM), which is part of the Department of the Interior, and the U.S. Forest Service, which is part of the Department of Agriculture. In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies. Those laws and their delegation are discussed below.

## Federal Environmental Laws Governing Shale Gas Development

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act (CWA) regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act (SDWA) regulates the underground injection of fluids from shale gas activities. The Clean Air Act (CAA) limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts.

However, federal agencies do not have the resources to administer all of these environmental programs for all the oil and gas sites around the country. Also, as explained below, one set of nation-wide regulations may not always be the most effective way of assuring the desired level of environmental protection. Therefore, most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight). By statute, states may adopt their own standards; however, these must be at least as protective as the federal standards they replace, and may even be more protective in order to address local conditions. Once these state programs are approved by the relevant federal agency (usually the EPA), the state then has primacy jurisdiction.

***By statute, states may adopt their own standards; however, these must be at least as protective as the federal standards they replace, and may even be more protective in order to address local conditions.***

## State Regulation

State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-size-fits-all regulation at the federal level[162]. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. The state agencies that permit these practices and monitor and enforce their laws and regulations may be located in the state Department of Natural Resources (such as in Ohio) or in the Department of Environmental Protection (such as in Pennsylvania). The Texas Railroad Commission regulates oil and gas activity in the nation's largest oil and gas producing state, home to the Barnett Shale. The names and organizational structures vary, but the functions are very similar. Often, multiple agencies are involved, having jurisdiction over different activities and aspects of development.

These state agencies do not only implement and enforce federal laws; they also have their own sets of state laws to administer. These state laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

***The states have broad powers to regulate, permit, and enforce all activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well.***

States have many tools at their disposal to assure that shale gas operations do not adversely impact the environment. The regulation of shale gas drilling and production is a cradle-to-grave approach. The states have broad powers to regulate, permit, and enforce all activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. Different states take different approaches to this regulation and enforcement, but state laws generally give the state oil and gas director or agency the discretion to require whatever is necessary to protect human health and the environment[a]. In addition to the general protection regulations, most states have a general prohibition against pollution from oil and gas drilling and production[b]. Most of the state requirements are written into rules or regulations, while some are added to permits on a case-by-case basis as a result of environmental review, on-the-ground inspections, public comments, or commission hearings.

All states require a permit before an operator can drill and operate a gas well. The application for this permit includes all the information about a well's location, construction, operation and reclamation. Agency staff reviews the application for compliance with regulations and to assure adequate environmental safeguards. If necessary, a site inspection will be made before permit approval. Also, most states require operators to post a bond or other financial security when getting a drilling permit to ensure compliance with state regulations and to make sure that there are funds to properly plug the well once production ceases. Another safeguard is that producers

[a] An example of this type of provision is the following from Pennsylvania's statute: "[T]he department shall have the authority to issue such orders as are necessary to aid in the enforcement of the provisions of [the oil and gas] act." (58 P.S. section 601.503.).

[b] An example of such language can be found in New York's rules, which state: "The drilling, casing and completion program adopted for any well shall be such as to prevent pollution. Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited." (6 NYCRR Part 554). Another example is the requirement in the rules of the Texas Railroad Commission: "No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state." (TAC 16.1.3.8).

generally must notify the state agencies of any significant new activity through a "sundry notice" or a new permit application so that the agency is aware of that activity and can review it[c].

States have implemented voluntary review processes to help ensure that the state programs are as effective as possible. The Ground Water Protection Council (GWPC) has a program to review state implementation of the Underground Injection Control (UIC) program. In addition to the GWPC UIC review, state oil and gas environmental programs other than UIC programs can also be periodically reviewed against a set of guidelines developed by an independent body of state, industry, and environmental stakeholders, known as STRONGER (State Review of Oil and Natural Gas Environmental Regulation, Inc.)[163]. Periodic evaluations of state exploration and production waste management programs have proven useful in improving the effectiveness of those programs and increasing cooperation between federal and state regulatory agencies. To date, 18 states have been reviewed under the state review guidelines, and several have been reviewed more than once. The STRONGER program has documented the effectiveness of and improvements in these state oil and gas environmental programs[164,165]. The Interstate Oil and Gas Compact Commission (IOGCC) also completed state reviews using earlier versions of the guidelines prior to the formation of STRONGER.

The organization of regulatory agencies within the various oil and gas producing states varies considerably. Some states have several agencies that may oversee some facet of oil and gas operations, especially environmental requirements. These agencies may be in various departments or divisions within the states' organizations. These various approaches have developed over time within each state, and each state tries to create a structure that best serves its citizenry and all of the industries that it must oversee. The one constant is that each oil and gas producing state has one agency with primary responsibility for permitting wells and overseeing general operations. While this agency may work with other agencies in the regulatory process, they can serve as a good source of information about the various agencies that may have jurisdiction over oil and gas activities. Exhibit 26 provides a list of the agencies with primary responsibility for oil and gas regulation in each of the states that have or are likely to have shale gas production.

## Local Regulation

In addition to state and federal requirements, additional requirements regarding oil and gas operations may be imposed by other levels of government in specific locations. Entities such as cities, counties, tribes, and regional water authorities may each set operational requirements that affect the location and operation of wells or require permits and approvals in addition to those at the federal or state level.

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[c] See, for example, Louisiana Statewide Order 29-B, section 105, or Texas Administrative Code 16.1.3.5.

**EXHIBIT 26: OIL AND GAS REGULATORY AGENCIES IN SHALE GAS STATES**

| State | Agency | Web Address |
|---|---|---|
| Alabama | Geological Survey of Alabama, State Oil and Gas Board | http://www.ogb.state.al.us/ogb/ogb.html |
| Arkansas | Arkansas Oil and Gas Commission | http://www.aogc.state.ar.us/ |
| Colorado | Colorado Department of Natural Resources, Oil and Gas Conservation Commission | http://cogcc.state.co.us/ |
| Illinois | Illinois Department of Natural Resources, Division of Oil and Gas | http://dnr.state.il.us/mines/dog/index.htm |
| Indiana | Indiana Department of Natural Resources, Division of Oil and Gas | http://www.in.gov/dnr/dnroil/ |
| Kentucky | Kentucky Department for Energy Development and Independence, Division of Oil and Gas Conservation | http://www.dogc.ky.gov/ |
| Louisiana | Louisiana Department of Natural Resources, Office of Conservation | http://dnr.louisiana.gov/cons/conserv.ssi |
| Michigan | Michigan Department of Environmental Quality, Office of Geological Survey | http://www.michigan.gov/deq/0,1607,7-135-3306_28607---,00.html |
| Mississippi | Mississippi State Oil and Gas Board | http://www.ogb.state.ms.us/ |
| Montana | Montana Department of Natural Resources and Conservation, Board of Oil and Gas | http://bogc.dnrc.mt.gov/default.asp |
| New Mexico | New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division | http://www.emnrd.state.nm.us/OCD/ |
| New York | New York Department of Environmental Conservation, Division of Mineral Resources | http://www.dec.ny.gov/energy/205.html |
| North Dakota | North Dakota Industrial Commission, Department of Mineral Resources Oil and Gas Division | https://www.dmr.nd.gov/oilgas/ |
| Ohio | Ohio Department of Natural Resources, Division of Mineral Resources Management | http://www.ohiodnr.com/mineral/default/tabid/10352/Default.aspx |
| Oklahoma | Oklahoma Corporation Commission, Oil and Gas Conservation Division | http://www.occ.state.ok.us/Divisions/OG/newweb/og.htm |
| Pennsylvania | Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management | http://www.dep.state.pa.us/dep/DEPUTATE/MINRES/OILGAS/oilgas.htm |
| Tennessee | Tennessee Department of Environment and Conservation, State Oil and Gas Board | http://www.tennessee.gov/environment/boards/oilandgas.shtml |
| Texas | The Railroad Commission of Texas | http://www.rrc.state.tx.us/index.html |
| West Virginia | West Virginia Department of Environmental Protection, Office of Oil and Gas | http://www.wvdep.org/item.cfm?ssid=23 |

When operations occur in or near populated areas, local governments may establish ordinances to protect the environment and the general welfare of its citizens. These local ordinances frequently require additional permits for issues such as well placement in flood zones, noise level, set backs from residences or other protected sites, site house-keeping, and traffic. For example, ordinances may set limits on noise levels that may be generated during both daytime and nighttime operations[166,167,168,169].

In some cases, regional water-permitting authorities that have jurisdiction in multiple states have also been established. These federally established authorities have been created to protect the water quality of the entire river basin and to govern uses of the water[170]. Additional approvals and permits may be required for operations in these river basins. For example, the Delaware River Basin Commission (DRBC) covers parts of New York, Pennsylvania, New Jersey and Delaware[171]. Natural gas operators wishing to withdraw water for consumptive use in this basin must first receive a permit from the DRBC, which has the legal authority to fine violators of their rules and regulations.

The variety of laws governing shale gas exploration and production, and the multitude of federal and state agencies that implement them, can sometimes be confusing. Therefore, the following discussion has been organized according to the various environmental media that are affected by these activities, i.e., water, air, and land. The major laws and programs affecting each of these are discussed below. Additional considerations on federal land and unique state requirements are also covered, along with some of the programs that cut across these environmental media.

## Regulation of Impacts on Water Quality

Potential impacts to water quality are primarily regulated under several federal statutes and the accompanying state programs. The primary federal statutes governing water quality issues related to shale gas development are the Clean Water Act, the Safe Drinking Water Act, and the Oil Pollution Act. These statutes and their relationships to shale gas development are discussed below.

### *Clean Water Act*

The Clean Water Act (CWA) is the primary federal law in the U.S. governing pollution of surface water. It was established to protect water quality, and includes regulation of pollutant limits on the discharge of oil- and gas-related produced water. This is conducted through the National Pollutant Discharge Elimination System (NPDES) permitting process. Although EPA sets national standards at the federal level, states and tribal governments can acquire primacy for the NPDES program by meeting EPA's primacy requirements.

The CWA establishes the basic structure for regulating discharges of pollutants into the waters of the U.S. and quality standards for surface waters. The basis of the CWA was enacted in 1948 and was called the Federal Water Pollution Control Act; the Act was significantly reorganized and expanded in 1972. "Clean Water Act" became its common name, with additional amendments made in 1977 and later.

Under the CWA, EPA has implemented pollution control programs such as setting wastewater standards for industry. They have also set water quality standards for a variety of contaminants in surface waters.

The CWA made it unlawful to discharge any pollutant from a point source into the navigable waters of the U.S., unless done in accordance with a specific approved permit. The NPDES permit program controls discharges from point sources that are discrete conveyances, such as pipes or man-made ditches. Industrial, municipal, and other facilities such as shale gas production sites or commercial facilities that handle the disposal or treatment of shale gas produced water must obtain permits if they intend to discharge directly into surface waters[172,173]. Large facilities usually have individual NPDES permits. Discharges from some smaller facilities may be eligible for inclusion under general permits that authorize a category of discharges under the CWA within a geographical area. A general permit is not specifically tailored for an individual discharger. Most oil and gas production facilities with related discharges are authorized under general permits because there are typically numerous sites with common discharges in a geographic area.

A state that meets the federal primacy requirements is allowed to set more stringent state-specific standards for this program. Since individual states can acquire primacy over their respective programs, it is not uncommon to have varying requirements from state to state. This variation can affect how the oil and gas industry manages produced water within a drainage basin located within two or more states, such as the Marcellus shale in the Appalachian Basin. Effluent limitations serve as the primary mechanism under NPDES permits for controlling discharges of pollutants to receiving waters. When developing effluent limitations for an NPDES permit, a permit writer must consider limits based on both the technology available to control the pollutants (i.e., technology-based effluent standards) and the regulations that protect the water quality standards of the receiving water (i.e., water quality-based effluent standards).

The intent of technology-based effluent limits in NPDES permits is to require treatment of effluent concentrations to less than a maximum allowable standard for point source discharges to the specific surface water body. This is based on available treatment technologies, while allowing the discharger to use any available control technique to meet the limits. For industrial (and other non-municipal) facilities, technology-based effluent limits are derived by: 1) using national effluent limitations guidelines and standards established by EPA, or 2) using best professional judgment (BPJ) on a case-by-case basis in the absence of national guidelines and standards.

Prior to the granting of a permit, the authorizing agency must consider the potential impact of every proposed surface water discharge on the quality of the receiving water, not just individual discharges. If the authorizing agency determines that technology-based effluent limits are not sufficient to ensure that water quality standards will be attained in the receiving water, the CWA [Section 303(b)(1)(c)] and NPDES regulations [40 Code of Federal Regulations (CFR) 122.44(d)] require that more stringent limits are imposed as part of the permit[174].

EPA establishes effluent limitation guidelines (ELGs) and standards for different non-municipal (i.e., industrial) categories. These guidelines are developed based on the degree of pollutant reduction attainable by an industrial category through the application of pollution control technologies.

The CWA requires EPA to develop specific effluent guidelines that represent the following:

1. Best conventional technology (BCT) for control of conventional pollutants and applicable to existing dischargers.
2. Best practicable technology (BPT) currently available for control of conventional, toxic and nonconventional pollutants and applicable to existing dischargers.
3. Best available technology (BAT) economically achievable for control of toxic and nonconventional pollutants and applicable to existing dischargers.
4. New source performance standards (NSPS) for conventional pollutants and applicable to new sources.

To date, EPA has established guidelines and standards for more than 50 different industrial categories[175].

The ELGs for Oil and Gas Extraction, which were published in 1979, can be found at 40 CFR Part 435. The onshore subcategory, Subpart C, is applicable to discharges associated with shale gas development and production[176].

The CWA also includes a program to control storm water discharges. The 1987 Water Quality Act (WQA) added Section 402(p) to the CWA requiring EPA to develop and implement a storm water permitting program. EPA developed this program in two phases (Phase I: 1990; Phase II: 1999). Those regulations establish NPDES permit requirements for municipal, industrial, and construction site storm water runoff. The WQA also added Section 402(l)(2) to the CWA specifying that the EPA and states shall not require NPDES permits for uncontaminated storm water discharges from oil and gas exploration, production, processing or treatment operations, or transmission facilities. This exemption applies where the runoff is not contaminated by contact with raw materials or wastes. EPA had previously interpreted the 402(l)(2) exemption as not applying to construction activities of oil and gas development, such as building roads and pads (i.e., an NPDES permit was required)[177].

The Energy Policy Act of 2005 modified the CWA Section 402(l)(2) exemption by defining the excluded oil and gas sector operations to include all oil and gas field activities and operations, including those necessary to prepare a site for drilling and for the movement and placement of drilling equipment. EPA promulgated a rule that implemented this exemption. However, on May 23, 2008, the U.S. Court of Appeals for the Ninth Circuit released a decision vacating the permitting exemption for discharges of sediment from oil and gas construction activities that contribute to violations of the CWA[178]. The court based its decision on the fact that the new rule exempted runoff contaminated with sediment, while the CWA does not exempt such runoff. As a result of the court's decision, storm water discharges contaminated with sediment resulting in a water quality violation require permit coverage under the NPDES storm water permitting program.

While the EPA storm water permitting rule contains a broad exclusion for oil and gas sector construction activities, it is important to note that individual states and Indian tribes may still regulate storm water associated with these activities. EPA has clarified its position that states and tribes may not regulate such storm water discharges under their CWA authority, but are free to regulate under their own independent authorities. EPA states that "[t]his final rule is not intended to interfere with the ability of states, tribes, or local governments to regulate any discharges through a non-NPDES permit program"[179]. In addition to state and tribal regulation, the industry has a voluntary program of Reasonable and Prudent Practices for Stabilization (RAPPS) of oil and gas construction sites[180]. Producers use RAPPS in order to control erosion and sedimentation associated with storm water runoff from areas disturbed by clearing, grading, and excavating activities related to site preparation.

### *Safe Drinking Water Act*

Congress originally passed the Safe Drinking Water Act (SDWA) in 1974 to protect public health by regulating the nation's public drinking water supply. The law was amended in 1986 and 1996 and requires many actions to protect drinking water and its sources, including rivers, lakes, reservoirs, springs, and ground water wells. SDWA authorizes the U.S. EPA to set national health-based standards for drinking water to protect against both naturally occurring and man-made contaminants that may be found in drinking water. EPA, states, and municipal water system agencies then work together to make sure that these standards are met[181].

As one aspect of the protection of drinking water supplies, the SDWA establishes a framework for the Underground Injection Control (UIC) program to prevent the injection of liquid wastes into underground sources of drinking water (USDWs). The EPA and states implement the UIC program, which sets standards for safe waste injection practices and bans certain types of injection altogether. The UIC Program provides these safeguards so that injection wells do not endanger USDWs. The first federal UIC regulations were issued in 1980.

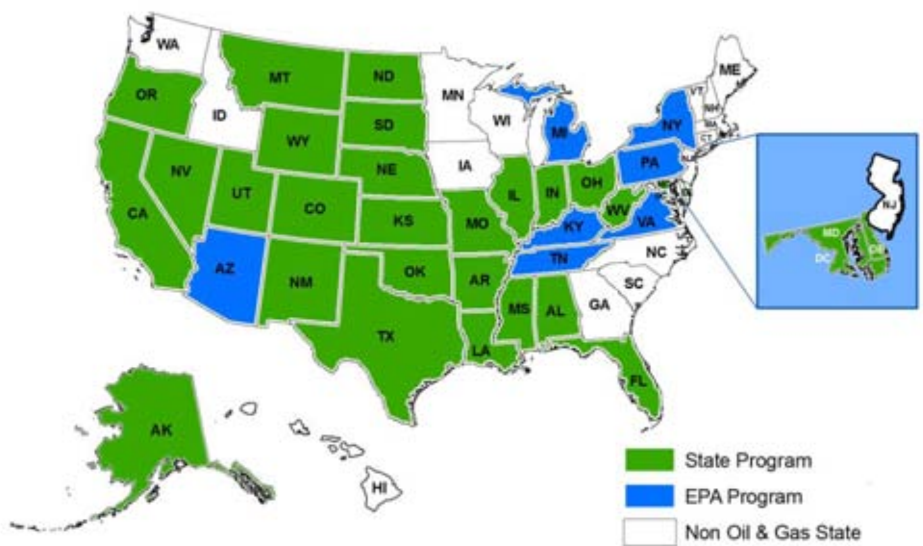
EPA currently groups underground injection wells into five classes for regulatory control purposes, and has a sixth class under consideration. Each class includes wells with similar functions, construction and operating features so that technical requirements can be applied consistently to the class.

1. **Class I** wells may inject hazardous and nonhazardous fluids (industrial and municipal wastes) into isolated formations beneath the lowermost USDW. Because they may inject hazardous waste, Class I wells are the most strictly regulated and are further regulated under the Resource Conservation and Recovery Act (RCRA).
2. **Class II** wells may inject brines and other fluids associated with oil and gas production.
3. **Class III** wells may inject fluids associated with solution mining of minerals.
4. **Class IV** wells may inject hazardous or radioactive wastes into or above a USDW and are banned unless specifically authorized under other statutes for ground water remediation.
5. **Class V** includes all underground injection not included in Classes I-IV. Generally, most Class V wells inject nonhazardous fluids into or above a USDW and are on-site disposal systems, such as floor and sink drains which discharge to dry wells, septic systems, leach fields, and drainage wells. Injection practices or wells that are not covered by the UIC Program include single family septic systems and cesspools as well as non-residential septic systems and cesspools serving fewer than 20 persons that inject ONLY sanitary waste water.
6. **Class VI** has been proposed specifically for the injection of $CO_2$ for the purpose of sequestration, but has not yet been established.

Most injection wells associated with oil and gas production are Class II wells. These wells may be used to inject water and other fluids (e.g., liquid $CO_2$) into oil- and gas-bearing zones to enhance recovery, or they may be used to dispose of produced water. The regulation specifically prevents the disposal of waste fluids into USDWs by limiting injection only to formations that are not "underground sources of drinking water." EPA's UIC Program is designed to prevent contamination of water supplies by setting minimum requirements for state UIC Programs. The basic premise of the UIC Program is to prevent contamination of USDWs by keeping injected fluids within the intended injection zone. The injected fluids must not endanger, or have the potential to endanger, a current or future public water supply. The UIC requirements that affect the siting, construction, operation, maintenance, monitoring, testing, and, finally, closure of injection wells have been established to address these concepts. All injection wells require authorization under general rules or specific permits.

The law was written with the understanding that states are best suited to have primary enforcement authority (primacy) for the UIC Program. In the SDWA, Congress cautioned EPA against a "one-size-fits-all" regulatory scheme, and mandated consideration of local conditions and practices. Section 1421(b)(3)(A) requires that UIC regulations permit or provide consideration of varying geological, hydrological, or historical conditions in different states and in different areas within a state. Section 1425 allows a state to obtain primacy from EPA for oil- and gas-related injection wells, without being required to adopt the complete set of applicable federal UIC regulations. The state must be able to demonstrate that its existing regulatory program is protecting USDWs as effectively as the federal requirements[182].

**EXHIBIT 27: UIC CLASS II PRIMACY MAP**




*Source: EPA,, 2008*

To date, 40 states have obtained primacy for oil and gas injection wells (Class II), although, as shown in Exhibit 27 not all of these states have oil and gas production. The U.S. EPA administers UIC programs for ten states, seven of which are oil and gas states, and all other federal jurisdictions and Indian Lands[183] (Exhibit 27[184]).

### *Oil Pollution Act of 1990 – Spill Prevention Control and Countermeasure*

The CWA and the Oil Pollution Act (OPA) include both regulatory and liability provisions that are designed to reduce damage to natural resources from oil spills. Congress added Section 311 to the

CWA, which in part authorized the President to issue regulations establishing procedures, methods, equipment, and other requirements to prevent discharges of oil from vessels and facilities [Section 311(j)(1)(c)]. In response to the Exxon Valdez oil spill in Alaska, Congress enacted the OPA in 1990[185]. The OPA amended CWA Section 311 and contains provisions applicable to onshore facilities and operations.

Section 311, as amended by the OPA, provides for spill prevention requirements, spill reporting obligations, and spill response planning. It regulates the prevention of and response to accidental releases of oil and hazardous substances into navigable waters, on adjoining shorelines, or affecting natural resources belonging to or managed by the U.S. This authority is primarily carried out through the creation and implementation of facility and response plans. These plans are intended to establish measures that will prevent discharge of oil into navigable waters of the U.S. or adjoining shore-lines as opposed to response and cleanup after a spill occurs.

A cornerstone of the strategy to prevent oil spills from reaching the nation's waters is the oil Spill Prevention, Control and Countermeasure (SPCC) plan. EPA promulgated regulations to implement this part of the OPA of 1990. These regulations specify that:

1. SPCC Plans must be prepared, certified (by a professional engineer) and implemented by facilities that store, process, transfer, distribute, use, drill for, produce, or refine oil;
2. Facilities must establish procedures and methods and install proper equipment to prevent an oil release;
3. Facilities must train personnel to properly respond to an oil spill by conducting drills and training sessions; and,
4. Facilities must also have a plan that outlines steps to contain, clean up and mitigate any effects that an oil spill may have on waterways[186].

Before a facility is subject to the SPCC rule, it must meet three criteria:

1. It must be non-transportation-related;
2. It must have an aggregate aboveground storage capacity greater than 1,320 gallons (31.4 bbls) or a completely buried storage capacity greater than 42,000 gallons (1,000 bbls); and
3. There must be a reasonable expectation of a discharge into or upon navigable waters of the U.S. or adjoining shorelines.

An SPCC Plan is a site-specific document that describes the measures the facility owner has taken to prevent oil spills, and what measures are in place, if needed, to contain and clean spills. It includes information about the facility, the oil storage containment, inspections, and a site diagram with locations of tanks (above and below ground) and drainage, and other pertinent details. Prevention measures include secondary containment around tanks and certain oil-containing equipment.

The SPCC program is not as applicable to shale gas operations as it is to oil production sites. Shale gas operators may have to prepare plans if they store large amounts of fuel (exceeding the volumes stated above) on site, or if oil-filled equipment is present, and there is a risk of that oil impacting waters of the U.S.

In October 2007, EPA proposed amendments to the SPCC rule intended to increase clarity and tailor certain requirements to ensure increased compliance. Among other things, these amendments would streamline some requirements by allowing the use of a plan template for smaller facilities, extending some deadlines for plan preparation, and exempting some vessels and flow lines from secondary containment requirements. They would also add spill prevention requirements for some oil and gas facilities. These proposed rules have not yet been made final[187].

### *State Regulations and Regional Cooperation*

In addition to implementing federal statutes for the NPDES, UIC, and storm water programs, states and tribes may impose their own requirements to protect their water resources, both surface and underground. For example, they establish water quality standards for some or all of their surface water. These standards are approved by EPA and become the baseline for CWA permits[188].

In addition, some areas have established regional water authorities that regulate water withdrawals and discharges within a river basin. For example, the Susquehanna River Basin Commission (SRBC)[189] and the DRBC[190] in New York and Pennsylvania require that entities seeking to withdraw water from their river systems first obtain permits. These commissions have authority separate from the states. They have recently directed their attention to the water requirements for drilling and hydraulically fracturing Marcellus Shale gas wells and are updating their requirements for both water withdrawals and discharge of the water after use. Other river basin commissions are more advisory in nature, providing water flow and quality information and coordinating river conservation efforts by state agencies and others.

State agencies are the principal organizations for enforcing water quality regulations. They have inspectors, usually located at regional offices throughout the state, who visit oil and gas well sites to ensure compliance with regulations. When a violation occurs, state enforcement and legal personnel develop the case and order compliance, in many cases also imposing penalties against the violator. Penalties can range from fines to revocation of permits, and even to criminal sanctions in severe cases. Such penalties are usually imposed only after hearings before a board of commissioners or other state body. In addition to fines and penalties, companies that pollute surface or ground water must clean up or remediate the contamination they caused.

## Regulation of Impacts on Air Quality

Air quality impacts are regulated under the Clean Air Act (CAA). As described below, the Act sets national standards for emissions of certain pollutants and requires permits for some industrial operations. Greenhouse Gases are not regulated as such, and are not, therefore, discussed in this section.

### *Clean Air Act*

The CAA is the primary means by which EPA regulates potential emissions that could affect air quality. The U.S. Congress passed the CAA in 1963, and they have amended it on several occasions since, most recently in 1990[191]. The CAA requires EPA to set national standards to limit levels of certain pollutants. EPA regulates those pollutants by developing human health-based and/or environmentally and scientifically based criteria for setting permissible levels. Air regulations do not normally include exceptions for a company's size, the age of a field, or the type of operation. Typically, the air rules are silent on issues such as conventional versus unconventional plays, old versus new fields, and the depth of a well. For the most part, the air emissions, applicable regulations, and associated emissions controls for a shale play are no different than those for any other natural gas operation. There may be differences due to location (some areas of the country have better air quality than others), equipment needs (some shale plays may produce a wetter gas than others), and sulfur content level of the gas.

Geographic areas that do not meet EPA's standards for a given pollutant are designated as "nonattainment areas"[192]. This is the case for the Barnett Shale play, much of which is located in or near the Dallas-Fort Worth ozone nonattainment area. As a result, Barnett Shale production activities must often comply with much more stringent regulations than similar operations proposed outside of a nonattainment area. As a result of the implementation of the CAA, air quality has improved dramatically across the U.S. during the last few decades and existing regulations should continue to reduce air pollution emissions during the next twenty years or longer[193].

### *Air Quality Regulations*

Like any other U.S. industry, shale gas producers must comply with existing and new air regulations including those resulting from the 1990 CAA Amendments. These rules pose an ongoing challenge to company resources as producers strive to understand and comply with enforcement, fines, public reaction, and possibly even project cancellations in light of new standards.

EPA has established National Emission Standards for Hazardous Air Pollutants (NESHAPs), which are nationally uniform standards to control specific air emissions. In 2007, EPA implemented a new standard referred to as the Maximum Achievable Control Technology (MACT) standard for hazardous air pollutants (HAP) that targeted small area sources such as shale gas operations located in areas near larger populations. These standards limit HAP emissions (primarily benzene) from process vents on glycol dehydration units, storage vessels with flash emissions, and equipment leaks.

Another example of new or amended federal regulations that will have a direct impact on controlling emissions from shale gas operations is the Stationary Spark Ignition Internal Combustion Engine new source performance standard[194] and Reciprocating Internal Combustion Engine NESHAP[195] rules, which regulate new and refurbished engines. These rules, passed in 2007, target all internal combustion engines regardless of horsepower rating, location, or fuel (electric engines are not included) and include extensive maintenance, testing, monitoring, recordkeeping, and reporting requirements[196].

EPA is not large enough to regulate every air emissions source nationwide, let alone consider the local and regional differences. Therefore, they typically delegate that role to local, state, and tribal agencies. This delegation of authority can include rule implementation, permitting, reporting, and compliance. Any state given such delegation of authority can pass more restrictive rules, but they are prohibited from passing a rule that is less stringent than its federal counterpart.

### *Air Permits*

Air permits are legal documents that facility owners and operators must abide by. The permit specifies what construction is allowed, what emission limits must be met, how the emissions source(s) must be operated, and what conditions—specifying monitoring, record keeping, and reporting requirements—must be maintained to assure ongoing compliance. Shale gas producers may need air quality permits for a number of emissions sources, including gas compressor engines, glycol dehydrators, and flares.

A company's permitting responsibility does not end with the issuance of their initial air permit. They must be constantly vigilant that a new regulation, modification, replacement, or process change does not impact their existing permit and require a permit amendment or a more stringent permit. Although these permits may differ across the country, they all contain specific conditions designed to ensure state and federal standards are met and to prevent any significant degradation in air quality as a result of a proposed activity.

## Regulation of Impacts to Land

Impacts to land from shale gas operations include solid waste disposal and surface disturbances that may impact the visual landscape or may affect wildlife habitat. Operations on federal lands are a special case with unique requirements that are discussed below.

### *Resource Conservation and Recovery Act (RCRA)*

RCRA was passed in 1976 to address the growing problems of the increasing volume of municipal and industrial waste. RCRA established goals for protecting human health and the environment, conserving resources, and reducing the amount of waste. RCRA Subtitle C established a federal program to manage hazardous wastes from cradle to grave to ensure that hazardous waste is handled in a manner that protects human health and the environment. Subtitle D of the RCRA addresses non-hazardous solid wastes, including certain hazardous wastes which are exempted from the Subtitle C regulations[197].

In 1978, EPA proposed hazardous waste management standards that included reduced requirements for some industries, including oil and gas, with large volumes of wastes. EPA determined that these large volume "special wastes" were lower in toxicity than other wastes being regulated as hazardous waste under the RCRA[198].

In 1980, the Solid Waste Disposal Act (SWDA) amended RCRA to exempt drilling fluids, produced waters, and other wastes associated with exploration, development, and production of crude oil, natural gas and geothermal energy[199]. The SWDA Amendments also required EPA to provide a report to Congress on these wastes and to make a regulatory determination as to whether regulation of these wastes under RCRA Subtitle C was warranted[200].

***In 1988, EPA issued a final regulatory determination stating that control of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted.***

In 1987, EPA issued a Report to Congress that outlined the results of a study on the management, volume, and toxicity of wastes generated by the oil, natural gas and geothermal industries. In 1988, EPA issued a final regulatory determination stating that control of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted. EPA made this determination because it found that other state and federal programs could protect human health and the environment more effectively. In lieu of regulation under Subtitle C, EPA implemented a three-pronged strategy to ensure that the environmental and programmatic issues were addressed:

1. Improve other federal programs under existing authorities;
2. Work with states to improve some programs; and
3. Work with Congress to develop any additional statutory authorities that may be required[201].

These wastes have remained exempt from Subtitle C regulations, but this does not preclude these wastes from control under state regulations or other federal regulations[202]. The exemption applies only to the federal requirements of RCRA Subtitle C. A waste that is exempt from Subtitle C regulation might be subject to more stringent or broader state hazardous and non-hazardous waste regulations and other state and federal program regulations. For example, oil and gas exploration and production wastes may be subject to regulation under RCRA Subtitle D, the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act, and/or the Oil Pollution Act of 1990[203,204].

In 1989, EPA worked with the Interstate Oil and Gas Compact Commission (IOGCC), state regulatory officials, industry representatives, and nationally recognized environmental groups to establish a Council on Regulatory Needs. The purpose of the council was to review existing state oil and gas exploration and production waste management programs and to develop guidelines to describe the elements necessary for an effective state program. This effort was begun by EPA as part of the second prong of the agency's approach. These groups then worked together with state regulatory agencies to review the state programs, on a voluntary basis, against these guidelines and to make recommendations for improvement. This state review program continues today under the guidance of a non-profit organization called STRONGER. The state programs reviewed to date represent over 90% of the onshore domestic production[205].

Working with the IOGCC, STRONGER has continued to update the guidelines consistent with developing environmental and oilfield technologies and practices. Under the state review process, state programs have continued to improve, and follow-up reviews have shown significant improvement where states have successfully implemented the recommendations of the review committees.

### *Endangered Species Act*

The Endangered Species Act (ESA) of 1973 (Pub. L. 93-205) protects plants and animals that are listed by the federal government as "endangered" or "threatened"[206]. Sections 7 and 9 are central to regulating oil and gas activities. Section 9 makes it unlawful for anyone to "take" a listed animal, and this includes significantly modifying its habitat[207]. This applies to private parties and private land; a landowner is not allowed to harm an endangered animal or its habitat on his or her property.

Section 7 applies not to private parties, but to federal agencies. This section covers not only federal activities but also the issuance of federal permits for private activities, such as Section 404 permits issued by the Corps of Engineers, to people who want to do construction work in waters or wetlands[208]. Section 7 imposes an affirmative duty on federal agencies to ensure that their actions (including permitting) are not likely to jeopardize the continued existence of a listed species (plant or animal) or result in the destruction or modification of critical habitat. Both Sections 7 and 9 allow "incidental takes" of threatened or endangered species, but only with a permit.

To "take" is to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect a plant or animal of any threatened or endangered species. Harm includes significant habitat modification when it kills or injures a member of a listed species through impairment of essential behavior (e.g., nesting or reproduction).

For any non-federal industrial activity, the burden is on the owner and/or operator to determine if an incidental take permit is needed. This is typically accomplished by contacting the U.S. Fish and Wildlife Service (FWS) to determine whether any listed species are present or will potentially inhabit the project site. A biological survey may be required to determine whether protected species are present on the site and whether a Section 9 permit may be required[209,210]. The FWS as well as many state fish and game agencies offer services to help operators determine whether a given project is likely to result in a take and whether a permit is required. FWS can also provide technical assistance to help design a project so as to avoid impacts. For example, the project could be designed to minimize disturbances during nesting or mating seasons[211].

A Section 9 permit must include a habitat conservation plan (HCP) consisting of: an assessment of impacts; measures that will be undertaken to monitor, minimize and mitigate any impacts; alternative actions considered and an explanation of why they were not taken; and any additional measures that the FWS may require[212]. Mitigation measures, which are actions that reduce or address potential adverse effects of a proposed activity upon species, must be designed to address the specific needs of the species involved and be manageable and enforceable. Mitigation measures may take many forms, such as preservation (via acquisition or conservation easement) of existing habitat; enhancement or restoration of degraded or former habitat; creation of new habitats; establishment of buffer areas around existing habitats; modifications of land use practices; and restrictions on access[213].

### *State Endangered Species Protections*

All fifty states have fish and game/wildlife agencies that work in cooperation with the U. S. FWS district offices with regard to the incidental take permitting process. Many states also have their own endangered and threatened species lists that may include species not on the federal lists, and have their own requirements for protecting endangered species[214].

## Oil and Gas Operations on Public Lands

### *Federal Lands*

The U.S. Department of Interior's Bureau of Land Management (BLM) is responsible for permitting and managing most onshore oil and gas activities on federal lands. The BLM carries out its responsibility to protect the environment throughout the process of oil and gas resource exploration and development on public lands. Resource protection is considered throughout the land use planning process—when Resource Management Plans (RMPs) are prepared and when an Application for Permit to Drill (APD) is processed[215]. The BLM's inspection and enforcement and monitoring program is designed to ensure that operators comply with relevant laws and regulations as well as specific stipulations set forth during the permitting process.

Since most shale gas activity in the near future is expected to occur in the eastern U.S. basins, it is not likely that much of this development will occur on federal lands. While there are some federal lands, such as National Parks, National Forests, and military installations, these are much less extensive in the east than in the west. Where shale gas operations do occur on federal lands, BLM has a well established program for managing these activities to protect human health and the environment.

### *State Lands*

The amount of state-owned land varies considerably from state to state and each state manages these lands differently. In most states, leasing of state-owned minerals occurs through lease auctions. Since states are already set up to manage oil and gas operations within their borders, no special permitting or enforcement systems are required. Some states do have Environmental Policy Acts that require a review of environmental impacts that may result from leasing or operations on state lands or of any state action that may affect the environment.

## Other Federal Laws and Requirements that Protect the Environment

### *Comprehensive Environmental Response, Compensation, and Liability Act*

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund, was enacted by Congress on December 11, 1980. This law created a tax on the chemical and petroleum industries and provided broad federal authority to respond directly to releases or threatened releases of hazardous substances that may endanger public health or the environment. CERCLA established prohibitions and requirements concerning closed and abandoned hazardous waste sites, provided for liability of persons responsible for releases of hazardous waste at these sites, and established a trust fund to provide for cleanup when no responsible party could be identified. Over five years, $1.6 billion was collected and placed in a trust fund for cleaning up abandoned or uncontrolled hazardous waste sites.

CERCLA was amended by the Superfund Amendments and Reauthorization Act (SARA) in 1986. SARA made several changes to the Superfund program that augmented its effectiveness, provided new enforcement authorities, boosted state and citizen involvement, and increased the size of the trust fund.

In addition to the provisions for cleaning up hazardous waste sites, CERCLA requires the person in charge of a vessel or facility to immediately notify the National Response Center when there is a release of a hazardous substance in an amount equal to or greater than the reportable quantity (RQ) for that substance [CERCLA Section 103(a)]. The reportable quantity depends on the substance released.

CERCLA Section 101(14) excludes certain substances from the definition of hazardous substance, thus exempting them from CERCLA regulation. These substances include petroleum, meaning crude oil or any fraction thereof that is not specifically listed as a hazardous substance, natural gas, natural gas liquids, liquefied natural gas, and synthetic gas usable for fuel. If a release of one of these substances occurs, CERCLA notification is not required. Thus, CERCLA reporting will only apply to shale gas production and processing sites if hazardous substances other than crude oil or natural gas are spilled in reportable quantities; such are not usually present at these sites.

However, this particular exclusion applies only to CERCLA Section 103(a) reporting requirements; it does not exempt a facility from the Emergency Planning and Community Right-to-Know Act (EPCRA) Section 304 reporting requirements. A release of a petroleum product containing certain substances is potentially reportable under EPCRA Section 304 if more than an RQ of that substance is released[216].

Many states have separate requirements regarding hazardous substances. Reporting of releases of the materials exempted under CERCLA may be required under state law.

### *Emergency Planning and Community Right-to-Know Act*

Congress enacted EPCRA in 1986 to establish requirements for federal, state and local governments, tribes, and industry regarding emergency planning and "community right-to-know" reporting on hazardous and toxic chemicals. The community right-to-know provisions of EPCRA are the most relevant part of the law for shale gas producers. They help increase the public's knowledge and access to information on chemicals at individual facilities, along with their uses and potential releases into the environment.

Under Sections 311 and 312 of EPCRA, facilities manufacturing, processing, or storing designated hazardous chemicals must make Material Safety Data Sheets (MSDSs), describing the properties and health effects of these chemicals, available to state and local officials and local fire departments. Facilities must also provide state and local officials and local fire departments with inventories of all on-site chemicals for which MSDSs exist. Information about chemical inventories at facilities and MSDSs must be available to the public. Facilities that store over 10,000 pounds of hazardous chemicals are subject to this requirement. Any hazardous chemicals above the threshold stored at shale gas production and processing sites must be reported in this manner.

Section 313 of EPCRA authorizes EPA's Toxics Release Inventory (TRI), which is a publicly available database that contains information on toxic chemical releases and waste management activities reported annually by certain industries as well as federal facilities. EPA issues a list of industries that must report releases for the database. To date, EPA has not included oil and gas extraction as an industry that must report under TRI. This is not an exemption in the law. Rather it is a decision by EPA that this industry is not a high priority for reporting under TRI. Part of the rationale for this decision is based on the fact that most of the information required under TRI is already reported by producers to state agencies that make it publicly available. Also, TRI reporting from the hundreds of thousands of oil and gas sites would overwhelm the existing EPA reporting system and make it difficult to extract meaningful data from the massive amount of information submitted[217, 218].

EPCRA section 304 requires reporting of releases to the environment of certain materials that are subject to this law. As noted in the section above, this requirement would apply to any releases of petroleum products that exceed reporting thresholds, even if those products are exempt from CERCLA reporting. While shale gas production facilities do not normally store the materials subject to EPCRA reporting, known as EPCRA "Extremely Hazardous Substances" and CERCLA hazardous substances, a limited number of chemicals used in the hydraulic fracturing process, such as hydrochloric acid, are classified as hazardous under CERCLA. These chemicals may be brought on site for a few days, at most, during fracturing or work-over operations. Businesses must report non-permitted releases—into the atmosphere, surface water, or groundwater—of any listed chemical above threshold amounts, known as the "reportable quantity", to federal, state, and local authorities. Therefore, while every precaution is taken to prevent chemical spills, in the event of an accidental release above the reportable quantity, a report would be made to these authorities by the operator.

### *Occupational Safety and Health Act*

Under the Occupational Safety and Health Act of 1970, employers are responsible for providing a safe and healthy workplace for their employees. The Occupational Safety and Health Administration (OSHA) promotes the safety and health of America's working men and women by setting and enforcing standards; providing training, outreach and education; establishing partnerships; and encouraging continual process improvement in workplace safety and health[219].

OSHA has developed specific standards to reduce potential safety and health hazards in the oil and gas drilling, servicing and storage industry[220]. States also have requirements that provide further worker and public safety protections.

## Summary

The U.S. has a long history of actively regulating the oil and gas industry including the shale gas industry. A comprehensive set of federal and state laws and programs regulate all aspects of shale gas exploration and production activities. Under these programs, federal, state and local agencies enforce an array of requirements designed to protect human health and the environment during drilling, production, and abandonment operations. Together, these requirements have reduced environmental risk and adverse impacts to our water, air, and land nationwide.

***A comprehensive set of federal and state laws and programs regulate all aspects of shale gas exploration and production activities.***

# ENVIRONMENTAL CONSIDERATIONS

As described in the previous sections, natural gas is an important part of the nation's energy supply. As a clean-burning, affordable and reliable source of energy, natural gas will continue to play a significant role in the energy supply picture for years to come. Unconventional sources of natural gas have become a major component of that future supply and shale gas is rapidly emerging as a critical part of that resource.

There exists an extensive framework of federal, state, and local requirements designed to manage virtually every aspect of the natural gas development process. These regulatory efforts are primarily led by state agencies and include such things as ensuring conservation of gas resources, prevention of waste, and protection of the rights of both surface and mineral owners while protecting the environment[221]. As part of their environmental protection mission, state agencies are responsible for safeguarding public and private water supplies, preserving air quality, addressing safety, and ensuring that wastes from drilling and production are properly contained and disposed of[222].

In order to make sound decisions about future shale gas development, it is important to understand the process of drilling and producing shale gas wells (Exhibit 28) and the attendant environmental considerations. A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective BMPs, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Many of the human and environmental considerations associated with shale gas production are common to all oil and gas development. However, the horizontal drilling and hydraulic fracturing that have become the standard for modern shale gas development bring with them new considerations as well as new ways to reduce impacts. As shale gas development has spread into more densely populated areas, new challenges have been encountered and new technologies and practices have been developed to meet these challenges. In addition, collaborations between industry, regulators and the public have created innovative environmental solutions to problems that at first seemed insurmountable.

***Collaborations between industry, regulators and the public have created innovative environmental solutions to problems that at first seemed insurmountable.***

One consideration associated with traditional gas development has been the surface disturbance required for access roads and well pads. As described in greater detail below, horizontal drilling provides a means to significantly reduce surface disturbance and a host of related concerns.

## EXHIBIT 28: PROCESS OF SHALE GAS DEVELOPMENT (DURATION)

***Mineral Leasing***

*Companies negotiate a private contract or lease that allows mineral development and compensates the mineral owners. Lease terms vary and can contain stipulations or mitigation measures pertinent to protect various resources. (Several weeks to years)*

***Permits***

*The operator must obtain a permit authorizing the drilling of a new well. Surveys, drilling plans, and other technical information are frequently required for a permit application. The approved permit may require site specific environmental protection measures. Other permits such as water withdrawal or injection permits may also be required. (Several weeks to months)*

***Road and Pad Construction***

*Once permits are received, roads are constructed to access the wellsite. Well pads are constructed to safely locate the drilling rig and associated equipment during the drilling process. Pits may be excavated to contain drilling fluids. (Several days to weeks)*

***Drilling and Completion***

*A drilling rig drills the well and multiple layers of steel pipe (called casing) are put into the hole and cemented in place to protect fresh water formations. (Weeks or months)*

***Hydraulic Fracturing***

*A specially designed fracturing fluid is pumped under high pressure into the shale formation. The fluid consists primarily of water along with a proppant (usually sand) and about 2% or less of chemical additives. This process creates fractures in rock deep underground that are "propped" open by the sand, which allows the natural gas to flow into the well. (Days)*

***Production***

*Once the well is placed on production, parts of the wellpad that are no longer needed for future operations are reclaimed. The gas is brought up the well, treated to a useable condition, and sent to market. (Interim Reclamation: days; Production: years)*

***Workovers***

*Gas production usually declines over the years. Operators may perform a workover which is an operation to clean, repair and maintain the well for the purposes of increasing or restoring production. Multiple workovers may be performed over the life of a well. (Several days to weeks)*

***Plugging and Abandonment/Reclamation***

*Once a well reaches its economic limit, it is plugged and abandoned according to State standards. The disturbed areas, including well pads and access roads, are reclaimed back to the native vegetation and contours or to conditions requested by the surface owner. (Reclamation Activity: Days; Full Restoration: Years)*

Another set of considerations associated with traditional oil and gas development are the conflicts that arise from split estates. In some instances mineral rights and surface rights are not owned by the same party. This is referred to as "split estate" or "severed minerals". The condition of split estate is more prevalent in western states where the federal government owns much of the mineral rights[223]. In the mid-west and eastern states, where shale gas development resources are more prevalent, only 4% of the lands are associated with a federal split estate[224]. However, these same areas frequently have private-private split estate scenarios where the surface owner differs from the mineral estate owner. In these cases the mineral owner may be another individual or a business enterprise such as a coal company.

***It is important to understand that surface owners who do not own minerals rights are still afforded certain protections.***

A split-estate situation, regardless of its nature, can result in conflicts—especially in areas where active mineral resource development is not commonplace. Land-owners can be surprised to find that the mineral lease holder is entitled to reasonable use of the land surface even though they do not own the surface. However, it is important to understand that surface owners who do not own minerals rights are still afforded certain protections. If the mineral owner does not own the surface where drilling will occur, a separate agreement may be negotiated (in some states it is required) with the land owner to ensure that he or she is compensated for the use of the land and to set requirements for reclaiming the land when operations are complete[225].

Shale gas development within or near existing communities has created challenges for production companies. New technologies have generally allowed these challenges to be met successfully. In some cases, a combination of modern shale gas technologies and the innovative use of BMPs has been required to allow development to continue without compromising highly valued community resources.

In one instance, Chesapeake Energy Corporation constructed a well pad near a popular Fort Worth community area, known as the Trinity Trail System, to develop natural gas from the Barnett Shale. The Trinity Trail System is located on private land and consists of a 35-mile network of paved and natural surface pathways. The drilling pad was constructed approximately 200 feet from one portion of the trail. During the initial planning stages, proposed use of this land for development of natural gas was met with significant opposition by the public. Maintaining healthy populations of upland hardwood forest habitat was important to the community because such woodlots are rare in urban settings. To address the concerns of the community, the company sponsored public meetings and opinion surveys; provided landscape plans; planted trees and shrubs; and enhanced the general area by improving irrigation and lowering maintenance requirements. The well pad was specifically designed to be as small as possible in order to reduce the well's footprint. Preventative construction practices were used that helped to preserve many of the existing trees. The construction zone was isolated from view using a 16-ft barrier fence with sound baffling. This approach benefitted both parties: the company was able to produce the shale gas, important community resources were protected, and at no point in the process was any portion of the trail closed[226].

The following discussions describe the general process of development with emphasis on the horizontal drilling and hydraulic fracturing technologies that are the hallmarks of modern shale gas production. The section also describes the environmental considerations that accompany shale gas development and the technologies and practices that are in place to prevent or minimize impacts.

**EXHIBIT 29: HORIZONTAL AND VERTICAL WELL COMPLETIONS**

*Source: John Perez, Copyright ©, 2008*

## Horizontal Wells

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells (Exhibit 29). The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature[227,228,229]. The technologies utilized by operators to drill shale gas wells are similar to the drilling techniques that have been industry standards for drilling of conventional gas wells. Both horizontal drilling and hydraulic fracturing are established technologies with significant track records; horizontal drilling dates back to the 1930s and hydraulic fracturing has a history dating back to the 1950s[230]. The key difference between a shale gas well and a conventional gas well is the reservoir stimulation (large-scale hydraulic fracturing) approach performed on shale gas wells[231].

The evolution of the Barnett Shale play toward favoring horizontal wells resulted from improvements in the technology combined with the economic benefits of the greater reservoir exposure that a horizontal well provides over a vertical well. While both well types may be used to recover the resource, shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well

***Both horizontal drilling and hydraulic fracturing are established technologies with significant track records; horizontal drilling dates back to the 1930s and hydraulic fracturing has a history dating back to the 1950s.***

economics[232]. Exhibit 29 illustrates how horizontal drilling provides more exposure to a formation than does a vertical well. For example, in the Marcellus Shale in Pennsylvania, a vertical well may be exposed to as little as 50 ft of formation while a horizontal well may have a lateral wellbore extending in length from 2,000 to 6,000 ft within the 50- to 300-ft thick formation[233]. This increase in reservoir exposure creates a number of advantages over vertical wells drilling.

There are a wide range of factors that influence the choice between a vertical or horizontal well. While vertical wells may require less capital investment on a per well basis, production is often less economical. A vertical well may cost as much as $800,000 (excluding pad and infrastructure) to drill compared to a horizontal well that can cost $2.5 million or more (excluding pad and infrastructure)[234].

***Reducing Surface Disturbance***

*Source: ALL Consulting, 2008*
*Active Drilling Rig in the Barnett Shale Play*

Complete development of a 1-square mile section could require 16 vertical wells each located on a separate well pad. Alternatively, six to eight horizontal wells (potentially more), drilled from only one well pad, could access the same reservoir volume, or even more[235]. The low natural permeability of shale requires vertical wells to be developed at closer spacing intervals than conventional gas reservoirs in order to effectively manage the resource. This can result in initial development of vertical wells at spacing intervals of 40 acres per well, or less, to efficiently drain the gas resources from the tight shale reservoirs. In addition, horizontal drilling can significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat fragmentation, impacts to the public, and the overall environmental footprint. Devon Energy Corporation reports that the use of horizontal wells in the Barnett Shale has allowed the company to replace 3 or 4 vertical wells with a single horizontal well. While it is too early to determine the final well spacing that will most efficiently recover the gas resource in all basins, experience to date indicates that the use of horizontal well technology will significantly decrease the total environmental disturbance.

Exhibit 11 includes data on well spacing for some of the developing shale gas basins. Using this data it is possible to compare the development of a typical 640-acre (1 square mile) area with vertical versus horizontal wells. The spacing interval for vertical wells in the gas shale plays averages 40 acres per well for initial development. The spacing interval for horizontal wells is likely to be approximately 160 acres per well. Therefore, a 640-acre section of land could be developed with a total of 16 vertical wells, each on its own individual well pad, or by as few as 4 horizontal wells all drilled from a single multi-well drilling pad. Analysis performed in 2008 for the U.S. Department of the Interior estimated that a shallow vertical gas well completed in the Fayetteville Shale in Arkansas would have a 2.0-acre well pad, 0.10 miles of road and 0.55 miles of utility corridor, resulting in a total of 4.8 acres of disturbance per well[236]. The same source identified a horizontal well pad in Arkansas as occupying approximately 3.5 acres plus roads and utilities, resulting in a total of 6.9 acres. If multiple horizontal wells are completed from a single well pad it may require the pad to be enlarged slightly. Estimating that this enlargement will result in a 0.5-acre increase, the 4-well horizontal pad with roads and utilities would disturb an estimated total of 7.4 acres, while the 16 vertical wells would disturb approximately 77 acres. In this example, 16 vertical wells would disturb more than 10 times the area of 4 horizontal wells to produce the same resource volume. This difference in development footprint when considered in terms of both rural and urban development scenarios highlights the desire for operators to move toward horizontal development of gas shale plays.

### *Reducing Wildlife Impacts*

Research has documented that activities associated with gas development can affect wildlife and its habitat during the exploration, development, operations, and abandonment phases[237]. The development of shale gas utilizing horizontal wells and multi-well pads not only reduces surface area disturbances by reducing the total number of wells drilled and well pad sites constructed, but also results in fewer roadways and utility corridors. This overall reduction in a project's footprint results in significantly less habitat disturbance while allowing for more operational flexibility. Furthermore, by drilling underneath sensitive areas such as wetlands, areas near streams and rivers and wilderness habitats, gas can be produced without disturbing some of these resources. This ability to reduce surface disturbance is especially important in certain critical habitats. For example, certain portions of New York (e.g., Catskill Park, the Shawangunk Ridge, the Hudson Highlands and the Poconos) are dominated by hardwood forests, which are important wildlife habitats that are susceptible to fragmentation[238].

*Source: WVSORO*

*Drilling Rig in Rural Upshur County, West Virginia*

In addition, state regulations and, in some cases, local ordinances include stipulations dictating operational restrictions to provide added protection for wildlife or sensitive resources. In the city of Flower Mound, Texas, ordinances have been adopted to protect the surface resources and allow for future growth of the community without detracting from the land value or sense of community. These ordinances prevent construction in or near streams or rivers, floodplains and sensitive upland forest to protect wildlife species and their associated habitats.

At the state level, special plans or waivers are required when surface use actions may affect threatened or endangered species. Such waivers must demonstrate that contemplated disturbances will not adversely impact the species in question. In Pennsylvania, wildlife are further protected on state lands (by the Pennsylvania Game Commission) by using lease agreements that require, whenever feasible, the use of existing timber and maintenance roads to access wells and avoidance of areas such as wetlands and unique and critical habitats for threatened or endangered species[239].

When disturbances to wildlife habitat are unavoidable, energy companies mitigate land disturbances by implementing land reclamation practices to restore disturbed land to original conditions. In general, reclamation practices (or mitigation measures) designed to protect and maintain wildlife will depend on project features, regional characteristics, and the potentially affected species. However, because technologies associated with modern shale gas development can reduce impacts in the first place, the need for additional protective restoration measures may also be reduced. Regardless of the situation, the timely reclamation of disturbed lands (e.g., re-seeding, land contouring, and re-vegetating) can minimize short and long-term disturbances to natural habitats[240].

### *Reducing Community Impacts*

States, local governments, and industry can work together in the initial planning phase of development to minimize long term effects and to address citizen concerns such as traffic congestion, damage to roads, dust, and noise [241].The process of shale gas development, especially drilling and hydraulic fracturing, can create short-term increases in traffic volume, dust and noise. These nuisance impacts are usually limited to the initial 20- to 30-day drilling and completion period[242]. Along with increases in traffic volume, damage to road surfaces can occur if design parameters for traffic volume and weight loads are exceeded. Where these effects are an issue, developers have worked with authorities to adjust work schedules to help alleviate congestion; water unpaved roads to reduce dust; and adjust timing of some operations and install special sound barriers to reduce noise for nearby residents. When feasible, developers can also use avoidance practices to help minimize traffic congestion on heavily traveled roads. In the Barnett Shale play around the Dallas-Fort Worth International Airport, operators have constructed permanent pipelines to transfer produced water from well sites to disposal facilities, thereby

*Source: Parker County Commissioner's Office*

*Tanker Trucks in Parker County, Texas*

reducing traffic and potential damage to roads[243]. When these practices are coupled with the benefits of multiple directional wells from fewer pads, the number of access roads and associated traffic can be further reduced.

In many cases, developers have negotiated to compensate local municipalities for road damage that does occur as a result of their activities. Alternatively, they may negotiate road maintenance and repair agreements to ensure that damage to roadways are repaired and that the cost is absorbed by the drilling enterprises[244]. The Perryman Group, in their 2007 study of the Barnett Shale play, noted that although traffic volume is a legitimate concern in the area, developers were effectively addressing the issue through maintenance agreements so that road repairs do not adversely affect local taxpayers[245].

From a traffic perspective, members of the public or local municipalities often have the ability to limit traffic volume in residential areas by developing restrictions in neighborhood lease agreements or by developing ordinances that prevent road construction in certain areas, respectively. In urban areas these agreements can be used to coordinate local traffic patterns to minimize congestion, control speed limits to address safety concerns, and specify weight zones to reduce road damage.

With continued advances in technologies, modern developers are afforded a higher level of drilling flexibility than in the past. This provides producers with the ability to adjust their operational plans allowing them to access drilling locations that would otherwise be inaccessible. Although drilling circumstances vary by geologic region and well location, in many cases, shale gas plays are being developed with both vertically and horizontally drilled wells (Exhibit 29). Based on the current development activities of active gas shale basins, horizontal drilling has become the preferred method of drilling in most shale gas plays. Horizontal wells have also been used in many areas of the country to remotely access natural gas resources beneath existing infrastructure, buildings, environmentally sensitive areas, or other features that would prevent the use of vertical wells. The development of the Barnett Shale near Dallas-Fort Worth International Airport is a prime example of how development of urban areas is possible with horizontal wellbores[246].


*Source: ALL Consulting, 2008*

*Shale Gas Activity at Dallas-Fort Worth International Airport*

Changes in practices during the drilling and completion of shale gas wells have evolved from the Barnett Shale play near Dallas-Fort Worth International Airport and other urban areas surrounding the airport. Development practices there have been altered to suit local ordinances implemented to lessen community impacts and protect environmental resources. These ordinances include detailed setbacks from residences, roadways, churches, and schools, and means to control visual and noise impacts including the required use of directional lighting[247]. This results in the use of BMPs for sound barriers and lighting. Typically, drilling operations in rural gas development areas continue around the clock until the well is completed. When these same operations moved into the urban areas around the cities of Arlington, Burleson, Cleburne, Fort Worth, Joshua and North Richland Hills, specific ordinances were developed requiring additional permitting, well set backs from properties, day-time and night-time noise limits, and directional lighting[248]. Directional lighting provides illumination of well sites for worker safety, directing the light downward and shielding the surrounding area to prevent illuminating neighboring residences, roads or other buildings[249].

***The purpose of ordinances and best management practices is to facilitate the development of the natural gas resource while protecting quality of life and environmental values in the surrounding areas.***

*Source : Chesapeake Energy Corporation, 2008*

*Insulation Blankets Used to Deaden Noise from Drilling Operations*

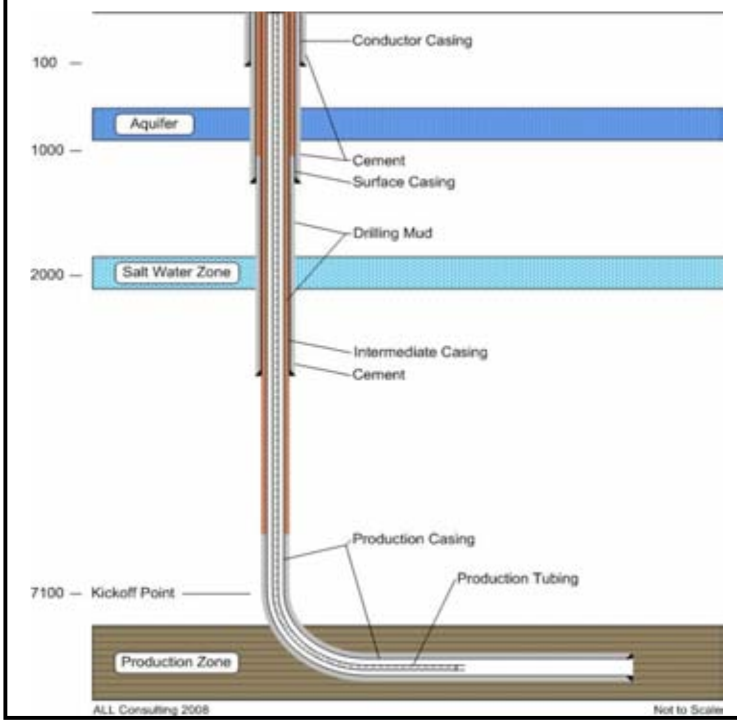
In a similar concept, these drilling rigs are also being outfitted with blanket-like enclosures that act as an acoustic barrier to reduce engine noise. Sound deadening technology is a BMP that is also being applied to reduce noises from compressor facilities in both rural and urban settings[250]. These sound barriers include developing alternative building materials with integral sound absorbing properties.

These "BMPs" are not appropriate for all operations and must be applied on a case-by-case basis. In some cases, a given BMP may actually be counter-productive. In other cases, a particular BMP may create other environmental, safety, or operational problems that must be weighed against each other. While BMPs have certain benefits in certain situations, they cannot be universally applied or required.

### *Protecting Groundwater: Casing and Cementing Programs*

State oil and gas regulatory programs place great emphasis on protecting groundwater. Current well construction requirements consist of installing multiple layers of protective steel casing and cement that are specifically designed and installed to protect fresh water aquifers and to ensure that the producing zone is isolated from overlying formations. During the drilling process, a conductor and surface casing string are set in the borehole and cemented in place. In some instances, additional casing strings may be installed; these are known as intermediate casings (Exhibit 30[251]). After each string of casing is set, and prior to drilling any deeper in the borehole, the casing is cemented to ensure a seal is provided between the casing and formation or between two strings of casing[252]. Exhibit 30 illustrates the casing and cement that may be installed in shale gas wells and highlights how the casing can be set to isolate different water-bearing zones from each other. The exhibit shows the multiple strings of casing, layers of cement and the production tubing, which are all important parts of the well completion in preventing contamination of fresh water zones and assuring that the gas resource does not flow into other, lower pressure zones around the outside of the casing rather than flowing up the well to be produced and sold.[253].

**EXHIBIT 30: CASING ZONES AND CEMENT PROGRAMS**




The conductor casing serves as a foundation for the well construction and prevents caving of surface soils. The surface casing is installed to seal off potential freshwater-bearing zones, this isolation is necessary in order to protect aquifers from drilling mud and produced fluids. As a further protection of the fresh water zones, air-rotary drilling is often used when drilling through this portion of the wellbore interval to ensure that no drilling mud comes in contact with the fresh water zone. Intermediate casings, when installed, are used to isolate non-freshwater-bearing zones from the producing wellbore. Intermediate casing may be necessary because of a naturally over-pressured zone or because of a saltwater zone located at depth. The borehole area below an intermediate casing may be uncemented until just above the kickoff point for the horizontal leg. This area of wellbore is typically filled with drilling muds.

Each string of casing serves as a layer of protection separating the fluids inside and outside of the casing and preventing each from contacting the other. Operators perform a variety of checks to ensure that the desired isolation of each zone is occurring including ensuring that the casing used has sufficient strength, and that the cement has properly bonded to the casing[254]. These checks may include acoustic cement bond logs and pressure testing to ensure the mechanical integrity of casings. Additionally, state oil and gas regulatory agencies often specify the required depth of protective casings and regulate the time that is required for cement to set prior to additional drilling. These requirements are typically based on regional conditions and are established for all wildcat wells and may be modified when field rules are designated. These requirements are instituted by the state oil and gas agency to provide protection of groundwater resources[255]. Once the casing strings are run and cemented there could be five or more layers or barriers between the inside of the production tubing and a water-bearing formation (fresh or salt).

Analysis of the redundant protections provided by casings and cements was presented in a series of reports and papers prepared for the American Petroleum Institute (API)[256] in the 1980s. These investigations evaluated the level of corrosion that occurred in Class II injection wells. Class II injection wells are used for the routine injection of water associated with oil and gas production. The research resulted in the development of a method of calculating the probability (or risk) that fluids injected into Class II injection wells could result in an impact to a USDW. This research started by evaluating data for oil and gas producing basins to determine if there were natural formation waters present that were reported to cause corrosion of well casings. The United States was divided into 50 basins, and each basin was ranked by its potential to have a casing leak resulting from such corrosion.

Detailed analysis was performed for those basins in which there was a possibility of casing corrosion[257]. Risk probability analysis provided an upper bound for the probability of the fracturing fluids reaching an underground source of drinking water. Based on the values calculated, a modern horizontal well completion in which 100% of the USDWs are protected by properly installed surface casings (and for geologic basins with a reasonable likelihood of corrosion), the probability that fluids injected at depth could impact a USDW would be between $2 \times 10^{-5}$ (one well in 200,000) and $2 \times 10^{-8}$ (one well in 200,000,000) if these wells were operated as injection wells. Other studies in the Williston basin found that the upper bound probability of injection water escaping the wellbore and reaching an underground source of drinking water is seven changes in one million well-years where surface casings cover the drinking water aquifers[258].

These values do not account for the differences between the operation of a shale gas well and the operation of an injection well. An injection well is constantly injecting fluid under pressure and thus raises the pressure of the receiving aquifer, increasing the chance of a leak or well failure. A production well is reducing the pressure in the producing zone by giving the gas and associated fluid a way out, making it less likely that they will try to find an alternative path that could contaminate a fresh water zone. Furthermore, a producing gas well would be less likely to experience a casing leak because it is operated at a reduced pressure compared to an injection well. It would be exposed to lesser volumes of potentially corrosive water flowing through the production tubing, and it would only be exposed to the pumping of fluids into the well during fracture stimulations.

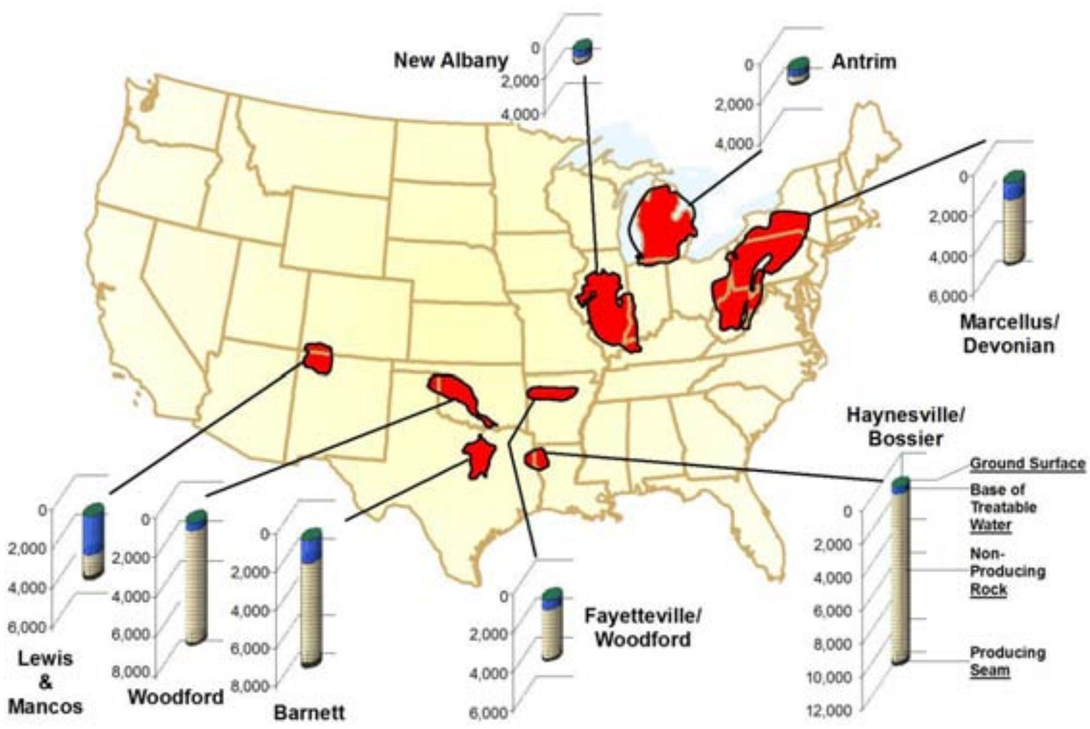
The API study included an analysis of wells that had been in operation for many years when the study was performed in the late 1980s, and does not account for advances that have occurred in equipment and applied technologies and changes to the regulations. As such, a calculation of the probability of any fluids, including hydraulic fracture fluids, reaching a USDW from a gas well would indicate an even lower probability; perhaps by as much as two to three orders of magnitude. The API report came to another important conclusion relative to the probability of the contamination of a USDW when it stated that:

> …for injected water to reach a USDW in the 19 identified basins of concern, a number of independent events must occur at the same time and go *undetected* [emphasis added]. These events include simultaneous leaks in the [production] tubing, production casing, [intermediate casing,] and the surface casing coupled with the unlikely occurrence of water moving long distances up the borehole past salt water aquifers to reach a USDW[259].

As indicated by the analysis conducted by API and others, the potential for groundwater to be impacted by injection is low. It is expected that the probability for treatable groundwater to be impacted by the pumping of fluids during hydraulic fracture treatments of newly installed, deep shale gas wells when a high level of monitoring is being performed would be even less than the 2 x $10^{-8}$ estimated by API.

In addition to the protections provided by multiple casings and cements, there are natural barriers in the rock strata that act as seals holding the gas in the target formation. Without such seals, gas and oil would naturally migrate to the earth's surface. A fundamental precept of oil and gas geology is that without an effective seal, gas and oil would not accumulate in a reservoir in the first place and so could never be tapped and produced in usable quantities. These sealing strata also act as barriers to vertical migration of fluids upward toward useable groundwater zones. Most shale gas wells (outside of those completed in the New Albany and the Antrim) are expected to be drilled at depths greater than 3,000 feet below the land surface (based on the data presented in Exhibit 11). Exhibit 31 compares estimated shallowest producible depth of the target ("pay") shale zone and the maximum base of treatable water. For any fluid present in the producing zone to reach treatable groundwater the fluid must migrate through these overlying zones.

**EXHIBIT 31: COMPARISON OF TARGET SHALE DEPTH AND BASE OF TREATABLE GROUNDWATER**




*Source: Compiled from Various Data Sources*

***A fundamental precept of oil and gas geology is that without an effective seal, gas and oil would not accumulate in a reservoir in the first place and so it could never be tapped and produced in usable quantities. These sealing strata also act as barriers to vertical migration of fluids upward toward groundwater zones.***

### *Drilling Fluids and Retention Pits*

Drilling fluids are a necessary component of the drilling process; they circulate cuttings (rock chips created as the drill bit advances through rock, much like sawdust) to the surface to clear the borehole, they lubricate and cool the drilling bit, they stabilize the wellbore (preventing cave in), and control downhole fluid pressure[260]. In order to maintain sufficient volumes of fluids onsite during drilling, operators typically use pits to store make-up water used as part of the drilling fluids. Storage pits are not used in every development situation. In the case of shale gas development, drilling operations have been occurring in both urban and rural locations, requiring that drilling practices be adapted to facilitate development in both settings. Drilling with compressed air is becoming an increasingly popular alternative to drilling with fluids due to the increased cost savings from both reduction in mud costs and the shortened drilling times as a result of air based drilling[261]. The air, like drilling mud, functions to lubricate, cool the bit, and remove cuttings. Air drilling is generally limited to low pressure formations, such as the Marcellus shale in New York[262].

*Source: ALL Consulting, 2008*

*Lined Fresh Water Supply Pit from the Marcellus Shale Development in Pennsylvania*

In rural areas, storage pits may be used to hold fresh water for drilling and hydraulic fracturing. In an urban setting, due to space limitations, steel storage tanks may be used. Tanks can also be used in a closed-loop drilling system. Closed-loop drilling allows for the re-use of drilling fluids and the use of lesser amounts of drilling fluids[263]. Closed-loop drilling systems have also been used with water-based fluids in environmentally sensitive environments in combination with air-rotary drilling techniques[264]. While closed-loop drilling has been used to address specific situations, the practice is not necessary for every well drilled. As discussed in the previous section, drilling is a regulated practice managed at the state level, and while state oil and gas agencies have the ability to require operators to vary standard practices, the agencies typically do so only when it is necessary to protect the gas resources and the environment.

In rural environments, storage pits may be used to hold water. They are typically excavated containment ponds that, based on the local conditions and regulatory requirements, may be lined. Pits can also be used to store additional make-up water for drilling fluids or to store water used in the hydraulic fracturing of wells.

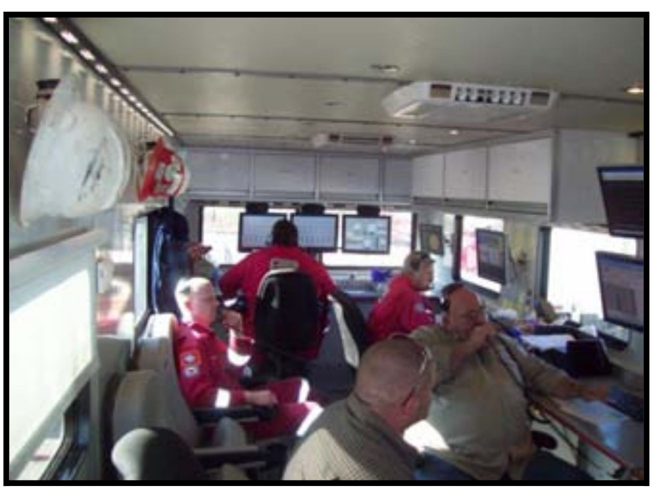
Water storage pits used to hold water for hydraulic fracturing purposes are typically lined to minimize the loss of water from infiltration (notice the black synthetic liner in the accompanying photograph). Water storage pits are becoming an important tool in the shale gas industry because the drilling and hydraulic fracturing of these wells often requires significant volumes of water as the base fluid for both purposes[265].

## Hydraulic Fracturing

The other technological key to the economic recovery of shale gas is hydraulic fracturing. Hydraulic fracturing is a formation stimulation practice used to create additional permeability in a producing formation, thus allowing gas to flow more readily toward the wellbore[266,267]. Hydraulic fracturing can be used to overcome natural barriers to the flow of fluids (gas or water) to the wellbore. Such barriers may include naturally low permeability common in shale formations or reduced permeability resulting from near wellbore damage during drilling activities[268].

***Stimulations are optimized to ensure that fracture development is confined to the target formation.***

Hydraulic fracturing involves the pumping of a fracturing fluid into a formation at a calculated, predetermined rate and pressure to generate fractures or cracks in the target formation. For shale gas development, fracture fluids are primarily water-based fluids mixed with additives which help the water to carry sand proppant into the fractures. The sand proppant is needed to "prop" open the fractures once the pumping of fluids has stopped. Once the fracture has initiated, additional fluids are pumped into the wellbore to continue the development of the fracture and to carry the proppant deeper into the formation. The additional fluids are needed to maintain the downhole pressure necessary to accommodate the increasing length of opened fracture in the formation. Each rock formation has inherent natural variability resulting in different fracture pressures for different formations. The process of designing hydraulic fracture treatments involves identifying properties of the target formation including fracture pressure, and the desired length of fractures. The following discussion addresses some of the processes involved in the design of a hydraulic fracture stimulation of a shale gas formation.



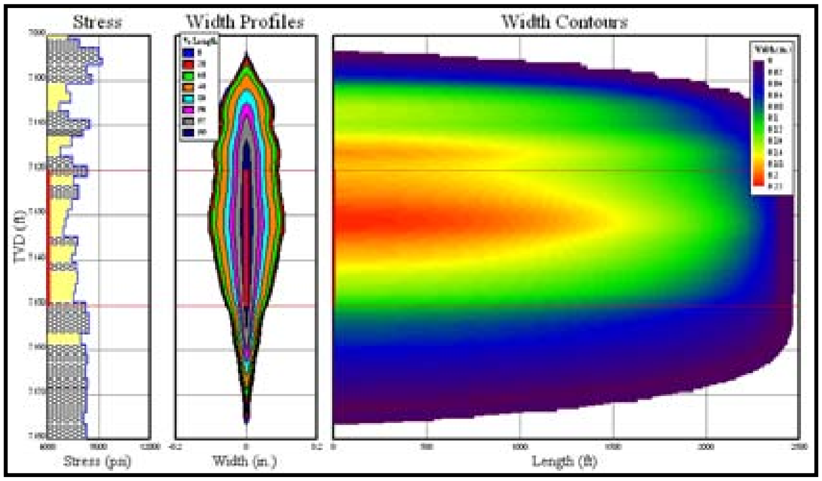
*Source: ALL Consulting, 2008*

*A Fracture Stimulation Is Closely Monitored by Many Specialists (Fayetteville Shale - Arkansas)*

### *Fracture Design*

Modern formation stimulation practices are sophisticated, engineered processes designed to emplace fracture networks in specific rock strata[269]. A hydraulic fracture treatment is a controlled process designed to the specific conditions of the target formation (thickness of shale, rock fracturing characteristics, etc.). Understanding the *in-situ* reservoir conditions present and their dynamics is critical to successful stimulations. Hydraulic fracturing designs are continually refined to optimize fracture networking and maximize

**EXHIBIT 32: EXAMPLE OUTPUT OF A HYDRAULIC FRACTURE STIMULATION MODEL**




*Source: Chesapeake, 2008*

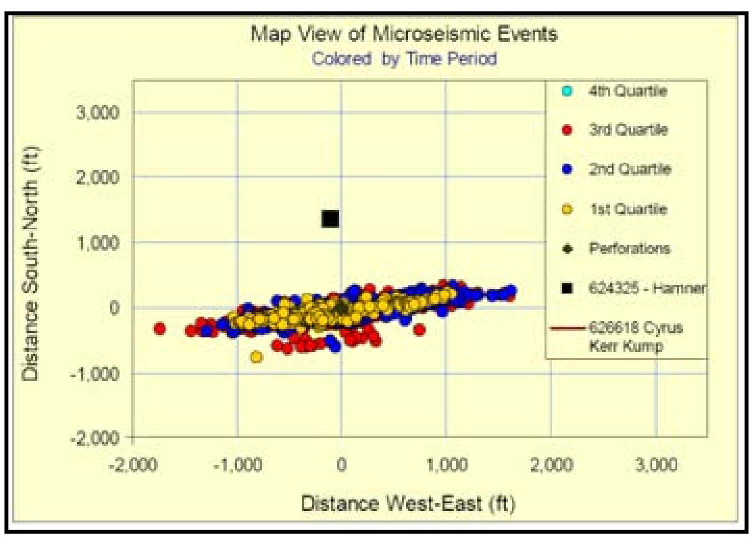
gas production. While the concepts and general practices are similar, the details of a specific fracture operation can vary substantially from basin to basin and from well to well.

Fracture design can incorporate many sophisticated and state-of-the-art techniques to accomplish an effective, economic and highly successful fracture stimulation. Some of these techniques include modeling, microseismic fracture mapping, and tilt-meter analysis.

A computer model can be used to simulate hydraulic fracturing designs[270]. This approach helps maximize effectiveness and economically design a treatment event. The modeling programs allow geologists and engineers to modify the design of a hydraulic fracture treatment and evaluate the height, length, and orientation of potential fracture development (Exhibit 32)[271]. These simulators also allow the designers to use the data gathered during a fracture stimulation to evaluate the success of the fracture job performed. From these data and analyses, engineers can optimize the design of future fracture stimulations.

Additional advances in hydraulic fracturing design target analysis of hydraulic fracture treatments through technologies such as microseismic fracture mapping (Exhibit 33[272]) and tilt measurements[273]. These technologies can be used to define the success and orientation of the fractures created, thus providing the engineers with the ability to manage the resource through the strategic placement of additional wells, taking advantage of the natural reservoir conditions and expected fracture results in new wells.

**EXHIBIT 33: MAPPING OF MICROSEISMIC EVENTS**




*Source: Oilfield Service Company, 2008*

As more formation-specific data are gathered, service companies and operators can optimize fracture patterns. Operators have strong economic incentives to ensure that fractures do not propagate beyond

***Operators have strong economic incentives to ensure that fractures do not propagate beyond the target formation and into adjacent rock strata.***

the target formation and into adjacent rock strata[274]. Allowing the fractures to extend beyond the target formation would be a waste of materials, time, and money. In some cases, fracturing outside o f the target formation could potentially result in the loss of the well and the associated gas resource. Fracture growth outside of the target formation can result in excess water production from bounding strata. Having to pump and handle excess water increases production costs, negatively impacting well economics. This is a particular concern in the Barnett Shale of Texas where the underlying Ellenberger Group limestones are capable of yielding significant formation water.

### *Fracturing Process*

Hydraulic fracturing of horizontal shale gas wells is performed in stages. Lateral lengths in horizontal wells for shale gas development may range from 1,000 feet to more than 5,000 feet. Because of the length of exposed wellbore, it is usually not possible to maintain a downhole pressure sufficient to stimulate the entire length of a lateral in a single stimulation event[275]. Because of the lengths of the laterals, hydraulic fracture treatments of horizontal shale gas wells are usually performed by isolating smaller portions of the lateral. The fracturing of each portion of the lateral wellbore is called a stage. Stages are fractured sequentially beginning with the section at the farthest end of the wellbore, moving uphole as each stage of the treatment is completed until the entire lateral well has been stimulated[276]. Horizontal wells in the various gas shale basins may be treated using two or more stages to fracture the entire perforated interval of the well. Each stage of a horizontal well fracture treatment is similar to a fracture treatment for a vertical shale gas well.

For each stage of a fracture treatment, a series of different volumes of fracture fluids, called sub-stages, with specific additives and proppant concentrations, is injected sequentially. Exhibit 34[277] presents an example of the sub-stages of a single-stage hydraulic fracture treatment for a well completed in the Marcellus Shale[278]. This is a single-stage treatment typical of what might be performed on a vertical shale well or for each stage of a multi-stage horizontal well treatment. The total volume of the sub-stages in Exhibit 34 is 578,000 gallons. If this were one stage of a four-stage horizontal well, the entire fracture operation would require approximately four times this amount, or 2.3 million gallons of water.

Before operators or service companies perform a hydraulic fracture treatment of a well (vertical or horizontal), a series of tests is performed. These tests are designed to ensure that the well, well equipment and hydraulic fracturing equipment are in proper working order and will safely withstand the application of the fracture treatment pressures and pump flow rates. The tests start with the testing of well casings and cements during the drilling and well construction process. Testing continues with pressure testing of hydraulic fracturing equipment prior to the fracture treatment process[279]. It should be noted that construction requirements for wells are mandated by state oil and gas regulatory agencies to ensure that a well is protective of water resources and is safe for operation.

**EXHIBIT 34: EXAMPLE OF A SINGLE STAGE OF A SEQUENCED HYDRAULIC FRACTURE TREATMENT**

| Hydraulic Fracture Treatment Sub-Stage | Volume (gallons) | Rate (gal/min) |
|---|---|---|
| Diluted Acid (15%) | 5,000 | 500 |
| Pad | 100,000 | 3,000 |
| Prop 1 | 50,000 | 3,000 |
| Prop 2 | 50,000 | 3,000 |
| Prop 3 | 40,000 | 3,000 |
| Prop 4 | 40,000 | 3,000 |
| Prop 5 | 40,000 | 3,000 |
| Prop 6 | 30,000 | 3,000 |
| Prop 7 | 30,000 | 3,000 |
| Prop 8 | 20,000 | 3,000 |
| Prop 9 | 20,000 | 3,000 |
| Prop 10 | 20,000 | 3,000 |
| Prop 11 | 20,000 | 3,000 |
| Prop 12 | 20,000 | 3,000 |
| Prop 13 | 20,000 | 3,000 |
| Prop 14 | 10,000 | 3,000 |
| Prop 15 | 10,000 | 3,000 |
| Flush | 13,000 | 3,000 |

**Notes**:

Volumes are presented in gallons (42 gals = one barrel, 5,000 gals = ~120 bbls).
Rates are expressed in gals/minute, 42 gals/minute = 1 bbl/min, 500 gal/min = ~12 bbls/min.
Flush volumes are based on the total volume of open borehole, therefore as each stage is completed the volume of flush decreases as the volume of borehole is decreased.
Total amount of proppant used is approximately 450,000 pounds

*Source: Arthur et al., 2008*

After the testing of equipment has been completed, the hydraulic fracture treatment process begins. The sub-stage sequence is usually initiated with the pumping of an acid treatment. This acid treatment helps to clean the near-wellbore area which can be "damaged" (pores and pore throats become plugged with drilling mud or casing cement) as a result of the drilling and well installation process. The next sequence after the acid treatment is a slickwater pad, which is a water-based fracturing fluid mixed with a friction reducing agent. The pad is a volume of fracturing fluid large enough to effectively fill the wellbore and the open formation area. The slickwater pad helps to facilitate the flow and placement of the proppant further into the fracture network.

*Source: Chesapeake Energy Corporation, 2008*

*Hydraulic Fracturing of a Marcellus Shale Well, West Virginia*

After the pad is pumped, the first proppant sub-stage, combining a large volume of water with fine mesh sand is pumped. The next several sub-stagesin the stage increase the volume of fine-grained proppant while the volume of fluids pumped are decreased incrementally from 50,000 gallons (gals) to 30,000 gals. This fine-grained proppant is used because the finer particle size is capable of being carried deeper into the developed fractures[280]. In this example, the fine proppant sub-stages are followed by eight sub-stages of a coarser proppant with volumes from 20,000 gals to 10,000 gals. After the completion of the final sub-stage of coarse proppant, the well and equipment are flushed with a volume of freshwater sufficient to remove excess proppants from the equipment and the wellbore.

Hydraulic fracturing stimulations are overseen continuously by operators and service companies to evaluate and document the events of the treatment process. Every aspect of the fracture stimulation process is carefully monitored, from the wellhead and downhole pressures to pumping rates and density of the fracturing fluid slurry. The monitors

***Every aspect of the fracture stimulation process is carefully monitored.***

also track the volumes of each additive and the water used, and ensure that equipment is functioning properly. For a 12,000-bbl (504,000-gallon) fracture treatment of a vertical shale gas well there may be between 30 and 35 people on site monitoring the entire stimulation process.

The staging of multiple fracture treatments along the length of the lateral leg of the horizontal well allows the fracturing process to be performed in a very controlled manner. By fracturing discrete intervals of the lateral wellbore, the operator is able to make changes to each portion of the completion zone to accommodate site-specific changes in the formation. These site-specific variations may include variations in shale thickness, presence or absence of natural fractures, proximity to another wellbore fracture system, and boreholes that are not centered in the formation.

### *Fracturing Fluids and Additives*

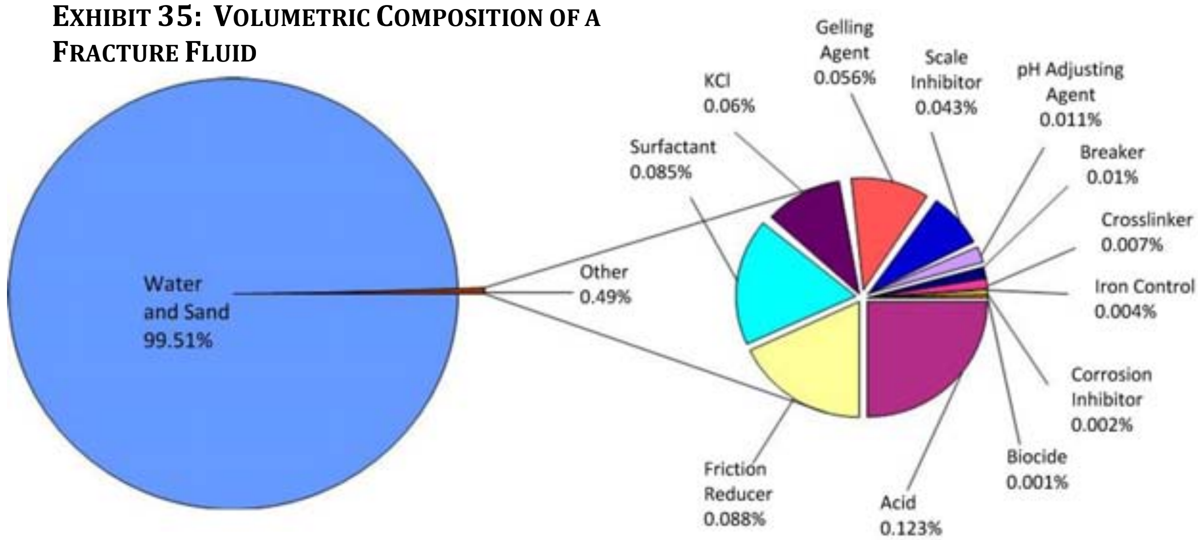
As described above, the current practice for hydraulic fracture treatments of shale gas reservoirs is to apply a sequenced pumping event in which millions of gallons of water-based fracturing fluids mixed with proppant materials are pumped in a controlled and monitored manner into the target shale formation above fracture pressure[281].

The fracturing fluids used for gas shale stimulations consist primarily of water but also include a variety of additives. The number of chemical additives used in a typical fracture treatment varies depending on the conditions of the specific well being fractured. A typical fracture treatment will use very low concentrations of between 3 and 12 additive chemicals depending on the characteristics of the water and the shale formation being fractured. Each component serves a specific, engineered purpose[282]. The predominant fluids currently being used for fracture treatments in the gas shale plays are water-based fracturing fluids mixed with friction-reducing additives (called slickwater)[283].

The addition of friction reducers allows fracturing fluids and proppant to be pumped to the target zone at a higher rate and reduced pressure than if water alone were used. In addition to friction reducers, other additives include: biocides to prevent microorganism growth and to reduce bio-fouling of the fractures; oxygen scavengers and other stabilizers to prevent corrosion of metal pipes; and acids that are used to remove drilling mud damage within the near-wellbore area[284]. These fluids are used not only to create the fractures in the formation but also to carry a propping agent (typically silica sand) which is deposited in the induced fractures.

Exhibit 35[285] demonstrates the volumetric percentages of additives that were used for a nine-stage hydraulic fracturing treatment of a Fayetteville Shale horizontal well. The make-up of fracturing fluid varies from one geologic basin or formation to another. Evaluating the relative volumes of the components of a fracturing fluid reveals the relatively small volume of additives that are present. The additives depicted on the right side of the pie chart represent less than 0.5% of the total fluid volume. Overall the concentration of additives in most slickwater fracturing fluids is a relatively consistent 0.5% to 2% with water making up 98% to 99.5%.

**EXHIBIT 35: VOLUMETRIC COMPOSITION OF A FRACTURE FLUID**




*Source: ALL Consulting based on data from a fracture operation in the Fayetteville Shale, 2008*

Because the make-up of each fracturing fluid varies to meet the specific needs of each area, there is no one-size-fits-all formula for the volumes for each additive. In classifying fracturing fluids and their additives it is important to realize that service companies that provide these additives have developed a number of compounds with similar functional properties to be used for the same purpose in different well environments. The difference between additive formulations may be as small as a change in concentration of a specific compound. Although the hydraulic fracturing industry may have a number of compounds that can be used in a hydraulic fracturing fluid, any single fracturing job would only use a few of the available additives. For example, in Exhibit 35 there are 12 additives used, covering the range of possible functions that could be built into a fracturing fluid. It is not uncommon for some fracturing recipes to omit some compound categories if their properties are not required for the specific application.

Most industrial processes use chemicals and almost any chemical can be hazardous in large enough quantities or if not handled properly. Even chemicals that go into our food or drinking water can be hazardous. For example, drinking water treatment plants use large quantities of chlorine. When used and handled properly, it is safe for workers and near-by residents and provides clean, safe drinking water for the community. Although the risk is low, the potential exists for unplanned releases that could have serious effects on human health and the environment. By the same token, hydraulic fracturing uses a number of chemical additives that could be hazardous, but are safe when properly handled according to requirements and long-standing industry practices. In addition, many of these additives are common chemicals which people regularly encounter in everyday life.

**EXHIBIT 36: FRACTURING FLUID ADDITIVES, MAIN COMPOUNDS, AND COMMON USES.**

| Additive Type | Main Compound(s) | Purpose | Common Use of Main Compound |
|---|---|---|---|
| Diluted Acid (15%) | Hydrochloric acid or muriatic acid | Help dissolve minerals and initiate cracks in the rock | Swimming pool chemical and cleaner |
| Biocide | Glutaraldehyde | Eliminates bacteria in the water that produce corrosive byproducts | Disinfectant; sterilize medical and dental equipment |
| Breaker | Ammonium persulfate | Allows a delayed break down of the gel polymer chains | Bleaching agent in detergent and hair cosmetics, manufacture of household plastics |
| Corrosion Inhibitor | N,n-dimethyl formamide | Prevents the corrosion of the pipe | Used in pharmaceuticals, acrylic fibers, plastics |
| Crosslinker | Borate salts | Maintains fluid viscosity as temperature increases | Laundry detergents, hand soaps, and cosmetics |
| Friction Reducer | Polyacrylamide | Minimizes friction between the fluid and the pipe | Water treatment, soil conditioner |
| | Mineral oil | | Make-up remover, laxatives, and candy |
| Gel | Guar gum or hydroxyethyl cellulose | Thickens the water in order to suspend the sand | Cosmetics, toothpaste, sauces, baked goods, ice cream |
| Iron Control | Citric acid | Prevents precipitation of metal oxides | Food additive, flavoring in food and beverages; Lemon Juice ~7% Citric Acid |
| KCl | Potassium chloride | Creates a brine carrier fluid | Low sodium table salt substitute |
| Oxygen Scavenger | Ammonium bisulfite | Removes oxygen from the water to protect the pipe from corrosion | Cosmetics, food and beverage processing, water treatment |
| pH Adjusting Agent | Sodium or potassium carbonate | Maintains the effectiveness of other components, such as crosslinkers | Washing soda, detergents, soap, water softener, glass and ceramics |
| Proppant | Silica, quartz sand | Allows the fractures to remain open so the gas can escape | Drinking water filtration, play sand, concrete, brick mortar |
| Scale Inhibitor | Ethylene glycol | Prevents scale deposits in the pipe | Automotive antifreeze, household cleansers, and de-icing agent |
| Surfactant | Isopropanol | Used to increase the viscosity of the fracture fluid | Glass cleaner, antiperspirant, and hair color |

Note: The specific compounds used in a given fracturing operation will vary depending on company preference, source water quality and site-specific characteristics of the target formation. The compounds shown above are representative of the major compounds used in hydraulic fracturing of gas shales.

Exhibit 36[286] provides a summary of the additives, their main compounds, the reason the additive is used in a hydraulic fracturing fluid, and some of the other common uses for these compounds. Hydrochloric acid (HCl) is the single largest liquid component used in a fracturing fluid aside from water; while the concentration of the acid may vary, a 15% HCl mix is a typical concentration. A 15% HCl mix is composed of 85% water and 15% acid, therefore, the volume of acid is diluted by 85% with water in its stock solution before it is pumped into the formation during a fracturing treatment. Once the entire stage of fracturing fluid has been injected, the total volume of acid in an example fracturing fluid from the Fayetteville shale was 0.123%, which indicates the fluid had been diluted by a factor of 122 times before it is pumped into the formation. The concentration of this acid will only continue to be diluted as it is further dispersed in additional volumes of water that may be present in the subsurface. Furthermore, if this acid comes into contact with carbonate minerals in the subsurface, it would be neutralized by chemical reaction with the carbonate minerals producing water and carbon dioxide as a byproduct of the reaction.

## Water Availability

The drilling and hydraulic fracturing of a horizontal shale gas well may typically require 2to 4 million gallons of water[287], with about 3 million gallons being most common. It should be noted that the volume of water needed may vary substantially between wells. In addition the volume of water needed per foot of wellbore appears to be decreasing as technologies and methods improve over time. Exhibit 37[288] presents a table of estimated per-well water needs for four shale gas plays currently being developed.

**EXHIBIT 37: ESTIMATED WATER NEEDS FOR DRILLING AND FRACTURING WELLS IN SELECT SHALE GAS PLAYS**

| Shale Gas Play | Volume of Drilling Water per well (gal) | Volume of Fracturing Water per well (gal) | Total Volumes of Water per well (gal) |
|---|---|---|---|
| Barnett Shale | 400,000 | 2,300,000 | 2,700,000 |
| Fayetteville Shale | 60,000* | 2,900,000 | 3,060,000 |
| Haynesville Shale | 1,000,000 | 2,700,000 | 3,700,000 |
| Marcellus Shale | 80,000* | 3,800,000 | 3,880,000 |

* Drilling performed with an air "mist" and/or water-based or oil-based muds for deep horizontal well completions.
Note: These volumes are approximate and may vary substantially between wells.

*Source: ALL Consulting from discussions with various operators, 2008*

Water for drilling and hydraulic fracturing of these wells frequently comes from surface water bodies such as rivers and lakes, but can also come from ground water, private water sources, municipal water, and re-used produced water. Most of the producing shale gas basins occur in areas with moderate to high levels of annual precipitation as shown in Exhibit 38[289]. However, even in areas of high precipitation, due to growing populations, other industrial water demands, and seasonal variation in precipitation, it can be difficult to meet the needs of shale gas development and still satisfy regional needs for water.

*Source: ALL Consulting, 2008*

*Little Red River, Arkansas*

While the water volumes needed to drill and stimulate shale gas wells are large, they generally represent a small percentage of the total water resource use in the shale gas basins. Calculations indicate that water use will range from less than 0.1% to 0.8% by basin[290]. This volume is small in terms of the overall surface water budget for an area; however, operators need this water when drilling activity is occurring, requiring that the water be procured over a relatively short period of time. Water withdrawals during periods of low stream flow could affect fish and other aquatic life, fishing and other recreational activities, municipal water supplies, and other industries such as power plants. To put shale gas water use in perspective, the consumptive use of fresh water for electrical generation in the Susquehanna River Basin alone is nearly 150 million gallons per day, while the projected total demand for peak Marcellus Shale activity in the same area is 8.4 million gallons per day[291].

One alternative that states and operators are pursuing is to make use of seasonal changes in river flow to capture water when surface water flows are greatest. Utilizing seasonal flow differences allows planning of withdrawals to avoid potential impacts to municipal drinking water supplies or to aquatic or riparian communities. In the Fayetteville Shale play of Arkansas, one operator is constructing a 500-acre-ft impoundment to store water withdrawals from the Little Red River obtained during periods of high flow (storm events or hydroelectric power generation releases from Greer's Ferry Dam upstream of the intake) when excess water is available[292] (one acre-foot is equivalent to the volume of water required to cover one acre with one foot of water). The project is limited to 1,550 acre-ft of water annually. As additional mitigation, the company has constructed extra pipelines and hydrants to provide portions of this rural area with water for fire protection. Also included is monitoring of in-stream water quality as well as game and non-game fish species in the reach of river surrounding the intake. This design provides a water recovery system similar in concept to what

***This project was developed with input from a local chapter of Trout Unlimited, an active conservation organization in the area, and represents an innovative environmental solution that serves both the community and the gas developer.***

some municipal water facilities use. It will minimize the impact on local water supplies because surface water withdrawals will be limited to times of excess flow in the Little Red River. This project was developed with input from a local chapter of Trout Unlimited, an active conservation organization in the area, and represents an innovative environmental solution that serves both the community and the gas developer.

Because the development of shale gas is new in some areas, these water needs may challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies can help operators and communities to coexist and effectively manage local water resources. Understanding local water needs can help operators develop a water storage or management plan that will meet with acceptance in neighboring communities. Although the water needed for drilling an individual well may represent a small volume over a large area, the withdrawals may have a cumulative impact to watersheds over the short term. This potential impact can be avoided by working with local water resource managers to develop a plan outlining when and where withdrawals will occur (i.e., avoiding headwaters, tributaries, small surface water bodies, or other sensitive sources).

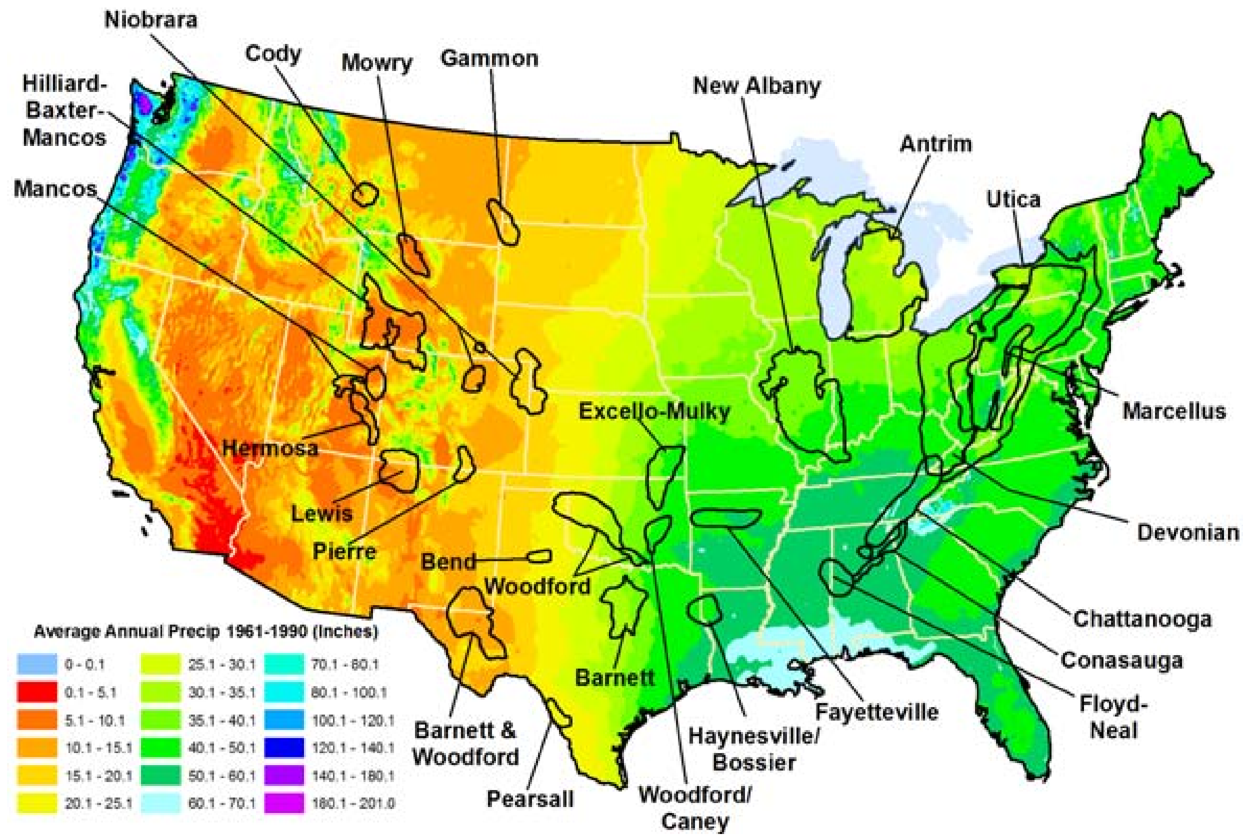
***One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs.***

In some basins, one key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region and even within a region such that developers will also need to understand local water laws[293] .

## Water Management

After a hydraulic fracture treatment, when the pumping pressure has been relieved from the well, the water-based fracturing fluid, mixed with any natural formation water present, begins to flow back through the well casing to the wellhead. This produced water may also contain dissolved constituents from the formation itself. The dissolved constituents are naturally occurring compounds and may vary from one shale play to the next or even by area within a shale play. Initial produced water can vary from fresh (<5,000 ppm Total Dissolved Solids (TDS)) to varying degrees of saline (5,000 ppm to 100,000 ppm TDS[294] or higher). The majority of fracturing fluid is recovered in a matter of several hours to a couple of weeks. In various basins and shale gas plays, the volume of produced water may account for less than 30% to more than 70% of the original fracture fluid volume[295]. In some cases, flow back of fracturing fluid in produced water can continue for several months after gas production has begun[296].

**EXHIBIT 38: ANNUAL RAINFALL MAP OF THE UNITED STATES**




*Source: NRCS*

A suite of circumstances explains the disposition of fracturing fluids that are not recovered through production. However, it is important to understand that unrecovered fluids, if any, will remain contained within the target formations. Some of these fluids will occupy macro-porosity (typically natural fracture porosity) in the shale formation and some will occupy the micro-pore space vacated by the gas that is produced. Also, some of the fracturing fluids remain stranded in fractures within the reservoir rock that heal after fracturing, thus preventing the fluids from flowing back to the well. Some of these stranded fluids may flow back to the well in very small volumes over an extended time span. The longer contact time these fluids have with the formation further alters the chemistry of these fluids through increased dissolution of formation minerals, making them similar to the natural formation water. For these reasons it is not possible to unequivocally state that 100% of the fracturing fluids have been recovered or to differentiate flow back water from natural formation water.

Natural formation water has been in contact with the reservoir formation for millions of years and thus contains minerals native to the reservoir rock. The salinity, TDS, and overall quality of formation water vary by geologic basin and specific rock strata. After initial production, produced water can vary from brackish (5,000 ppm to 35,000 ppm TDS), to saline (35,000 ppm to 50,000 ppm TDS), to supersaturated brine (50,000 ppm to >200,000 ppm TDS)[297], and some operators report TDS values greater than 400,000 ppm[298]. The variation in composition changes primarily with changes in the natural formation water chemistry.

States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. Exhibit 39 summarizes current produced water management practices for the various shale gas basins, and is compiled from data collected from producers and regulatory agencies in these basins.

Underground injection has traditionally been the primary disposal option for oil and gas produced water. In most settings, this may be the best option for shale gas produced water. This process uses salt water disposal wells to place the water thousands of feet underground in porous rock formations that are separated from treatable groundwater by multiple layers of impermeable rock thousands of feet thick. Underground injection of the produced water is not possible in every play as suitable injection zones may not be available. Similar to a producing reservoir, there must be a porous and permeable formation capable of receiving injected fluids nearby. If such is not locally available, it may be possible to transport the produced water to a more distant injection site. In well developed urban plays such as the Barnett Shale around the City of Fort Worth, pipelines have been constructed to transport produced water to injection well disposal sites. This minimizes trucking the water and the resultant traffic, exhaust emissions, and wear on local roads[299]. Injection disposal wells are permitted under the federal Safe Drinking Water Act (SDWA), Underground Injection Control (UIC) program (or in the case of state primacy, under equivalent state programs), a stringently permitted and monitored process with many environmental safeguards in place.

Treatment of produced water may be feasible through either self-contained systems at well sites or fields or municipal waste water treatment plants or commercial treatment facilities. The availability of municipal or commercial treatment plants may be limited to larger urban areas where treatment facilities with sufficient available capacity already exist. As in underground injection, transportation to treatment facilities may or may not be practical[300].

Re-use of fracturing fluids is being evaluated by service companies and operators to determine the degree of treatment and make-up water necessary for re-use[301]. The practical use of on-site, self-contained treatment facilities and the treatment methods employed will be dictated by flow rate and total water volumes to be treated, constituents and their concentrations requiring removal, treatment objectives and water reuse or discharge requirements. In some cases it would be more practical to treat the water to a quality that could be reused for a subsequent hydraulic fracturing job, or other industrial use, rather than treating to discharge to a surface water body or for use as drinking water. At the time this Primer was developed there were plans to construct commercial waste water treatment facilities specifically designed for the treatment of produced water associated with shale gas development in some locations around the country[302]. The completion and success of such plants no doubt will be closely tied to the successful expansion of production in the various shale gas plays.

### EXHIBIT 39: CURRENT PRODUCED WATER MANAGEMENT BY SHALE GAS BASIN.

| Shale Gas Basin | Water Management Technology | Availability | Comments |
|---|---|---|---|
| Barnett Shale | Class II injection wells[303] | Commercial and non-commercial | Disposal into the Barnett and underlying Ellenberger Group[304] |
| | Recycling[305] | On-site treatment and recycling | For reuse in subsequent fracturing jobs [306] |
| Fayetteville Shale | Class II injection wells[307] | Non-commercial | Water is transported to two injection wells owned and operated by a single producing company [308] |
| | Recycling | On-site recycling | For reuse in subsequent fracturing jobs[309] |
| Haynesville Shale | Class II injection wells | Commercial and non-commercial | |
| Marcellus Shale | Class II injection wells | Commercial and non-commercial | Limited use of Class II injection wells[310,311] |
| | Treatment and discharge | Municipal waste water treatment facilities, commercial facilities reportedly contemplated[312] | Primarily in Pennsylvania |
| | Recycling | On-site recycling | For reuse in subsequent fracturing jobs[313] |
| Woodford Shale | Class II injection wells | Commercial | Disposal into multiple confining formations[314] |
| | Land Application | | Permit required through the Oklahoma Corporation Commission[315] |
| | Recycling | Non-commercial | Water recycling and storage facilities at a central location[316] |
| Antrim Shale | Class II injection wells | Commercial and non-commercial | |
| New Albany Shale | Class II injection wells | Commercial and non-commercial | |

New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water. The treated water can be reused as fracturing make-up water, irrigation water, and in some cases even drinking water. Recycling or re-use of produced water can decrease water demands and provide additional water resources for drought-stricken or arid areas. This allows natural gas-associated produced water to be viewed as a potential resource in its own right[317,318]. In one case, Devon Energy Corporation (Devon) is currently using water distillation units at centralized locations within the Barnett Shale play to treat produced water from hydraulic fracture stimulations[319]. As of early 2008, Devon had hydraulically fractured 50 wells using recycled water. Devon reports that the program is still in its testing and development stages. With further development, such specialized treatment systems may prove beneficial, particularly in more mature plays such as the Barnett; however, their practicality may be limited in emerging shale gas plays. Current levels of interest in recycling and reuse are high, but new approaches and more efficient technologies are needed to make treatment and re-use a wide-spread reality.

While challenges still exist, progress is being made. New technologies and new variations on old technologies are being introduced on a regular basis, and some industry researchers are pursuing ways to reduce the amount of treatment needed. In early 2009, studies were underway to determine the minimum quality of water that could successfully be used in hydraulic fracturing. If hydraulic fracturing procedures or fluid additives can be developed that will allow use of water with a high TDS content, then more treatment options become viable and more water can be re-used. Treatment and re-use of produced water could reduce water withdrawal needs as well as the need for additional disposal options. This approach could also help to resolve many of the concerns associated with these withdrawals.

## Naturally Occurring Radioactive Material (NORM)

Some soils and geologic formations contain low levels of radioactive material. This naturally occurring radioactive material (NORM) emits low levels of radiation, to which everyone is exposed on a daily basis. Radiation from natural sources is also called background radiation. Other sources of background radiation include radiation from space and sources that occur naturally in the human body. This background radiation accounts for about 50% of the total exposure for Americans. Most of this background exposure is from radon gas encountered in homes (35% of the total exposure). The average person in the U.S. is exposed to about 360 millirem (mrem) of radiation from natural sources each year (a mrem, or one one-thousandth of a rem, is a measure of radiation exposure)[320]. The other 50% of exposures for Americans comes primarily from medical sources. Consumer products, industrial, and occupational sources contribute less than 3% of the total exposure[321].

In addition to the background radiation at the earth's surface, NORM can also be brought to the surface in the natural gas production process. When NORM is associated with oil and natural gas production, it begins as small amounts of uranium and thorium within the rock. These elements, along with some of their decay elements, notably $radium_{226}$ and $radium_{228}$[322], can be brought to the surface in drill cuttings and produced water. $Radon_{222}$, a gaseous decay element of radium, can come to the surface along with the shale gas.

When NORM is brought to the surface, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges[323]. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks[324].

The principal concern for NORM in the oil and gas industry is that, over time, it can become concentrated in field production equipment[325] and as sludge or sediment inside tanks and process vessels that have an extended history of contact with formation water[326]. Because the general public does not come into contact with oilfield equipment for extended periods, there is little exposure risk from oilfield NORM. Studies have shown that exposure risks for workers and the public are low for conventional oil and gas operations[327,328].

If measured NORM levels exceed state regulatory levels or OSHA exposure dose risks (29 CFR 1910.1096), the material is taken to licensed facilities for proper disposal. In all cases, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment for workers when radiation doses could exceed 5 mrem in one hour or 100 mrem in any five consecutive days. In addition to these federal worker protections, states have regulations that require operators to protect the safety and health of both workers and the public.

Currently there are no existing federal regulations that specifically address the handling and disposal of NORM wastes[d]. Instead, states producing oil and gas are responsible for promulgating and administering regulations to control the re-use and disposal of NORM-contaminated equipment, produced water, and oil-field wastes. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard oilfield waste. Conversely, if NORM concentrations are above regulatory limits, then the material must be disposed of at a licensed facility.

These regulations, standards, and practices ensure that oil and gas operations present negligible risk to the general public with respect to potential NORM exposure. They also present negligible risk to workers when proper controls are implemented[329].

## Air Quality

Many of today's air quality rules were primarily designed to regulate emissions from single sources with large volumes of emissions output such as refineries, chemical plants, iron and steel manufacturing facilities, and electrical power generating sites. However, smaller sources such as individual shale gas well sites are also subject to state and federal regulations. Shale gas exploration and production operations are similar to most other conventional and unconventional natural gas exploration and production operations in terms of their air emissions. However, varying gas composition and the fact that there is little or no associated oil production affects the nature of potential emissions.

[d] EPA does have drinking water standards for NORM.

### *Sources of Air Emissions*

The exploration and production of shale gas may include a variety of potential air emission sources that change depending on the phase of operation. In the early phases of operation, emissions may come from such sources as drilling rigs whose engines may be fueled by either diesel or natural gas and from fracturing operations where multiple diesel-powered pumps are often used to achieve the necessary pressure. Other sources may include the well completion process, which may involve the venting or flaring of some natural gas, and vehicular traffic with engine exhaust and dust from unpaved roads.

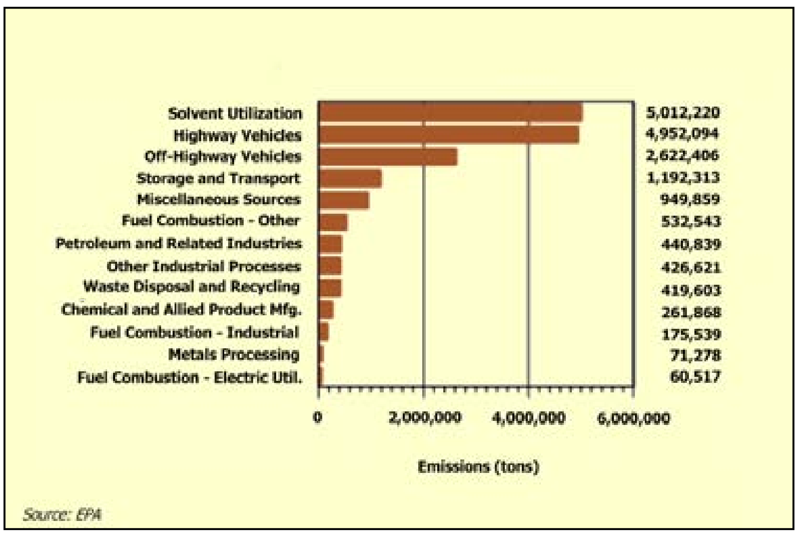
Once production has begun, emission sources may include compressors or pumps that may be needed to bring the produced gas up to the surface or up to pipeline pressure. Fugitive emissions such as leaks from pipe connections and associated equipment may also occur. Piping and pumping equipment may include pneumatic instrument systems, which, as part of their normal operations, release or bleed small amounts of natural gas into the atmosphere. Other sources of emissions in this phase of operations include flaring or blow down of gas in non-routine situations, dehydration units to remove water from the produced gas, and sulfur removal systems that may include flares and/or amine units.

### *Composition of Air Emissions*

EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities[330]. These emissions and their sources are discussed below.

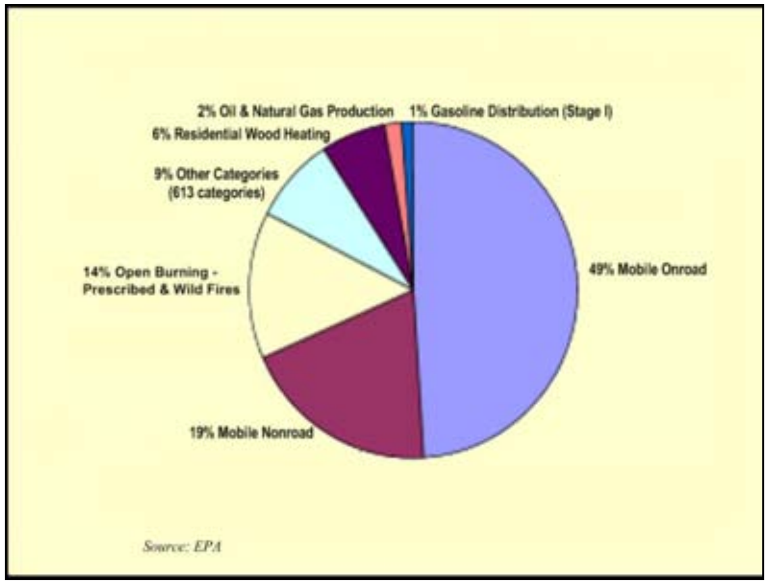
As in any construction or industrial activity, $NO_x$ are formed when fossil fuel is burned to provide power to machinery such as compressor engines and during flaring operations. In addition, VOCs may be emitted during the dehydration of natural gas. VOC emissions are typically lower in natural gas activities than those associated with oil production because gas production is essentially a closed process from well to pipeline with fewer opportunities for emissions. In addition, emissions of benzene, toluene, ethylbenzene, and xylenes are low simply because these compounds do not exist in significant quantities in the natural gas stream. The oil and gas industry in general is a lesser contributor to air emissions than numerous other common sources (see Exhibit 40[331]). Further, oil and natural gas production contributes only 2% of the total benzene emissions in the U.S.[332], and shale gas

**EXHIBIT 40: VOC EMISSIONS BY SOURCE CATEGORY**



represents a very small subset of this 2%.

**EXHIBIT 41: BENZENE EMISSIONS BY SOURCE - 1999**

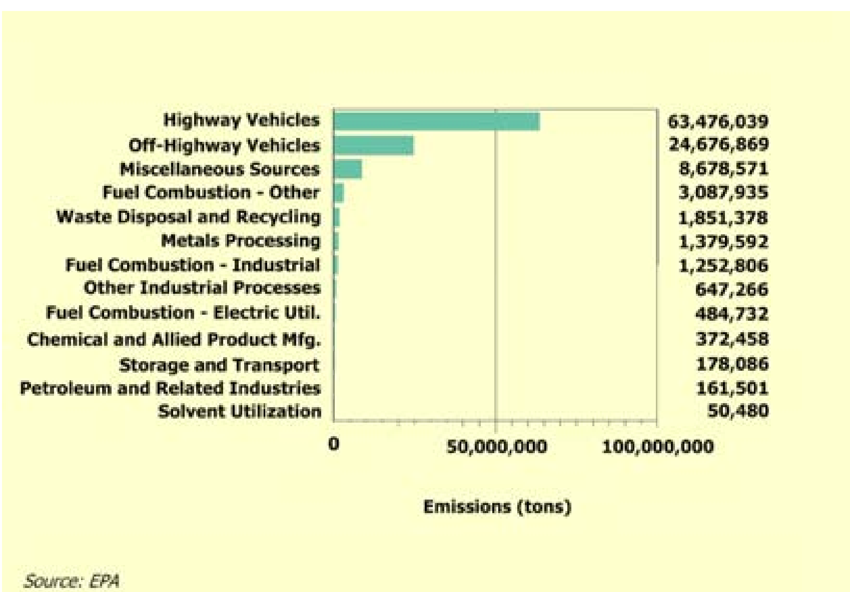



Particulate Matter (PM) may occur from dust or soil entering the air during pad construction, traffic on access roads, and diesel exhaust from vehicles and engines. In addition, CO may be emitted during flaring and from the incomplete combustion of carbon-based fuels used in engines. Flaring is seldom necessary with natural gas operations except during short periods of well testing, completions or workovers and non-routine situations such as a temporary pipeline closure. Exhibit 42[333] shows that CO emissions from the natural gas industry represent a very small part of the total[334].

$SO_2$ may form when fossil fuels containing sulfur are burned. Thus, $SO_2$ may be emitted from gasoline or diesel powered equipment used at a shale gas production site. However, emissions of $SO_2$ are typically very small for shale gas operations compared to coal or oil[335].

Ozone ($O_3$) itself is not released directly during natural gas development, but two of its main precursors, volatile organic compounds (VOCs) and $NO_x$, may combine with sunlight to form ground-level $O_3$ which can then be associated with exploration and production operations.

**EXHIBIT 42: CO EMISSIONS BY SOURCE CATEGORY**




Hydrogen sulfide ($H_2S$) emissions are not a concern in shale gas production as, based on discussions with operators from each of the major basins, the shale gas plays developed to date have not produced “sour” gas. If $H_2S$ is encountered as production continues, both states and operators are well equipped to implement appropriate safety measures. States have well-established public safety and worker protection requirements in place and operators have access to proven procedures for working with natural gas contaminated with $H_2S$.

The American Petroleum Institute (API) has a Recommended Practice (RP 49) for Drilling and Well Servicing Operations Involving $H_2S$[336]. Producers voluntarily follow this practice to minimize the release of and exposure to $H_2S$. In areas where concentrations of $H_2S$ may exceed 10 parts per million (ppm), producers implement an $H_2S$ contingency plan. The plan includes appropriate instruction in the use of hydrogen sulfide safety equipment to all personnel present at all hydrogen sulfide hazard areas, gas detection where hydrogen sulfide may exist, and appropriate respiratory protection for normal and emergency use.

Methane ($CH_4$) is the principal component of natural gas and a known GHG. Although the processing of natural gas is essentially confined from the well to sales, $CH_4$ may be released as a fugitive emission from gas processing equipment, especially equipment in high pressure service such as pneumatic controls. Producers have strong economic incentives to limit fugitive methane emissions to the greatest degree possible in order to maximize delivery of methane to market. Therefore, they rely on multiple BMPs (e.g., low-bleed gauges and valves, inspection and maintenance programs, infra-red (IR) cameras, etc.[337]) to reduce any potential energy loss.

Another potential source of emissions in natural gas fields are compressor engines. Many gas compressor engines are fueled by natural gas from the lease. Engine manufacturers are constantly improving their technology to reduce the amount of $NO_x$ emissions from their engines. One key has been the use of catalytic technologies to chemically convert $NO_x$ into inert compounds. The addition of catalytic emissions controls has successfully lowered engine emissions from 20 grams per horsepower hour down to 2 grams of $NO_x$ per horsepower hour or less. Also, the addition of air-fuel ratio controllers can be used to ensure the continuous low emissions performance of these engines. Recent EPA regulations require new engines to meet more stringent low $NO_x$ emissions standards regardless of engine size or fuel.

### *Technological Controls and Practices*

The best way to reduce air pollution is to prevent it from occurring in the first place. Pollution prevention can take many forms—upgrading equipment, improving operational practices, reducing waste through byproduct synergies, improving management practices, and installing emissions controls. Several government programs have been established that encompass avoidance, minimization, and mitigation strategies applicable to exploration and production activities. Some are mandatory regulations, as described in the Regulatory Framework section, while others are voluntary.

An example of the latter is the Natural Gas STAR program, a voluntary partnership between the EPA and the natural gas industry formed in 1995 to find cost-effective ways to ensure the natural gas industry is doing everything possible to prevent energy losses and to minimize GHG emissions[338]. The primary goals of the program are to promote technology transfer and implement cost-effective BMPs while reducing $CH_4$ emissions. The program provides information on many practices that not only reduce $CH_4$ emissions, but also works to retain greater volumes of natural gas for producers to sell.

Some of the most effective and economic technologies promoted by this program include:

1. Identification of high-bleed pneumatic devices (transducers, valves, controllers, etc.) and replacement with low-bleed ones to reduce fugitive product losses. Traditional pneumatic devices control processes by measuring changes in pressure, releasing small quantities of natural gas in the process. Newer devices are now available that perform the same functions while releasing much smaller amounts of gas.
2. Use of IR cameras in the field to visually identify any fugitive hydrocarbon leaks so that they may be rapidly repaired to reduce potential energy losses. These cameras are tuned to the wavelengths that are reflected by hydrocarbon gases, so that those normally-invisible gases actually become visible as "smoke" in the camera image, thus allowing companies to quickly detect and repair leaks.
3. Installation of flash tank separators in situations that require the use of dehydrators. This can recover 90 to 99% of the methane that would otherwise be flared or vented into the atmosphere[339].
4. Performance of green well completions and workovers. These shale gas operations typically use portable equipment to process and direct the produced natural gas into tanks or directly into the pipeline rather than the traditional practice of venting or flaring the gas. On average, green completions recover 53% of the natural gas that would otherwise have been flared or vented. That captured gas is now retained and sold to market[340].

Many other pollution reduction technologies and practices are described on EPA's GasSTAR web site. In 2004, the Methane to Markets Partnership was formed as a voluntary international program aimed at advancing the recovery and use of methane as a valuable clean energy source[341]. The program includes the oil and gas sector as a focus area along with coal mines, landfills, and the agricultural business. There are approximately 400 program members across the globe representing the oil and gas sector[342]. The collective results of these voluntary programs have been substantial. Total U.S. methane emissions in 2005 were over 11% lower than emissions in 1990, in spite of economic growth over that same time period[343]. EPA expects that these emissions will continue to fall in the future due to expanded industry participation and the ongoing commitment of the participating companies to identify and implement cost-effective technologies and practices.

Additional technologies and practices have been identified that may be used in some settings to reduce air emissions in shale gas fields. One such practice is the use of natural gas instead of diesel to fuel drilling rigs. Another emission-reducing practice applicable to some settings is the use of centralized processing facilities; this reduces vehicle trips, and therefore engine exhaust and dust emissions. Operators have also found that reducing glycol pump rates on dehydration units from their maximum setting to an optimized pump rate will minimize benzene, toluene, ethylbenzene, and total xylenes (BTEX) emissions. These units are often operated at a rate (based on at or near maximum throughput) that accommodates the initial, high rate of gas production from a field. However, as production rates decline, the dehydration units can be adjusted to conform to the lower gas throughput and reduce emissions. Other emission-reducing technologies include the installation of plunger lift systems into shale gas well heads to optimize gas production and reduce methane emissions associated with blowdown operations as well as the optimization of compressor and pump sizes to reduce the necessary horsepower and thus the subsequent exhaust emissions.

As with all operational practices, these BMPs must be applied on a case-by case basis. In some cases a given BMP may actually be counter-productive. In other cases, a particular BMP may create other environmental or operational problems that must be weighed against each other. While each BMP has certain benefits in certain situations, it cannot be universally applied or required.

State and federal requirements along with the technologies and practices developed by industry serve to limit air emissions from shale gas operations. As described earlier, state and federal requirements ensure that local conditions and other emission sources in the area are considered in issuing permits. In addition, advanced technologies and current practices serve to limit air emissions from modern shale gas development.

## Summary

The primary differences between modern shale gas development and conventional natural gas development are the extensive use of horizontal drilling and multi-stage hydraulic fracturing. Horizontal drilling allows an area to be developed with substantially fewer wells than would be needed if vertical wells were used. The overall process of horizontal drilling varies little from conventional drilling, with casing and cementing being used to protect fresh and treatable groundwater. The use of horizontal drilling has not introduced new environmental concerns. On the contrary, the reduced number of horizontal wells needed, coupled with multiple wells drilled from a single pad, has significantly reduced surface disturbances and the associated impacts to wildlife and impacts from dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to help reduce community impacts, impacts to sensitive environmental resources, and interference with existing businesses.

Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proven to be a safe and effective stimulation technique. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. The multi-stage hydraulic fracture operations used in horizontal wells may require 3 to 4 million gallons of water. Since it is a relatively new use in these areas, withdrawals for hydraulic fracturing must be balanced with existing water demands. Once the fracture treatment is completed, most of the fracture water comes back to the surface and must be managed in a way that conserves and protects water resources. While challenges continue to exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users can be met and that surface and ground water quality is protected.

An additional consideration in shale gas development is the potential for low levels of naturally occurring radioactive material (NORM) to be brought to the surface. While NORM may be encountered in shale gas operations, there is negligible exposure risk for the general public and there are well established regulatory programs that ensure public and worker safety

Although the use of natural gas offers a number of environmental benefits over other fossil energy sources, some air emissions commonly occur during exploration and production activities. EPA sets standards, monitors the ambient air quality across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

Taken together, state and federal requirements, along with the technologies and practices developed by industry, serve to protect human health and to help reduce environmental impacts from shale gas operations.

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# ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| API | American Petroleum Institute |
| bbls | barrels, petroleum (42 gallons) |
| bcf | billion cubic feet |
| BLM | Bureau of Land Management |
| BMP | Best Management Practices |
| Btu | British thermal units |
| CAA | Clean Air Act |
| CBNG | Coal Bed Natural Gas |
| CEQ | Council on Environmental Quality |
| CFR | Code of Federal Regulations |
| CERCLA | Comprehensive Environmental Response, Compensation, and Liability Act |
| $CH_4$ | Methane |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| CWA | Clean Water Act |
| DRBC | Delaware River Basin Commission |
| EIA | Energy Information Administration |
| ELG | Effluent Limitation Guidelines |
| EPA | Environmental Protection Agency |
| EPCRA | Emergency Planning and Community Right-to-Know Act |
| FR | Federal Register |
| ft | foot/feet |
| FWS | Fish and Wildlife Service |
| gal | gallon |
| GHG | Greenhouse Gases |
| GWPC | Ground Water Protection Council |
| $H_2S$ | Hydrogen Sulfide |
| HAP | Hazardous Air Pollutant |
| HCl | Hydrochloric acid |
| IOGCC | Interstate Oil and Gas Compact Commission |
| IR | infra-red |
| Mcf | thousand cubic feet |
| MMcf | million cubic feet |
| mrem | millirem |
| mrem/yr | millirem per year |
| MSDSs | Material Safety Data Sheets |
| NEPA | National Environmental Policy Act |
| NESHAPs | National Emission Standards for Hazardous Air Pollutants |
| NETL | National Energy Technology Laboratory |

| | |
|---|---|
| NORM | Naturally Occurring Radioactive Material |
| $NO_x$ | Nitrogen Oxides |
| NPDES | National Pollution Discharge Elimination System |
| NYDEC | New York State Department of Environmental Conservation |
| $O_3$ | Ozone |
| OPA | Oil Pollution Act |
| OSHA | Occupational Safety and Health Administration |
| PM | Particulate Matter |
| ppm | parts per million |
| RAPPS | Reasonable and Prudent Practices for Stabilization |
| RCRA | Resource Conservation and Recovery Act |
| RP | Recommended Practice |
| RQ | Reportable Quantity |
| SARA | Superfund Amendments and Reauthorization Act |
| SCF | standard cubic feet |
| SDWA | Safe Drinking Water Act |
| $SO_2$ | Sulfur Dioxide |
| SPCC | Spill Prevention, Control and Countermeasures |
| SRBC | Susquehanna River Basin Commission |
| STRONGER | State Review of Oil and Natural Gas Environmental Regulation, Inc. |
| SWDA | Solid Waste Disposal Act |
| tcf | trillion cubic feet |
| TDS | Total Dissolved Solids |
| tpy | tons per year |
| TRI | Toxics Release Inventory |
| UIC | Underground Injection Control |
| U.S. | United States |
| U.S.C. | United States Code |
| USDW | Underground Source of Drinking Water |
| USGS | United States Geological Survey |
| VOC | Volatile Organic Compound |
| WQA | Water Quality Act |
| yr | year |

# DEFINITIONS

**AIR QUALITY.** A measure of the amount of pollutants emitted into the atmosphere and the dispersion potential of an area to dilute those pollutants.

**AQUIFER.** A body of rock that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

**BASIN.** A closed geologic structure in which the beds dip toward a central location; the youngest rocks are at the center of a basin and are partly or completely ringed by progressively older rocks.

**BIOGENIC GAS.** Natural gas produced by living organisms or biological processes.

**CASING.** Steel piping positioned in a wellbore and cemented in place to prevent the soil or rock from caving in. It also serves to isolate fluids, such as water, gas, and oil, from the surrounding geologic formations.

**COAL BED METHANE/NATURAL GAS (CBM/CBNG).** A clean-burning natural gas found deep inside and around coal seams. The gas has an affinity to coal and is held in place by pressure from groundwater. CBNG is produced by drilling a wellbore into the coal seam(s), pumping out large volumes of groundwater to reduce the hydrostatic pressure, allowing the gas to dissociate from the coal and flow to the surface.

**COMPLETION**. The activities and methods to prepare a well for production and following drilling. Includes installation of equipment for production from a gas well.

**CORRIDOR.** A strip of land through which one or more existing or potential utilities may be co-located.

**DISPOSAL WELL.** A well which injects produced water into an underground formation for disposal.

**DIRECTIONAL DRILLING.** The technique of drilling at an angle from a surface location to reach a target formation not located directly underneath the well pad.

**DRILL RIG.** The mast, draw works, and attendant surface equipment of a drilling or workover unit.

**EMISSION.** Air pollution discharge into the atmosphere, usually specified by mass per unit time.

**ENDANGERED SPECIES.** Those species of plants or animals classified by the Secretary of the Interior or the Secretary of Commerce as endangered pursuant to Section 4 of the Endangered Species Act of 1973, as amended. See also **Threatened and Endangered Species**.

**EXPLORATION.** The process of identifying a potential subsurface geologic target formation and the active drilling of a borehole designed to assess the natural gas or oil.

**FLOW LINE.** A small diameter pipeline that generally connects a well to the initial processing facility.

**FORMATION (GEOLOGIC).** A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

**FRACTURING FLUIDS.** A mixture of water and additives used to hydraulically induce cracks in the target formation.

**GROUND WATER.** Subsurface water that is in the zone of saturation; source of water for wells, seepage, and springs. The top surface of the groundwater is the "water table."

**HABITAT.** The area in which a particular species lives. In wildlife management, the major elements of a habitat are considered to be food, water, cover, breeding space, and living space.

**HORIZONTAL DRILLING.** A drilling procedure in which the wellbore is drilled vertically to a kick-off depth above the target formation and then angled through a wide 90 degree arc such that the producing portion of the well extends horizontally through the target formation.

**HYDRAULIC FRACTURING.** Injecting fracturing fluids into the target formation at a force exceeding the parting pressure of the rock thus inducing a network of fractures through which oil or natural gas can flow to the wellbore.

**HYDROSTATIC PRESSURE.** The pressure exerted by a fluid at rest due to its inherent physical properties and the amount of pressure being exerted on it from outside forces.

**INJECTION WELL.** A well used to inject fluids into an underground formation either for enhanced recovery or disposal.

**LEASE**. A legal document that conveys to an operator the right to drill for oil and gas. Also, the tract of land, on which a lease has been obtained, where producing wells and production equipment are located.

**NORM (Naturally Occurring Radioactive Material).** Low-level, radioactive material that naturally exists in native materials.

**ORIGINAL GAS- IN- PLACE T**he entire volume of gas contained in the reservoir, regardless of the ability to produce it.

**PARTICULATE MATTER (PM).** A small particle of solid or liquid matter (e.g., soot, dust, and mist). $PM_{10}$ refers to particulate matter having a size diameter of less than 10 millionths of a meter (micro-meter) and $PM_{2.5}$ being less than 2.5 micro-meters in diameter.

**PERMEABILITY.** A rock's capacity to transmit a fluid; dependent upon the size and shape of pores and interconnecting pore throats. A rock may have significant porosity (many microscopic pores) but have low permeability if the pores are not interconnected. Permeability may also exist or be enhanced through fractures that connect the pores.

**PRIMACY.** A right that can be granted to state by the federal government that allows state agencies to implement programs with federal oversight. Usually, the states develop their own set of regulations. By statute, states may adopt their own standards, however, these must be at least as protective as the federal standards they replace, and may be even more protective in order to address local conditions. Once these state programs are approved by the relevant federal agency (usually the EPA), the state then has primacy jurisdiction.

**PRODUCED WATER.** Water produced from oil and gas wells.

**PROPPING AGENTS/PROPPANT.** Silica sand or other particles pumped into a formation during a hydraulic fracturing operation to keep fractures open and maintain permeability.

**PROVED RESERVES** That portion of recoverable resources that is demonstrated by actual production or conclusive formation tests to be technically, economically, and legally producible under existing economic and operating conditions.

**RECLAMATION.** Rehabilitation of a disturbed area to make it acceptable for designated uses. This normally involves regrading, replacement of topsoil, re-vegetation, and other work necessary to restore it.

**SET-BACK.** The distance that must be maintained between a well or other specified equipment and any protected structure or feature.

**SHALE GAS.** Natural gas produced from low permeability shale formations.

**SLICKWATER.** A water based fluid mixed with friction reducing agents, commonly potassium chloride.

**SOLID WASTE.** Any solid, semi-solid, liquid, or contained gaseous material that is intended for disposal.

**SPLIT ESTATE.** Condition that exists when the surface rights and mineral rights of a given area are owned by different persons or entities; also referred to as "severed estate".

**STIMULATION.** Any of several processes used to enhance near wellbore permeability and reservoir permeability.

**STIPULATION.** A condition or requirement attached to a lease or contract, usually dealing with protection of the environment, or recovery of a mineral.

**SULFUR DIOXIDE ($SO_2$).** A colorless gas formed when sulfur oxidizes, often as a result of burning trace amounts of sulfur in fossil fuels.

**TECHNICALLY RECOVERABLE RESOURCES** The total amount of resource, discovered and undiscovered, that is thought to be recoverable with available technology, regardless of economics.

**THERMOGENIC GAS.** Natural gas that is formed by the combined forces of high pressure and temperature (both from deep burial within the earth's crust), resulting in the natural cracking of the organic matter in the source rock matrix.

**THREATENED AND ENDANGERED SPECIES.** Plant or animal species that have been designated as being in danger of extinction. See also **Endangered Species.**

**TIGHT GAS.** Natural gas trapped in a hardrock, sandstone or limestone formation that is relatively impermeable.

**TOTAL DISSOLVED SOLIDS (TDS).** The dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in parts per million.

**UNDERGROUND INJECTION CONTROL PROGRAM (UIC).** A program administered by the Environmental Protection Agency, primacy state, or Indian tribe under the Safe Drinking Water Act to ensure that subsurface emplacement of fluids does not endanger underground sources of drinking water.

**UNDERGROUND SOURCE OF DRINKING WATER (USDW).** 40 CFR Section 144.3 An aquifer or its portion:

(a) (1) Which supplies any public water system; or

(2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer.

**WATER QUALITY.** The chemical, physical, and biological characteristics of water with respect to its suitability for a particular use.

**WATERSHED.** All lands which are enclosed by a continuous hydrologic drainage divide and lay upslope from a specified point on a stream.

**WELL COMPLETION**. See **Completion**.

**WORKOVER.** To perform one or more remedial operations on a producing or injection well to increase production. Deepening, plugging back, pulling, and resetting the liner are examples of workover operations.

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April 2009

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# Shale Gas: *Applying Technology to Solve America's Energy Challenges*

**The United States enjoys a rich complement of natural resources, including substantial quantities of fossil fuels—crude oil, coal, and natural gas. These energy sources have helped to fuel our Nation's growth and development for the past two hundred years.**

The presence of natural gas—primarily methane—in the shale layers of sedimentary rock formations that were deposited in ancient seas has been recognized for many years. The difficulty in extracting the gas from these rocks has meant that oil and gas companies have historically chosen to tap the more permeable sandstone or limestone layers which give up their gas more easily.

**Shale gas well on a Pennsylvania farm. (Photos courtesy of Range Resources)**

But American ingenuity and steady research have led to new ways to extract gas from shales, making hundreds of trillions of cubic feet of gas technically recoverable where they once were not.

New technologies are also being applied to make certain that the process of drilling for this valuable resource minimizes environmental impacts.

U.S. DEPARTMENT OF ENERGY | NETL

Barnett shale well at urban location (Courtesy of Chesapeake Energy)

Fayetteville shale well (Courtesy of Southwestern Energy)

This resource's availability to the American people could not have come at a better time. The calls for reducing our reliance on foreign energy supplies, for reducing our contribution of carbon dioxide to the atmosphere, and for increasing economic growth and wealth creation, can all be met, at least in part, by the development of shale gas. The U.S. Department of Energy (DOE), through the National Energy Technology Laboratory (NETL), has played a historic role in helping to advance the technology that is making shale gas production possible.


This map, available from the U.S. Energy Information Administration (EIA) at http://www.eia.doe.gov, shows the location and extent of the major shale plays (e.g., Marcellus shale) and the sedimentary basins (regions with thick layers of sedimentary rock containing fossil fuels) where these shale plays are found.

# The Resource

## Where shale gas comes from

About 360–415 million years ago, during the Devonian Period of Earth's history, the thick shales from which we are now producing natural gas were being deposited as fine silt and clay particles at the bottom of relatively enclosed bodies of water. At roughly the same time, primitive plants were forming forests on land and the first amphibians were making an appearance. Some of the methane that formed from the organic matter buried with the sediments escaped into sandy rock layers adjacent to the shales, forming conventional accumulations of natural gas which were relatively easy to extract. But some of it remained locked in the tight, low permeability shale layers.

This map of what geologists believe the land looked like 385 million years ago (during the Middle Devonian period) shows the outlines of today's states, and the bodies of water that created the Michigan, Appalachian, and Illinois basins can be seen. (Courtesy Prof. Ron Blakey, Northern Arizona University)

## History of development

The shale gas timeline includes a number of important milestones:

Photo credit Drake Well Museum

**1821** – First U.S. commercial natural gas well in Fredonia, New York, produces gas from shale.

**1859** – Edwin Drake demonstrates that oil can be produced in large volumes, launching the U.S. oil industry.

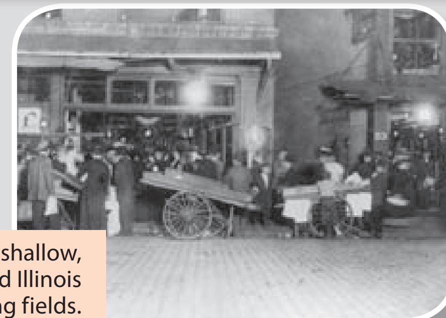


Photo credit Library of Congress

**1860s to 1920s** – Natural gas, including gas produced from shallow, low pressure, fractured shales in the Appalachian and Illinois basins, is limited to use in cities close to producing fields.

**1930s** – Technology developed to lay large diameter pipelines makes transmission of large volumes of gas from midcontinent and southeastern oil fields to northeastern cities possible; the natural gas industry grows exponentially.

Photo credit Ohio Historical Society

Photo credit Pennwell

**Late 1940s** – Hydraulic fracturing first used to stimulate oil and gas wells. The first hydraulic fracturing treatment (not shown here ) was pumped in 1947 on a gas well operated by Pan American Petroleum Corporation in Grant County, Kansas.

**Early 1970s** – Development of downhole motors, a key component of directional drilling technology, accelerates. Directional drilling capabilities continue to advance for the next three decades.

**Late 1970s and early 1980s** – Fear that U.S. natural gas resources are dwindling prompts federally sponsored research to develop methods to estimate the volume of gas in "unconventional natural gas reservoirs" such as gas shales, tight sandstones and coal seams, and to improve ways to extract the gas from such rocks. Deeper buried shales, such as the Barnett in Texas and Marcellus in Pennsylvania, are known but believed to have essentially zero permeability and thus are not considered economic.

**1980s to early 1990s** – Mitchell Energy combines larger fracture designs, rigorous reservoir characterization, horizontal drilling, and lower cost approaches to hydraulic fracturing to make the Barnett Shale economic.

**2003 to 2004** – Gas production from the Barnett Shale play overtakes the level of shallow shale gas production from historic shale plays like the Appalachian Ohio Shale and Michigan Basin Antrim plays. About 2 billion cubic feet (Bcf) of gas per day are produced from U.S. shales.

Photo credit Pennwell

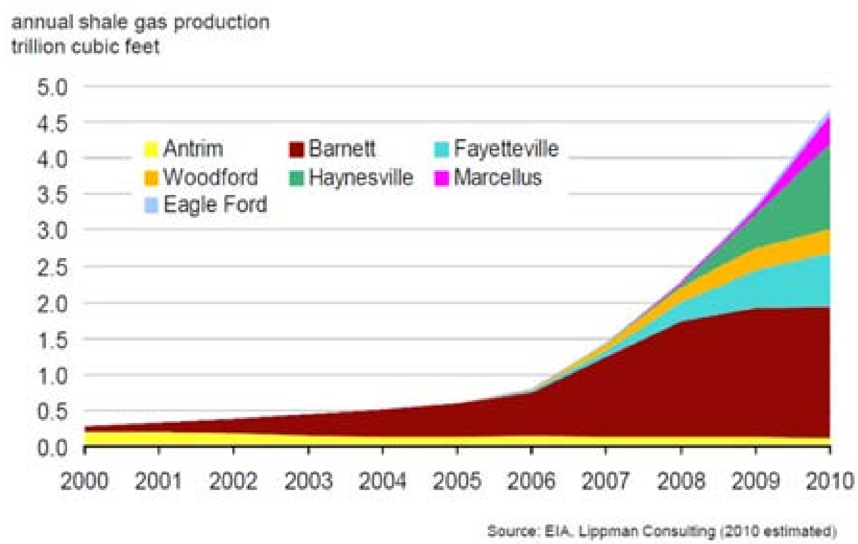
**2005 to 2010** – Gas production from Barnett Shale grows to about 5 Bcf per day. Development of other major shale plays begins in other major basins.

**2010** – The Marcellus shale underlies a significant portion of the mid-Atlantic/NE region—close to East Coast metropolitan natural gas demand centers—and is thought to contain nearly half of the technically recoverable shale gas resource.

## Production trend

Shale gas production continues to increase. In 2009 it amounted to more than 8 Bcf per day, or about 14 % of the total volume of dry natural gas produced in the United States and about 12% of the natural gas consumed in the United States. Production from the Barnett Shale has leveled off, but volumes of gas from the Marcellus, Haynesville, Fayetteville and Woodford shales are growing as more wells are drilled in these plays and as other emerging plays are developed. The EIA projects that the shale gas share of U.S. natural gas production will continue to grow, reaching 45% of the total volume of gas produced in the United States by 2035.

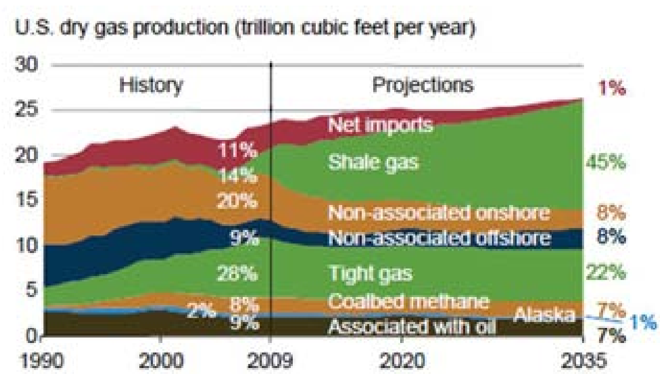
Core from organic Devonian shale formation




## What it means for us

The EIA projects that there are 827 trillion cubic feet (Tcf) of natural gas that are recoverable from U.S. shales using currently available technology. The United States currently consumes about 23 Tcf per year, of which we produce about 20 Tcf and import the rest, so the shale gas resource alone  represents about 36 years of current consumption. One Tcf of natural gas is enough to heat 15 million homes for 1 year, generate 100 billion kilowatt-hours of electricity, or fuel 12 million natural-gas-fired vehicles for 1 year.

Developing domestic natural gas resources means additional jobs (economic growth) when wells are drilled, pipelines are constructed, and production facilities are built and operated. In addition, higher volumes of available domestic natural gas mean lower fuel or feedstock prices for industries that use natural gas to process or manufacture products. This means fewer jobs lost to lower-cost overseas competitors, as well as lower prices for consumers.




The EIA's Annual Energy Outlook for 2011 shows the contribution of shale gas to U.S. natural gas production reaching 45% by 2035.

Shale gas production also means increased tax and royalty receipts for state and federal government, and increased economic activity in producing areas from royalty and bonus payments to landowners.  This influx of revenue can be used to enhance public services.

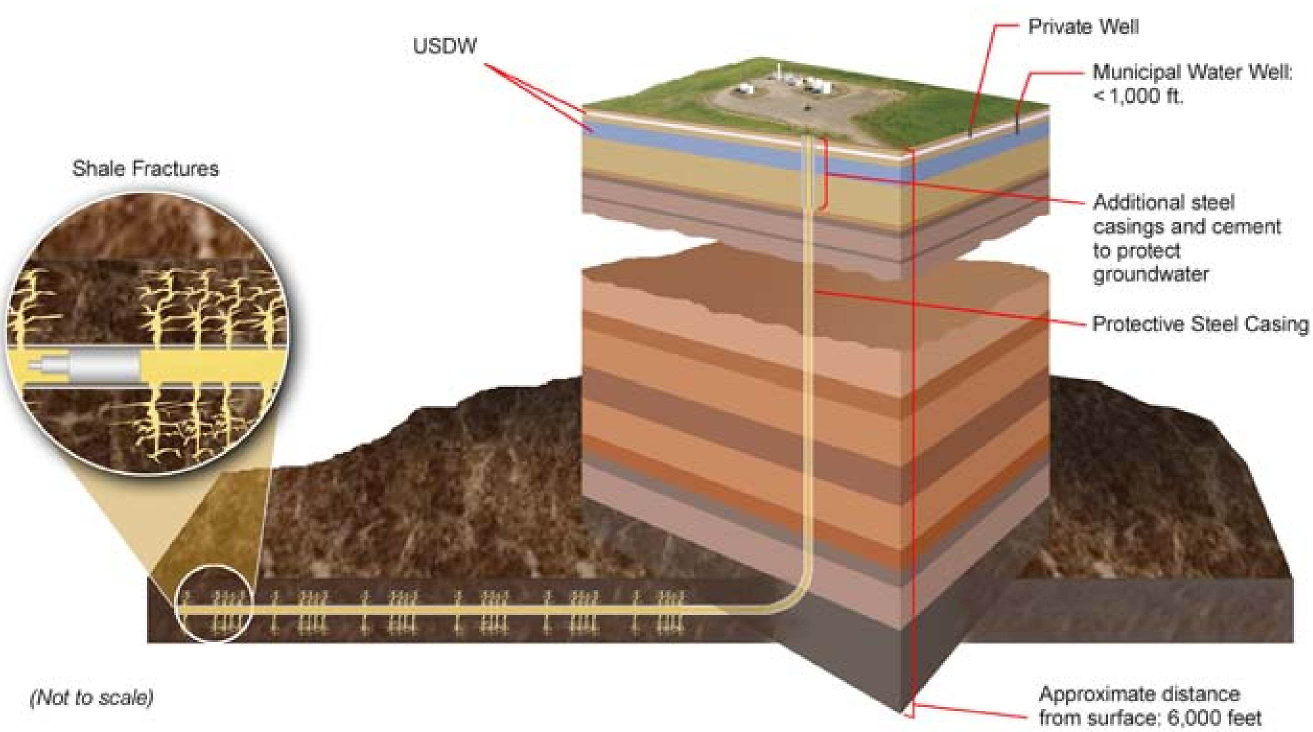
# The Technology

## How it works

Wells are drilled vertically to intersect the shale formations at depths that typically range from 6,000 to more than 14,000 feet. Above the target depth the well is deviated to achieve a horizontal wellbore within the shale formation, which can be hundreds of feet thick. Wells may be oriented in a direction that is designed to maximize the number of natural fractures present in the shale intersected. These natural fractures can provide pathways for the gas that is present in the rock matrix to flow into the wellbore. Horizontal wellbore sections of 5,000 feet or more may be drilled and lined with metal casing before the well is ready to be hydraulically fractured.

## Hydraulic fracturing

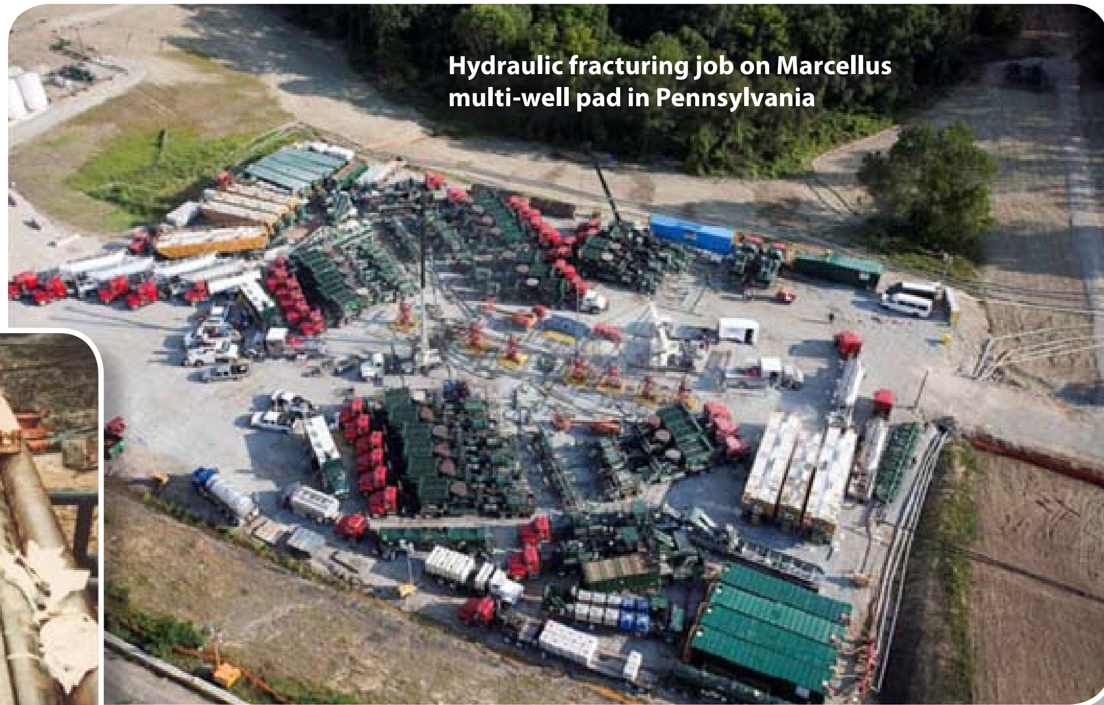
Beginning at the toe of the long horizontal section of the well, segments of the wellbore are isolated, the casing is perforated, and water is pumped under high pressure (thousands of pounds per square inch) through the perforations, cracking the shale and creating one or more fractures that extend out into the surrounding rock. These fractures continue to propagate, for hundreds of feet or more, until the pumping ceases. Sand carried along in the water props open the fracture after pumping stops and the pressure is relieved. The propped fracture is only a fraction of an inch wide, held open by these sand grains. Each of these fracturing stages can involve as much as 10,000 barrels (420,000 gallons) of water with a pound per gallon of sand. Shale wells have as many as 25 fracture stages, meaning that more than 10 million gallons of water may be pumped into a single well during the completion process. A portion of this water is flowed back immediately when the fracturing process is completed, and is reused. Additional volumes return over time as the well is produced.




Steel casing lines the well and is cemented in place to prevent any communication up the wellbore as the fracturing job is pumped or the well is produced. Shallow formations holding fresh water that may be useful for farming or public consumption are separated from the fractured shale by thousands of feet of rock.

## NETL's early contributions

In the 1970s, fears of dwindling domestic natural gas supplies spurred DOE researchers to examine alternative sources of natural gas in unconventional reservoirs such as shales, coal seams, and tight sandstones. NETL helped to advance foam fracturing technology, oriented coring and fractographic analysis, and large-volume hydraulic fracturing. In 1975, a DOE-industry joint venture drilled the first Appalachian Basin directional wells to tap shale gas, and shortly thereafter completed the first horizontal shale well to employ seven individual hydraulically fractured intervals. DOE integrated basic core and geologic data from 35 research wells to prepare the first, publicly available estimates of technically recoverable gas for gas shales in West Virginia, Ohio, and Kentucky.

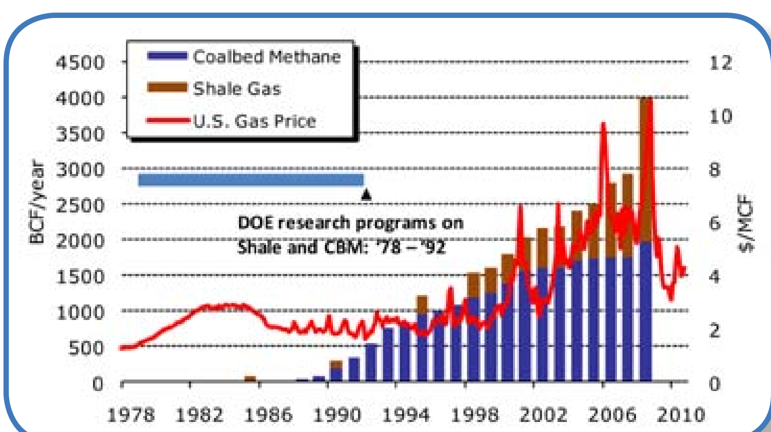



DOE researchers gathering data from one of a series of cored shale wells in the Appalachian Basin in the early 1980s.

DOE's important contributions to shale gas development have been recognized by many. According to Penn State University's Dr. Terry Engelder, a recognized expert on the Marcellus Shale, DOE's Eastern Gas Shales Research Program "helped expand the limits of gas shale production and increased understanding of production mechanisms. It is one of the great examples of value-added work led by the DOE." In his recent paper summarizing thirty years of gas shale fracturing, George E. King, Global Technology Consultant for Apache Corporation, states that "Technology developments in the North American Devonian shale during the late 1970s and proceeding into the 90s, chiefly from a loose alliance of the U.S. Department of Energy, the Gas Research Institute and numerous operators, combined to collectively produce several breakthroughs … horizontal wells, multi-stage fracturing and slick water fracturing." Fred Julander of Julander Energy, a 36-year independent producer and a member of the National Petroleum Council, has stated that "The Department of Energy was there with research funding when no one else was interested and today we are all reaping the benefits. Early DOE R&D in tight gas sands, gas shales, and coalbed methane helped to catalyze the development of technologies that we are applying today."

For example, EQT, an independent producer in Pittsburgh, PA, has been developing the Huron Shale in Eastern KY using air drilling technology that relies on electromagnetic telemetry (EMT) to directionally drill horizontal wellbores. EQT reports that it is currently producing more than 100 million cubic feet per day (MMcfd) from its Huron wells and believes the resource potential could be as much as 10 Tcf of gas equivalent. The EMT technology now offered by Sperry Drilling (a Halliburton service line) has its roots in DOE research from the 1980s and 90s. "In the early 1980s, the industry as a whole did not have a clear vision for producing gas from shales and benefited from DOE involvement and funding of EMT technology… there is a clear line of sight between the initial research project and the commercial EMT service available today," states Dan Gleitman, Sr. Director – Intellectual Asset Management, Halliburton.

While decades of technological enhancements stand behind the suite of tools and methodologies that make shale gas production possible, publicly funded R&D has played an important role. NETL continues to manage a suite of research projects focused on increasing the supply of domestic natural gas to the consumer, in an environmentally sustainable and increasingly safe manner.



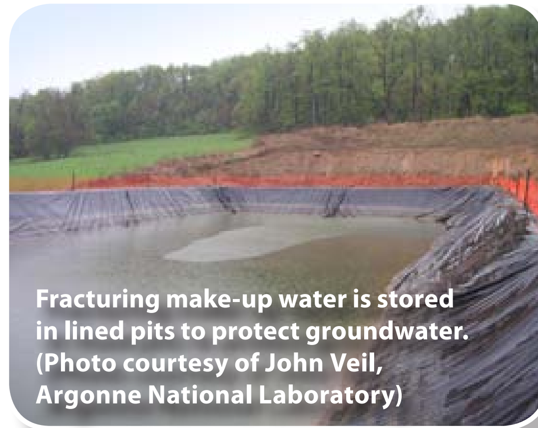

DOE research during the 1980s played a role in the growth of unconventional gas production that is now helping to reduce the price of natural gas to consumers

# What's Next

## What DOE is doing now

Currently, NETL is actively involved in advancing technologies that can help producers develop shale gas resources in the most environmentally responsible manner.  Research is under way to find improved ways to treat fracture flowback water so that it can be reused or easily disposed of and to reduce the "footprint" of shale gas operations so that there is less disruption of the surface during drilling and completion operations.

DOE is refocusing the work done under Section 999 (Subtitle J) of the Energy Policy Act of 2005 on safety, environmental sustainability, and quantifying the risks of exploration and production activity.


**Fracturing make-up water is stored in lined pits to protect groundwater. (Photo courtesy of John Veil, Argonne National Laboratory)**


**Fracturing trucks on location at a Pennsylvania Marcellus location. (Photo courtesy of John Veil, Argonne National Laboratory)**

DOE is working closely with the U.S. Environmental Protection Agency (EPA) as it carries out an exhaustive study to quantify the potential risk of hydraulic fracturing to underground sources of drinking water. NETL is also collaborating with the Department of Interior to enhance understanding of these risks.

Recent years have witnessed a number of initiatives to address the challenges of producing shale gas, sponsored by states, environmental groups, industry advocacy groups, and research organizations.  DOE is exploring creation of a Shale Gas Initiative, in cooperation with public, private and non-governmental stakeholders, to build on these efforts and identify "best practices" that could be used by both operators and regulatory agencies to raise the bar on safety and environmental sustainability during shale gas development.

The U.S. Department of State has launched a U.S.-China Shale Gas Resource Initiative to help reduce greenhouse gas emissions, promote energy security and create commercial opportunities for U.S. companies. To date, the effort has engaged hundreds of Chinese technologists, facilitated a Chinese delegation's visit to a U.S. shale gas development operation, and created interest in American unconventional gas technologies through forums and workshops.


**Well sites require temporary disturbance of the landscape while drilling is underway. (Marcellus well site photo courtesy of Range Resources)**

DOE has worked with states through the Ground Water Protection Council (GWPC) to develop and maintain the Risk-Based Data Management System (RBDMS). Nationwide, 20 states and one Indian Nation now use the RBDMS to help operators comply with regulations. DOE has recently enhanced the RBDMS to track and record data related to hydraulic fracturing treatments. DOE has also funded in part, a Hydraulic Fracturing Chemical Registry to be hosted by the GWPC and  Interstate Oil and Gas Compact Commission (IOGCC). This website will be a means for the industry to voluntarily supply hydraulic fracturing chemical data in a consistent and centralized location.

In 2009, DOE teamed with IOGCC to form a Shale Gas Directors Task Force to serve as a forum for states to share insights on issues and innovations related to shale gas development at the local, state and federal levels. More information is available at www.iogcc.org and http://groundwork.iogcc.org.

While it will be impossible to extract shale gas without some temporary disruption to the rural landscape, new and existing technologies can be employed to limit this disruption, to mitigate any surface impacts, and to minimize impacts to other natural resources in the process.

## *Where to find out more*

You can find out more about shale gas from these resources:

- **NETL website –** The National Energy Technology Laboratory has a complete list of research projects, with details about objectives, accomplishments, expected benefits and results, at http://www.netl.doe.gov/.

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- **DOE website –** The Department of Energy has information available on Department objectives and accomplishments related to natural gas at http://energy.gov/energysources/naturalgas.htm.

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- **Marcellus Shale Coalition website –** This website has general information provided by an organization "committed to the responsible development of natural gas from the Marcellus Shale geological formation and the enhancement of the region's economy that can be realized by this clean-burning energy source" at http://marcelluscoalition.org/home/.

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- **Groundwork –** The IOGCC website focuses on shale gas regulatory information at http://groundwork.iogcc.org.

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- **Publications –** A number of publications have been produced by NETL and others that help to explain shale gas and the technologies involved. These include:
  - "Modern Shale Gas Development in the United States – A Primer," available for download at http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf
  - NETL's "E & P Focus Newsletter" provides updates on various shale gas research projects, available for download at http://www.netl.doe.gov/technologies/oil-gas/ReferenceShelf/epfocus.html
  - "An Emerging Giant: Prospects and Economic Impacts of Developing the Marcellus Shale Natural Gas Play," available for download at http://www.alleghenyconference.org/PDFs/PELMisc/PSUStudyMarcellusShale072409.pdf
  - "The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update," available for download at http://marcelluscoalition.org/wp-content/uploads/2010/05/PA-Marcellus-Updated-Economic-Impacts-5.24.10.3.pdf
  - "Developing the Marcellus Shale," available for download at http://www.pecpa.org/sites/pecpa.org/files/downloads/Developing_the_Marcellus_Shale_0.pdf
  - "Water Resources and Natural Gas Production from the Marcellus Shale," available for download at http://pubs.usgs.gov/fs/2009/3032/
  - "Homegrown Energy: The Facts About Natural Gas Exploration of the Marcellus Shale," available for download at http://www.marcellusfacts.com/pdf/homegrownenergy.pdf
  - "The Future of Natural Gas: An Interdisciplinary MIT Study," available for download at http://web.mit.edu/mitei/research/studies/naturalgas.html

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**FW: FW: Goodrich/Chesapeake Haynesville Production Forecast????????** Inbox x

[redacted] show details 11/7/09 Reply

After reading your reply and your frustration as to how anyone can interpret the results to date and come up with the story these companies put out……..read my email below. I am only familiar personally with the Haynesville Shale in North Louisiana. I have continued to keep these data bases up to date. It is becoming apparent to me that the reason the Petrohawk wells are better is they have "the sweet spot". Other engineers/geologist that are more familiar with the entire Haynesville Shale play are telling me, and I am beginning to believe them, that the only place where the Haynesville Shale play is going to ever be economical is the "sweet spot". No one is sure of the exact extent but it is centered around the Elm Grove, Caspiana and Holly ridge areas of southern Caddo and Bossier and Northern DeSoto. The jury is still out on the more eastern and southeastern areas. What I hear over and over again and have seen with my limited data research the East Texas stuff will never be economical given "normal" economic conditions.

Back to your point……………there is now plenty of production data available from the states to show that these wells are no where near what these guys are touting. I have discussed this numerous times with analysts that are friends of mine – they agree with me and then just shrug their shoulders. I do not know of a single individual in the oil business that is investing their money drilling in the Haynesville Shale play. Every single one that I know, that has the ability to analyze the play, has chosen to sit it out an further if they were lucky enough, like I was, to own minerals sell. EVERY SINGLE ONE.

So why is it that all of us that are investing our own money are choosing not to invest………….are we all wrong? The education that I got at Enron with these type people (I know one of the HWK board members he even went so far as to email me months ago to try and change my mind, it was unbelievable, out of the blue he starts sending me emails) has given me more confidence to go with what I believe once I have the data needed to make the proper decision. I now have the proper data needed to evaluate the Haynesville Shale and I will be sitting it out for the foreseeable future.

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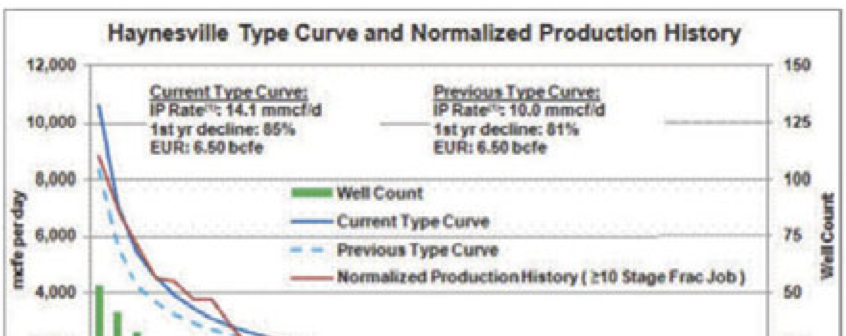
**From:** [redacted]@[redacted]oil.com]
**Sent:** Tuesday, August 18, 2009 4:37 PM
**To:** [redacted]
**Subject:** RE: FW: Goodrich/Chesapeake Haynesville Production Forecast????????

I guess I just do not understand. Chesapeake puts out the chart below in their latest operational update. They have upped their IP Rate on their current Type curve by 4 Mmcf/d and yet their history shows an IP Rate closer to their original type curve. Their very best wells only average a first month production rate of 8,684 mcf/d………very close to their original type curve. Their new type curve now shows first month average rate of over 10,000 Mmcf/d. ??????????????????????????????????

They show a normalized production history on their graph. It does not seem to make sense………it is a straight line decline for the 1st 4 mths. This does not seem to be based on any real averaged history or the lines would not be so straight for extended periods of time. None the less, their own curve shows the normalized production history falling below their present type curve. I guess maybe they are trying to explain this some way that I do not understand. ????????????????? Their normalized curve they present just does not seem to indicate the big hyperbolic curve they are projecting. What am I missing?



# FW: Goodrich/Chesapeake Haynesville Production Forecast???????? Inbox X

[redacted]

show details 7/27/09 Reply

Thought I would forward you my latest.

Any guesses as to the answer to my question below - when will Chesapeake et al have to start admitting these wells are not what they were projecting?

---

**From:** [redacted]@[redacted]oil.com]
**Sent:** Monday, July 27, 2009 3:35 PM
**To:** [redacted]
**Cc:** [redacted]
**Subject:** Goodrich/Chesapeake Haynesville Production Forecast????????

I went to Goodrich's website to look at their Haynesville discussion sections. In there was their production forecast for High (8.5 Bcf), Base (6.5 Bcf) and Low (4.5 Bcf) Type cases. I believe from the discussion that they relied pretty heavily (if not entirely) on Chesapeake for these forecast.

I took the three type cases and overlaid them on my most recent actual normalized Chesapeake Haynesville production for the 25 wells that now have publicly reported data (see attached). Note that 19 of the 25 wells now have at least 6 months production history.............in other words a pretty good size data set with a significant history is now available to be analyzed.

It looks pretty clear to me that the wells are not performing anything like Goodrich/Chesapeake are projecting (note this data that I picked up that Goodrich put out was dated 7/20/09 so at this point they have to know these curves are way to aggressive). Although the average well starts out along their base case type curve as you can see (even though my table is VERY cluttered) the decline is much steeper and the n (or b) factor no where near as high as they are claiming. It is looking pretty evident to me that the average well is not going to even come close to their lowside case of 4.5 bcf.

I wonder when they will start telling people these wells are just not what they thought they were going to be?


[redacted]
[redacted] Oil & Gas
[redacted]
P.O. Box [redacted]
[redacted] Texas [redacted]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3 attachments — Download all attachments

[redacted]

SPE 134014

# Reserves Overbooking: The Problem We're Finally Going to Talk About

Grant T. Olsen, W.John Lee, and Thomas A. Blasingame, SPE, Texas A&M University




## Abstract

Oil and gas reserves estimates which honor disclosure requirements of the U.S. Securities and Exchange Commission (SEC) are critically important in the international oil and gas industry. Unfortunately, a number of E&P companies have allegedly overstated and subsequently written down certain reserves volumes in recent years. In some cases, the consequences have been quite adverse. We document some of these cases of reserves overstatements and summarize the consequences. Reserves write-downs are of obvious interest to numerous groups involved in the reserves estimation process and outcome, including estimators, managers, investors, creditors, and regulators. The magnitude and nature of recent overstatement cases, relative unfamiliarity with the SEC's inner-workings, and the Commission's new reserves reporting requirements, increase the need to examine critically reserves disclosures and reserves overstatements.


## Disclaimer

This paper discusses write-downs and alleged overstatements of oil and gas reserves. Information used to write this report has been obtained from extensive examination of the public record. Overstatements and violations of federal securities laws and actions by a company or its representatives are only alleged in the public record and, unless stated otherwise, any settlements discussed should be considered as made without admission of guilt. Write-downs can readily happen with even the best of intentions. We authors—and you readers—are not judge and jury. Our intent is to raise awareness about write-downs, overstatements, and observed consequences, and to promote the responsible reporting of oil and gas reserves.

## Overview of the Reserves Overbooking Issue

A number of E&P companies have, in recent years, allegedly overstated and subsequently written down certain reserves volumes reported to the US Securities and Exchange Commission (SEC). Operators including Shell, El Paso, Stone Energy, and Repsol YPF, among others, have found themselves in the spotlight—and courtroom—for alleged overstatements of their oil and gas reserves. Overstatements and write-downs have occurred for a variety of reasons, and have often been accompanied by significant adverse consequences. A stigma and discomfort surrounding overstatements exists within industry, as the topic has been labeled "the problem no one wants to talk about" (McLane 2001).

The SEC has roles, investigative processes, and enforcement procedures unlike any other organization involved with the oil and gas industry. However, the Commission's inner workings are not frequently discussed or well-understood by all of the groups these rules affect. The SEC's Modernization of Oil and Gas Reporting Requirements has made certain standards more flexible (e.g., elimination of the "one offset rule" and allowance of "reliable technologies"). Accordingly, engineers must now adjust to these new guidelines and deal with the possibility of disclosing previously unrecognized asset value without overstating reserves. The difficulty of this task, along with the technical "liberalization" and an enhanced "principles-based" emphasis in the rules, could create even greater potential for reserves overstatements than in the past.

Therefore, the magnitude and nature of recent alleged overstatement cases, relative unfamiliarity with the SEC's inner-workings, and the Commission's new reporting requirements have created a need to discuss openly reserves disclosures and reserves overstatements. Overstatements are not confined to particular reserves categories, asset types or locations, or filer size. However, overstatements are most likely to occur within the Proved Undeveloped (PUD) category. Reserves write-downs can create nearly instantaneous value destruction for shareholders. A study of case histories indicates that significant corporate and/or individual penalties may be associated with overstatements, along with the potential for class action lawsuits.

## Background

By a recent SEC definition, oil and gas reserves "are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." (US SEC 2008c). Reserves may be subdivided into proved, probable, and possible categories according to the degree of uncertainty associated with recovery of the volumes. In addition to being dependent on the manner in which the term is defined, reserves are also a function of numerous known and assumed technical factors including reservoir parameters, project costs, ownership, and commodity prices.

Reserves volumes and values of publicly traded oil and gas companies (e.g., on the New York Stock Exchange) are not directly reported on a company's balance sheet, but are rather attached to financial statements. Barry (1993) considered it "odd" for reserves not to be reflected in the balance sheet. Furthermore, he observed that "The volume of reserves is a corporation's Black Hole. It exerts a huge influence on everything else in its orbit, yet emits very little light." Since reserves are not part of the balance sheet per se, they are not subjected to audits by financial or accounting firms. However, filers commonly elect to have their reserves audited by third-party engineering firms.

Reserves are of significant importance to a variety of stakeholders including filers, investors, regulators, and politicians. An E&P company's financial health depends in large part on its stated oil and gas reserves. Financial measures such as finding and development costs, reserves replacement ratio, reserves life index and depreciation, depletion, and amortization are all impacted by a firm's oil and gas reserves. Furthermore, reserves are a vital instrument toward gaining access to capital markets: Credit ratings depend on reserves volumes, and bankers will commonly lend funds based on reserves as collateral. In his prepared testimony before the U.S. House Committee on Financial Services on 21 July 2004, Dharan (2004a) stated that reported reserves of oil and gas represented more than USD 3 trillion worth of value (and more than 70% of a typical E&P company's market value). In sum, many individuals and organizations have a great interest in the reporting of oil and gas reserves, and the quantities reported have important financial and geopolitical implications.

## The Evolution of "Reserves"

Given the somewhat disparate users and uses involved with oil and gas reserves, along with continuous advances in engineering and geological technology, the definition of "reserves" has been a moving target. The American Petroleum Institute (API) created definitions in 1936 as part of its annual studies of US oil reserves, and the American Gas Association (AGA) joined these studies in 1946 (Harrell and Gardner 2005). The Society of Petroleum Engineers (SPE) first adopted definitions for proved reserves in 1964. In 1975, the Energy Policy Conservation Act was passed, which led to definitions for proved reserves from the SEC in 1978. SPE and the World Petroleum Council published their "Petroleum Reserves Definitions" in 1997. That document had "seemingly subtle but often important divergences in interpretation" with the SEC definitions (Harrell and Gardner 2005). In 2007, the SPE/WPC/AAPG/SPEE released the Petroleum Resources Management System (PRMS), which sets forth an international standard for the definitions, codification, and evaluation of oil and gas reserves (SPE/WPC/AAPG/SPEE 2007). Although numerous organizations have weighed in on reserves definitions and filers are free to internally report reserves as they see fit, the SEC definitions are the legal standard by which filers must report their proved oil and gas reserves if they list their securities on U.S. Exchanges.

## SEC Modernization of 2009

The 1978 SEC definitions came under ever-increasing fire over the next three decades. As Lee (2009) outlined, some of the key changes which occurred since the 1978 definitions include the following:

- Significant advances in the recovery and characterization of hydrocarbons
- Growth and improvement of both spot markets and transportation for oil and gas
- Establishment of economic production from nontraditional resources (e.g., bitumen from oil sands)

Some of the most noteworthy updates resulting from the Modernization (US SEC 2008a,b,c), along with the perceived benefits, are presented below:

- While proved reserves must still be reported, probable and possible reserves may be disclosed at the option of the reporting company. Since companies commonly make investment and strategic decisions based on 2P reserves, disclosure of these additional categories should provide more transparency and relevancy for investors.
- Economically producible nontraditional resources, such as gas hydrates, synthetic oil and gas mined from coal and oil shale, and bitumen mined from oil sands, are now reportable as oil and gas reserves. A greater focus has been placed upon the "end product" than on the source of the product, and this will allow a broader view of an filer's reserves.
- Instead of requiring year-end pricing to calculate reserves, filers must use an average price that weights equally the price on the first day of each of the 12 months of the fiscal year. This change has the potential to remove some of the effect of the volatility inherent in product prices and serve as a more representative measure of recent oil and gas prices.
- Reserves may also be reported, at the filer's discretion, as a function of alternative price forecast(s). Such alternative pricing scenarios could give insight into the potential resiliency and/or upside of the filer's reserves portfolio.
- "Reliable" technologies may be used to determine reserves volumes. The regulations do not specify which technologies may be used, thereby implicitly allowing for the advent of new and incorporable technologies.

- Proved Undeveloped (PUD) locations greater than one offset away from a Proved Developed Producing (PDP) location, provided they meet the reasonable certainty criterion, may now be booked.

## Role of Third Party Firms

Third party engineering firms are commonly used throughout the oil and gas industry to audit reserves estimates made by filers, or to perform full reserves evaluations. As defined by the Modernization requirements of 2009 (US SEC 2008c), a reserves audit is "the process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities."

The Modernization guidelines do not require reserves audits of E&P companies. Should a filer indicate that a third party conducted an audit, process review, or any valuation of its reserves, however, the filer must make a number of disclosures regarding the third-party report. Specifically, the new regulations require "a brief summary of the third party's conclusions with respect to the reserves estimates" (US SEC 2008c). The guidance offered by SPE's 2007 Auditing Standards (SPE 2007), which does not have the force of law but which is mentioned in the "Supplementary Information" section of the new SEC rules, states that in rendering an opinion on the "reasonableness" of the estimated reserves, quantities and value "should reflect a quantity and/or value difference of not more than plus or minus 10%, or the subject reserves information does not meet minimum recommended audit standards." This +/- 10% variation may be interpreted as the amount by which qualified professionals can reasonably be expected to disagree when independently estimating reserves using identical information. Certain companies may elect to contract a third-party firm for a full evaluation of their oil and gas reserves, wherein the third party independently calculates the reserves based on data provided by the filer.

## Overstatements and Write-Downs

### From Proved to Unproved

A reserves write-down is a negative revision to oil and gas reserves estimates. A write-down should occur if and when it is discovered that reserves estimates are too high. According to Smith and Sheehan (1997), downward revisions of reserves are made "to reflect new information on existing well performance and/or changes in economic conditions (i.e., oil and gas prices, operating cost environment)." Write-downs are not necessarily a cause for concern among regulators or shareholders. For instance, reserves may be subject to a negative revision if product prices decrease over a given year. Such an occurrence represents a macroeconomic-level event to which filers are simply subject and over which they are likely have little control. Additional technical data regarding reservoir performance may necessitate a reserves write-down. There are other potentially "unavoidable" or "uncontrollable" factors, both large and small, which may result in or contribute toward a reserves write-down. This paper addresses reserves write-downs and focuses in particular on reserves overstatements, which represent largely *avoidable* reserves write-downs from the proved category to probable, possible, or sub-reserve "contingent resource" status. Overstatements can occur when there has been an intentional misapplication of or disregard for reserves booking guidelines.

### A Mixed Record in Industry

Previous articles have commented that reserves volumes for the US have a reputation for being conservative (Reservations About Reserves 2004), and congressional testimony offered by experts has indicated that reserves values are "generally stable and are subject to very few downward adjustments overall" (Dharan 2004b). A 1997 research article from the Energy Information Administration (EIA) (Morehouse 1997) had encouraging findings regarding audits of US reserves estimates submitted to the EIA since 1977: "most of the proved reserves estimates submitted to EIA are more than 90 percent certain to be recovered in the future and, in many cases, are more than 95 percent certain to be recovered." Proved reserves data requested by the EIA is "generally the same information" that filers must submit to the SEC (Wascak 2004.) However, the EIA data entails gross operated reserves, while the SEC requires net reserves (operated and nonoperated). At the individual field level, the EIA believes that the proved reserves estimate "almost always" falls within the range of "professional competence," and that at the aggregate level for the total volume of proved reserves presented in their annual reports, companies have a "99.999% probability" of recovering at least the physical volume that is estimated (Wascak 2004).

On the other hand, reserves overstatements have been acknowledged as "the problem no one wants to talk about" (McLane 2001). A previous study by Spear and Lee (1999) indicated a high degree of uncertainty for reserves estimates of 106 "leading oil and gas firms" during 1985–1994. Furthermore, between 2003 and 2008, E&P companies reported negative revisions of more than 9.3 billion net BOE (Hodgin 2009).

"Honest mistakes" in reserves estimation can and do happen. Furthermore, a handful of alleged overstatements should not cast doubt upon the reserves estimates of the entire petroleum industry. As Meyer and Zorn (2004) aptly stated in a 2004 Simmons & Company International report, "to broadly ascribe significant reserves risk to all E&P companies simply on the basis of the specific circumstances of a few is a dangerous game." However, this same report also states that "incidences of non-compliance with SEC proved reserves guidelines are numerous, each with their own specific case history and set of root causes." In certain instances of reserves write-downs from the recent past, the SEC and/or shareholder groups believed that the overstatements were not necessarily attributable to "honest mistakes." A number of reserves write-downs have equaled or exceeded 20% of a company's previously reported volumes. According to a former SEC Chief Accountant, "A 20% restatement of proved reserves is a humungous error.... not an oversight. It's an intentional misapplication of the SEC rules" (Macalister 2004).

So in light of the fact that alleged reserves overstatements and subsequent write-downs have occurred on a number of previous occasions, it is naive to assume that there will not be further instances in the future. The following anecdote was relayed by a SEC employee in 1964 (White 1964):

> "A rather unusual filing ... ascribed nearly 100 million bbl of oil and nearly 250 billion cu ft of gas to potential production from horizons 'not yet discovered.' This statement was volunteered in addition to an estimated 8 million bbl of proved undeveloped reserves which were subsequently reduced to 3 million bbl. Even this was a forced overestimation to allow for the remotest of contingencies. There had been only a little over 1 million bbl of developed reserves involved. After nine years, none of the 'potential' reserves has been discovered. Obviously this was not one of the better reports."

Although this comment was made nearly 50 years ago and the case pre-dates modern regulations, the attitude conveyed is telling and its tone has echoed through history.

**Causes of Overstatements**

McLane (2001) presented a number of reasons why reserves overbooking may occur. First, he states that poor estimating practices and ignorance may be responsible. Such practices of unsound technical work represent unintentional "errors of omission." These errors persist, despite ample availability of technical material covering reserves estimation including comprehensive texts on the subject (e.g., Cronquist 2001) and papers which specifically address "recurring mistakes and errors" in reserves estimation (Harrell *et al.* 2004 and Hodgin and Harrell 2006). When estimating year-end reserves for SEC reporting purposes, an insufficient understanding or improper application of SEC definitions would constitute a poor estimating practice and ignorance. A lack of adequate internal controls within a company would also be characteristic of shortcomings in this area.

Secondly, according to McLane, misguided incentives and competition for investors may be additional causes of reserves overbooking. Specifically, regarding misguided incentives, staff bonuses may set the tone for staff behaviors. If an engineer's compensation is dependent on achieving an aggressive level of reserves volumes, it may be difficult for the engineer to maintain objectivity during the estimation process. McLane discusses the significant pressure on managers to meet the high expectations of the equities market. McLane states that pressure exists "to push the envelope of credibility in efforts to buoy investor confidence and thus increase stock value." Michael Oxley, then-Chairman of the US House of Representatives Committee on Financial Services, quoted this same phrase during a Congressional Hearing on Oil and Gas Reserves in 2004 (Oxley 2004).

Third, McLane lists a number of human biases which may contribute to reserves overbooking. He describes biases affecting judgment under uncertainty and also biases affecting risk decisions. Some of the biases affecting judgment under uncertainty include overconfidence, availability, and anchoring. To be sure, any reserves estimate should be construed as requiring "judgment under uncertainty." Biases affecting risk decision are focused on the perception of risk with respect to investment decisions.

Last, according to McLane, reserves overstatements may reflect a lack of professionalism. He cites a number of behaviors, some of which are listed and consolidated below, that signify and encourage professionalism:

- Being fair and objective
- Accepting accountability for estimates and improving these estimates
- Disregarding the pressure to intentionally overbook reserves

**Consequences of Overstatements and Write-Downs**

McLane (2001) observed that many companies that have used "aggressive" reserves booking no longer exist because the temporal benefits of the practice disappear when the reserves have to be removed from the books. While the prospect of a company going out of business as a result of reserves overbooking may sound severe, our analysis of public records from numerous cases indicates that other penalties may also be significant. Sections that follow illustrate the significant potential liability for both individuals and corporations. As evidenced by the share price responses to admissions of substantial write-downs, overly aggressive booking practices can shake marketplace confidence. Reserves overbooking may lead to sudden and drastic value destruction for shareholders. Shareholder groups, in turn, have occasionally sought redress through class action civil lawsuits.

In addition to the "external" costs described above, an operating company may feel other consequences. For instance, McLane (2001) believes that "overbooking creates stress and tension within an organization." Most engineers and geoscientists, if pressured by management to "push the envelope" of technical credibility, would likely harbor or express these sentiments. It is possible—and in some cases documented—that employees or managers have left or even, more specifically, been asked to leave an organization due to reserves overbooking. Investigation of noteworthy cases even shows that management teams have been largely reshaped as a result of alleged overbooking.

## Enforcement and the Regulatory Environment

### The Securities and Exchange Commission (SEC)

According to the SEC's website, its mission "is to protect investors, maintain fair, orderly, and efficient markets, and facilitate capital formation," and "first and foremost, the SEC is a law enforcement agency" (US SEC 2010). The agency does not make claims regarding the preferrability of one investment over another, but rather aims to promote clear and full corporate disclosure to the investing public.

### General Enforcement Process

An investigation by the SEC may arise for a number of reasons: a routine review of SEC filings, tips from the public or news stories, referrals from other SEC investigations or government agencies (Larsen *et al.* 2008). Schaumann (2002) and Larsen *et al.* (2008) outlined the typical stages of an investigation. The investigation begins with an *informal inquiry*. At this point, the Commission does not have subpoena power and witnesses cooperate voluntarily. On the basis of the informal inquiry, the staff may request authority to conduct a *formal investigation*. If granted, the staff may then subpoena witnesses to testify.

The target of the investigation does not have the right to know that an investigation is being conducted, nor to make a statement. Typically, however, the target is issued a *Wells Notice*, which provides notification of the staff's intent. The target then has the option to respond via a *Wells Submission*, which may ultimately be used as evidence. After considering the Wells Submission, the staff makes a recommendation to the Commission. If a violation is believed to have occurred, the 5-member Commission may elect to pursue any or all of these three options:

- *File an action in federal court*—Seeks an *injunction* (either *temporary* or *permanent*) or civil penalties, and may bar the subject from serving as an officer or director of a SEC-regulated company.
- *Begin an administrative proceeding*—Held before an administrative law judge (employed by the SEC), who has the discretion to impose an array of sanctions, "ranging from the relatively innocuous to the severe" (Schaumann 2002). Such administratively-issued sanctions may include a *cease-and-desist order*, which is similar to an injunction.
- *Request that the Department of Justice (DOJ) bring a criminal action*—A DOJ investigation may be conducted in parallel to that of the SEC and may or may not be due to a referral from the SEC.

### Enforcement Trends

The most significant securities regulation laws since 1934 has been the Sarbanes-Oxley Act (SOX) of 2002. Passed in the aftermath of Enron's historic collapse in 2001, SOX is an anti-fraud measure comprised of numerous laws which address financial reporting by public companies. The Act requires that executives take individual responsibility for the accuracy and completeness of financial statements, requires companies to certify internal controls, and mandates a triennial SEC review of each company's financial statements (Dharan 2004a). SOX, however, does not explicitly mention or discuss oil and gas reserves reporting (Ryder Scott 2003).

The following figures reveal a number of interesting observations regarding SEC enforcement trends. **Fig. 1**, from the SEC's 2009 Performance and Accountability Report (US SEC 2009b), shows that the number of investigations opened by Commission has increased steadily since 2007.

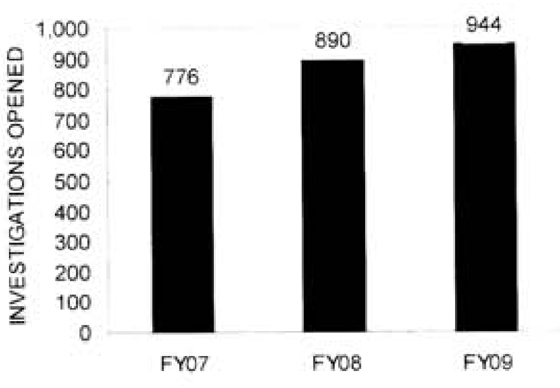


**Fig. 1—Investigations opened by the SEC in 2009 are up 20% from 2007 (adapted from US SEC 2009b).**

**Fig. 2** displays that while enforcement cases brought by the SEC are distributed among a number of different areas, there is an historical concentration in the area of financial disclosure cases (US SEC 2009b). (Statements pertaining to reserves constitute an example of "financial disclosure.")

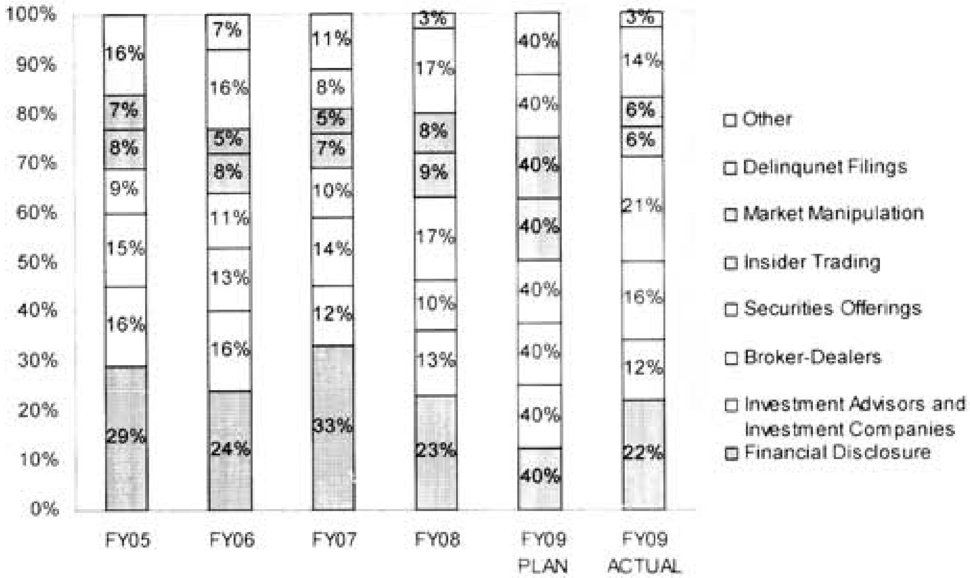


Fig. 2—Financial disclosure cases are the most common type brought by the SEC (adapted from US SEC 2009b).

**Fig. 3**, which should be of particular importance to reserves evaluators and executives who vouch for the legitimacy of publicly-disclosed financial information, provides an indication of the frequency of individual and/or corporate SEC settlements for "misstatement cases" (Larsen *et al.* 2009). The data show post-SOX SEC settlements have included an 'individual' component more often than not.

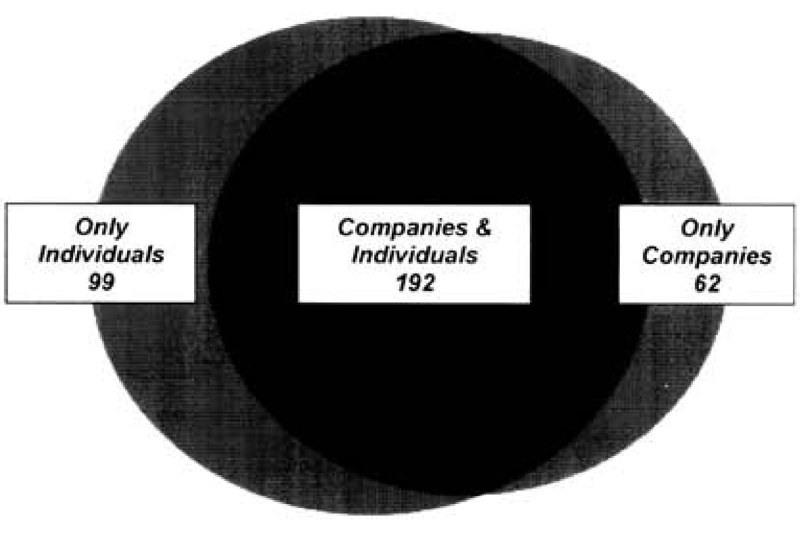


Fig. 3—SEC settlements for post-SOX misstatement cases most commonly include settlement with individuals (adapted from Larsen et al. 2009).

In summary, the authority and investigation count of the SEC are increasing, financial disclosure cases are the most common type brought by the SEC, and settlements are frequently made between the SEC and individuals.

## Regulation, Documents, and Guidance Related to Reserves Disclosures

The Energy Policy and Conservation Act of 1975 required the SEC to "take such steps as may **be** necessary **to** assure the development and **observance of accounting practices to be followed** in the preparation **of** accounts by persons engaged, in whole or in part, in the production **of** crude oil or natural gas in the United States" (42 US Code 77 2008). "Rule 4-10" established definitions for "proved reserves" and other terms of interest used in the oil and gas industry. In 1978, Accounting Series Release Number 253 and Statement of Financial Accounting Standards 19, Financial Accounting and Reporting by Oil and Gas Reporting Companies, were released by the SEC and the Financial Accounting Standards Board (FASB), respectively. FASB published SFAS 69, Disclosures about Oil and Gas Producing Activities–an Amendment of FASB Statements 19, 25, 33, and 39, in 1982 (FASB 1982). Other noteworthy documents include Industry Guide 2, SEC Staff Accounting Bulletin Topic 12 (1997), SEC Clarification of Oil and Gas Reserve Definitions and Requirements (2001), and SEC Exemption to Production Testing in Deep Water Gulf of Mexico (2004) (Etherington 2009).

Under powers granted by the 1934 Exchange Act, the SEC has the authority to establish financial reporting and accounting standards. Since 1973, the SEC has designated the FASB as being responsible for establishing such standards (FASB 2010b). Through June 2009, FASB communicated accounting standards to all industries by issuing a number of "Pronouncements," including Statements of Financial Accounting Standards (SFAS), Interpretations, Staff Positions, and Technical Bulletins (such as those mentioned above). As of July 2009, FASB has streamlined its communications with the Accounting Standards Codification (ASC), and any (previous) accounting literature outside of the Codification is non-authoritative (FASB 2009). Oil and gas accounting guidelines were set forth in "Extractive Activities–Oil and Gas (Topic 932)." In January 2010, FASB revised the topic to be aligned with the SEC's Modernization of the Oil and Gas Reporting Requirements (FASB 2010a).

Oil and gas reserves volumes for US-based companies are disclosed annually to the SEC and investors in conjunction with a *Form 10-K*. (Foreign issuers file a comparable document entitled *Form 20-F*.) Most companies are also required to file a quarterly report known as *Form 10-Q*. Certain intra-quarter material events call for a Form 8-K to make the important information public to shareholders. If there are certain intra-quarter material events, a *Form 8-K* ("current report") is filed to make public the important information to shareholders. Form 8-K filings are relatively common and may be necessitated by a variety of different events, but the information disclosed may have the potential to significantly alter a corporation's share price. The expectation or specifics of a reserves write-down may be communicated via Form 8-K.

### Potential "Triggers" for Reserves Inquiries

Although a previous section mentioned briefly some potential causes for an SEC investigation, the following is a more comprehensive list compiled from multiple sources (Hodgin 2009, Roesle 2007 and Schaumann 2002) that gives insight into items which may serve—independently or in concert—as the impetus for a reserves inquiry or investigation:

- History of negative reserves revisions
- Partner activity, press release, or revision
- History of SEC infractions (e.g., in other, "non-reserves" areas)
- Potentially questionable press release issued by filer
- Annual reports that don't conform to press releases
- Negative publicity
- Mandatory triennial SOX review
- Self-reported problems
- Unusual stock volume or movement
- Whistleblowers
- Response to an SEC comment letter

The SEC currently employs two petroleum engineers who are responsible for monitoring compliance to the Commission's standards for reserves disclosures (Meyer and Zorn 2004).

### Comment Letters

The SEC regularly issues *comment letters* in response to issuer filings. Any number of topics may be addressed in a comment letter, such as financial and accounting details, controls and procedures, executive compensation, legal proceedings, and reserves volumes. The comment letter requests a response to the questions raised by Commission. Certain comment letters and response letters pertaining to disclosures made after 1 August 2004 are made public through EDGAR, the Electronic Data Gathering, Analysis, and Retrieval system. (Other forms, including a company's 10-K, must be filed via EDGAR and are in turn also publicly available through the system.) However, if a company requests confidentiality, they may submit a redacted version—without the confidential information—to be made available publicly in addition to their unfiltered response to the Commission (US SEC 2004a).

Reserves volumes are commonly questioned in comment letters to oil and gas companies. A search for reserves-related comments on EDGAR clearly illustrates that the SEC is indeed actively examining the reserves data provided by issuers.

Questions posed by the Commission can be general (e.g., a request for a company's detailed reserves report) to very specific (e.g., requests about particular assets or wells). Company responses can yield further questions and requests for clarification. Two examples of reserves-related inquiries from SEC Comment Letters are presented below. These are only two brief examples of many which pertain to reserves volumes.

In a Comment Letter to American Oil & Gas regarding filings from 2005-2006, the Commission required further commentary on reserves revisions (Feiten 2007):

> We note significant oil reserve revisions in 2004 and significant gas reserve revisions in 2005. Please provide us with the reasons for these revisions.

Regarding Cabot Oil & Gas Corporation's 2006 Form 10-K, the Commission wrote a comment letter and sought additional details regarding Canadian PDP reserves (Schroeder 2008):

> Please provide us with a graph over time of production through the latest month the data is available for each your wells in Canada. Include on each graph your forecast of future production and reserves as of December 31, 2006.

**Types of Write-Downs**

Comment letters may result in a reserves write-down. Roesle (2007) identified two different types of negative revisions: a *de-booking* and a *restatement*. A de-booking "typically results from [an] SEC request to remove certain reserves from the next annual filing" and is "rather common." A restatement "is a much more serious result, particularly under SOX, as it requires the issuer to retroactively 'correct' past reserves disclosures and recalculate earnings." In the event of a reserves restatement, the US Department of Justice will likely open an investigation into the matter. The Justice department can issue both civil and criminal charges (Labaton and Gerth 2004). Additionally, corporate penalties may be triggered under SOX (Hodgin 2009).

**Corporate and Individual Liability**

The SEC's Division of Corporate Finance has issued reminders about individual liability that have been directed specifically to those involved with the reserves estimation process (US SEC 2001):

> The SEC staff reminds professionals engaged in the practice of reserve estimating and evaluation that the Securities Act of 1933 subjects to potential civil liability every expert who, with his or her consent, has been named as having prepared or certified any part of the registration statement, or as having prepared or certified any report or valuation used in connection with the registration statement. These experts include accountants, attorneys, engineers or appraisers.

Schaumann (2002) provides details on the legal liability associated with securities disclosures. Information which is said to rely on subjective analysis and judgment is referred to as "soft" information. Because of the potential of soft information to mislead investors, the SEC established safe harbor rules in 1979 for forward-looking statements containing soft information. These statements are to be made "in good faith" and the company has a duty to provide updates as new information becomes available. Further legislation brought an additional safe harbor act, the 1995 Private Securities Litigation Reform Act. Under this act, protection is afforded according to two alternative means: a plaintiff cannot "prove that the forward looking statement was made with actual knowledge that it was false or materially incomplete"; and adequate cautionary statements made by the defendant.

According to Larsen *et al.* (2008), 88% of individual settlements made with the SEC include a disgorgement payment. As previously mentioned, the SEC may also seek an injunction, which is "awarded for the purpose of requiring a party to refrain from doing or continuing to do a particular act or activity… The injunction is a preventative measure which guards against future injuries rather than affording a remedy for past injuries" (Gifis 1996). Certain parties in the El Paso reserves overstatement case, for instance, were enjoined in the 2008 SEC complaint.

## Shareholder Lawsuits

**Class Action Trends**

In light of the fact that reserves overstatements have been a principal or contributing factor in a number of class action lawsuits, it is necessary to make a few brief comments regarding their unique nature. A class action is defined as "a lawsuit brought by a representative member(s) of a large group of persons on behalf of all the members of the group" (Gifis 1996). McArthur (1996) has written extensively on class action lawsuits in the petroleum industry and commented that "the oilfield is no stranger to class actions." He claims that class actions have been used in drilling fund and partnership fraud cases, stock cases, and royalty cases. The "archetypal" class action involving securities entails stock price inflation by means of a misrepresentation or omission.

Recent documentation from the National Economic Research Associates (NERA), presented in **Fig. 4**, shows that class action lawsuits are relatively common in the energy industry when compared to filings in other industries (Plancich and Starykh 2009).

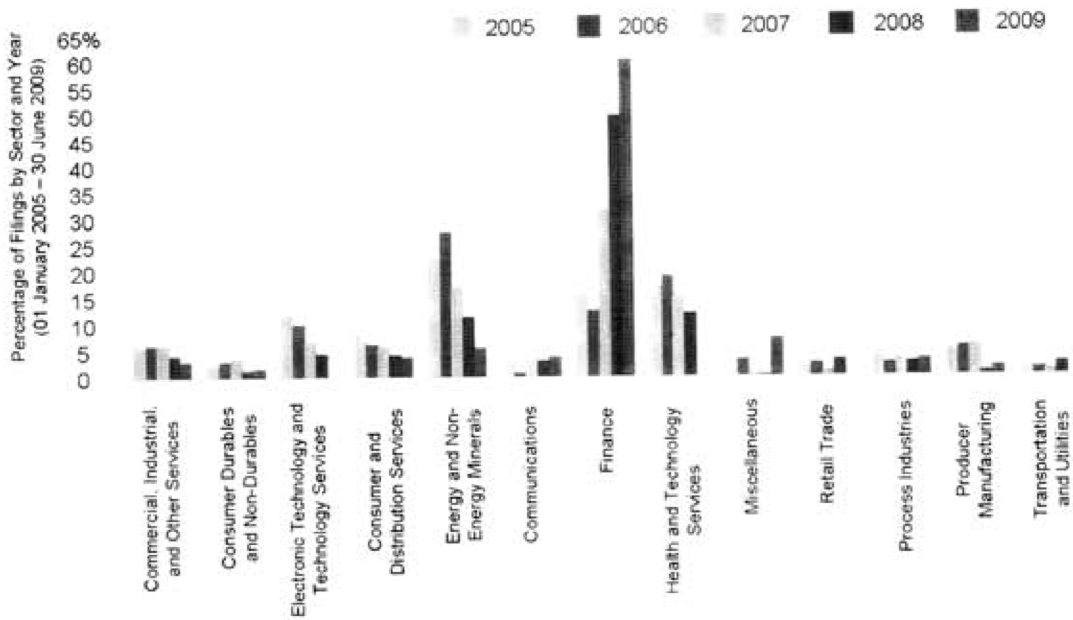


**Fig. 4—Preponderance of energy-related class action lawsuits is decreasing but historically high compared to those filed in other sectors (Plancich and Starykh 2009).**

Furthermore, the same NERA research indicates that for class action settlement values in 2008, the median was USD 8.0 million and the average USD 43 million. Settlement values have, on average increased significantly since the passage of Sarbanes-Oxley. Investor losses are said to be the most influential factor in determining settlement amounts. Another interesting finding, again courtesy of NERA (Plancich and Starykh 2009), is presented in **Fig.5**, which shows investors commonly arrive at settlements that are a mere fraction of their losses. Additionally, the data indicate a nonlinear relationship between losses and settlements. Investors who suffer higher losses will likely settle for a disproportionately lower amount relative to those suffering lower losses.

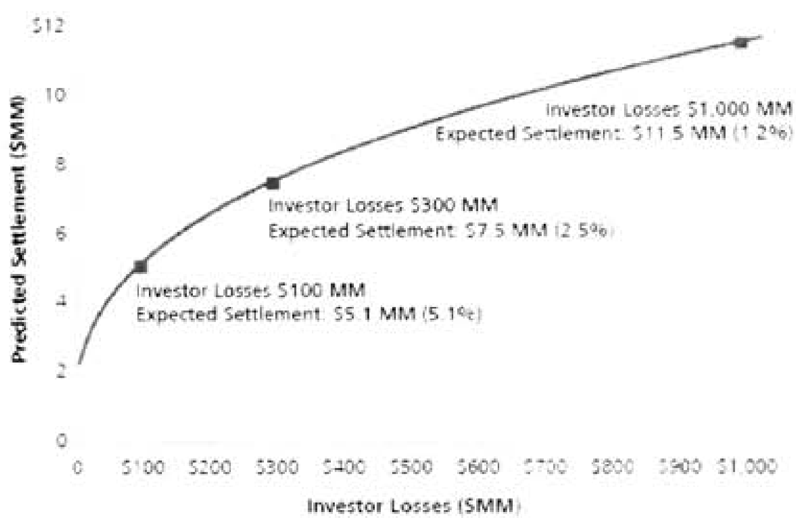


**Fig. 5—Class action settlements increase non-linearly with investor losses (from Plancich and Starykh 2009).**

## Case Studies

### Royal Dutch Shell Group (Shell)

Shell's international recognition and the magnitude of its 2004 reserves write-down make it likely the best-known alleged reserves overstatement case. The company announced a 3.9 billion BOE reduction in proved reserves on a 9 January 2004 conference call (Shell/Fair Disclosure 2004a). The Group Chairman was not on the conference call in which the reserves write-downs (or "recategorizations") were communicated to analysts, and received criticism as a result (Davis 2004). The E&P CEO was also absent from this call. Company representatives acknowledged that reserves audits were completed internally, with the aid of a contract reservoir engineer, and the write-down was associated with a review prompted by "part of our normal stewardship of the assets." Furthermore, representatives stated "there is no material effect on financial statements for any year up to and including 2003," and that "most of the reserves will be rebooked in the proved category over time" (Shell/Fair Disclosure 2004a). The value of Shell Transport's American Depository Receipts dropped 6.9% on 9 January 2004 as a result of the announcement (Pennsylvania Employees Retirement System v. Royal Dutch / Shell Transport 2005).

On 5 February 2004, Fourth Quarter 2003 results and additional write-down details were presented in a conference call (Shell/Fair Disclosure 2004b). As part of this call, the Group Chairman apologized for his absence on the previous month's conference call, it was disclosed that the group was "on credit watch," that class action shareholder lawsuits had been filed, and that it would be necessary to revise previously filed financial statements. Regarding the recategorizations, the Group Chairman stated "As soon as that came to my attention, it was a matter of all hands on deck, and I remember writing down the words 'get the facts and do the right thing....'" Later in the call, an analyst asked the Shell team if it would be appropriate for the Group Chairman to resign.

At the time of the alleged overstatement, the company allegedly had a "Byzantine dual holding structure," in which Royal Dutch Petroleum Company was based in The Hague, and Shell Transport and Trading Company was headquartered in London. Some observers believed this structure led to lax oversight (Mouawad, 2009). These parent companies owned shares in holding companies ("the group") which engaged in operational activities (US SEC 2004c). Early reports, including one from Meyer and Zorn (2004), stated the write-down was due in large part to the fact that projects booked as proved undeveloped between 1996 and 2002 in areas such as Australia and Nigeria had not, in fact, "progressed to their expected technical and commercial maturity." Reportedly, Shell and its partners had yet to receive government approval for a natural gas development, known as Gorgon, in Australia. (ChevronTexaco, a partner in this project, did not include Gorgan estimates as part of its proved reserves.) Additionally, securities analyst Fadel Gheit commented that companies with operations in Nigeria were likely under pressure from that nation's government to inflate reserves. Since production quotas are assigned to OPEC member countries on the basis of proved reserves, "it is in an OPEC country's best interest to put pressure on filers to motivate them to book more reserves" (Kopytoff 2004).

Ultimately, the alleged overstatement would prove to be 4.47 billion BOE, or about 23% of the company's total. A joint investigation was conducted by the SEC and Financial Services Authority (FSA), and Shell settled claims with the regulators for USD 120 million and BP 17 million (or USD 28 million), respectively, without admitting to or denying the findings of the Commission. The SEC alleged that Shell's overstatement stemmed from:

- "its desire to create and maintain the appearance of a strong Reserve Replacement Ratio"
- "the failure of its internal reserves estimation and reporting guidelines to conform to applicable regulations"
- "the lack of effective internal controls over the reserves estimation and reporting processes"

The SEC complaint stated that Shell had internal "excessively permissive" guidelines that did not adhere to those of securities regulators. Furthermore, Shell did not maintain adequate internal controls and did not ensure that its employees were well trained regarding SEC disclosure requirements. The complaint also alleges that Shell did not ensure timely compliance with Rule 4-10 by lowering proved reserves estimates despite internal events and relevant signals dating back to January 2002.

Furthermore, the SEC complaint shed light on the areas which constituted the majority of the recategorization:

- Australia—Shell carried reserves on the Gorgan project dating back to 1997, despite the lack of a market, development plan, and firm commitment to invest in the project.
- Nigeria—Reserves did not acknowledge license expiration and estimates were not made according to "existing conditions" as defined in Rule 4-10.
- Oman—Petroleum Development of Oman (PDO), partly owned by Shell, lacked a development plan on which to base reserves volumes; certain volumes were "not supported by any identified projects."

After settling with the Shell Group, an SEC official vowed "As our investigation continues, we intend to focus on, among other things, the people responsible for Shell's failures" (US SEC 2004b). Furthermore, it was reported in March 2004 that the US Justice Department opened an investigation into whether Shell executives violated any laws (Labaton and Gerth 2004). In June 2005, the Justice Department investigation was closed and no action was taken against Shell. Then, in August 2006, it was announced that the SEC would not pursue charges against the (former) Group Chairman (Robertson 2006).

A number of lawsuits in the United States followed the recategorization announcement. The reference class action complaint alleges a number of shocking details (Pennsylvania Employees Retirement System v. Royal Dutch/Shell Transport 2005). In October 2002, an email from the E&P CEO to the Group Chairman stated that "I must admit that I become sick and tired about arguing about the hard facts and also cannot perform miracles given where we are today... If I was interpreting the disclosure requirements literally (Sorbanes [sic]-Oxley Act etc) we would have a real problem." The E&P CEO wrote the

Group Chairman in November 2003 that he was "becoming sick and tired about lying about the extent of our reserves issues and the downward revisions that need to be done because of far too aggressive/optimistic bookings." In December 2003, a "script" was prepared which discussed the need to disclose noncompliant reserves volumes. The E&P CEO replied that "this is absolute dynamite, not at all what I expected and needs to be destroyed." The Group Chairman, CFO, and E&P CEO left the company shortly after the reserves revelations (CNN/Money 2004).

The class action lawsuit named and aligned claims against certain defendant groups: "Shell Group Defendants" Royal Dutch, Shell Transport, the former Group Chairman, the former E&P CEO, and former CFO; "Individual Defendants" former Group Chairman, former E&P CEO, and former CFO; and financial auditors PwC UK and KPMG International. The first two counts, against the Shell Group Defendants and financial auditors, respectively, alleged violations of Section 10(b) of the 1934 Securities Exchange Act and Rule 10b-5 Promulgated Thereunder. The third count was against the individual defendants for Violations of Section 20(a) of the 1934 Securities Exchange Act.

Certain analysts had believed that Shell would need to merge with another company by the end of 2004 as a result of the scandal (Mouawad 2009), although this did not come to pass. Reserves booking procedures of other major integrated oil companies were questioned by the SEC in the wake of the Shell overstatement (Kopytoff 2004). Analyst J.J. Traynor of Deutsche Bank commented, "We remain convinced that reserves bookings are a sector-wide issue, albeit amplified at Shell" (BBC News 2004).

In September 2008, a settlement with US investors was approved in which Shell paid more than USD 80 million to shareholders (Egoy 2008). In 2009, an Amsterdam court declared binding a USD 352.6 million settlement with non-US shareholders (Stichting Shell Reserves Compensation Foundation 2009).

**El Paso Corporation**

El Paso's reserves data attracted much attention after the publication of a November 2002 Houston Business Journal article (Perin 2002). In this article, a veteran reservoir engineer with the Houston-based company stated that after El Paso acquired Coastal Corporation, engineers at the company were asked to "clean up the books" and remove reserves volumes that did not meet SEC criteria. However, the engineer reported that "management interfered with engineering decisions" and issued an order to return the reserves to the proved category. The company, according to the engineer, was in some cases attributing reserves to projects that would not be developed for 10 years. A second engineer claimed that El Paso had recently been questioned by the SEC regarding proved undeveloped locations greater than one offset location away from proved developed locations.

On 17 February 2004, the company disclosed a write-down of 1.8 Tcf, or approximately 40% of its previously reported proved reserves. The organization's new CEO announced that in October 2003, after performing a number of field reviews, he believed that it was necessary to have a "fresh set of independent eyes" recalculate reserves volumes for the end of the year (El Paso/Fair Disclosure 2004a). The majority of the negative revision involved proved undeveloped locations that no longer met key technical and commercial hurdles (Meyer and Zorn 2004). The company later restated earnings for a number of prior years, resulting in a USD 1.7 billion decrease in stockholders' equity (US SEC 2008d).

Alleged details emerged from a SEC complaint that was filed more than four years later against El Paso Corporation, two of its subsidiaries, and five former employees of El Paso Exploration & Production Company (EPEP) (SEC v. El Paso 2008). The complaint stated that a former EPEP President and former Senior Vice President "aggressively sought to maximize oil and gas reserves ... The three Divisional vice presidents, in response to the pressure to maximize reserves, overstated reserves totals" in the following ways:

- Recording proved reserves to unproved reservoirs
- Assigning reserves despite a lack of sufficient engineering and geological data
- Failing to reduce reserves volumes based on performance

Furthermore, the company failed to maintain adequate internal controls. Financial statements dating back to 1999 were restated. Details on the degree to which certain assets were affected can be gleaned from the SEC complaint and preliminary data announced in the February 2004 conference call. Selected highlights are presented below:

- South Texas—The largest revision, in which Vicksburg sands for PDP and PUD reserves were adjusted to account for smaller drainage areas in low-permeability sands and well interference owing to larger drainage areas in high-permeability sands. Reserves data for PUDs were not immediately adjusted to account for post-drill EURs, which indicated the company would recover only 67% (subsequently lowered to 39%) of pre-drill estimates for particular locations. 25% of the South Texas write-down was due to the company using an outdated study on a single field to justify a 7% minimum decline rate when a 12- to 13% minimum decline rate was more accurate.
- Rocky Mountains /Coalbed Methane—Due in part to Raton Basin locations found to be draining only 80 acres (as opposed to historical bookings at 160 acres). Also, to create viable locations, did not use current economic, operating, and cost conditions in accordance with Rule 4-10. Booked 150 PUD locations on the basis of three test locations and two producing wells.
- Gulf of Mexico—Mechanical failures, performance and revised geologic interpretation. (Not cited in SEC complaint.)
- Brazil—Lack of gas sales agreement for Camamu Basin. (Not cited in SEC complaint.)

By the end of June 2004, EPEP had "a new leadership team not only at the top, but at least two levels down" and seven new members on the El Paso Corporation's Board of directors (El Paso/Fair Disclosure 2004b). The five EPEP executives named in the SEC complaint settled with the Commission for either USD 75,000 (EPEP president) or USD 40,000 (EPEP senior VP and three divisional VPs) (Plourd 2008). Despite settling for USD 235,000 with the five employees (who did not admit guilt), the SEC did not fine the company (Gold 2008). Both El Paso and each of the executives did, however, agree to injunctions against future violations of the securities laws at issue. (U S SEC 2008d).

Beginning in 2002, approximately one and one-half years before the reserves write-down, a number of class action lawsuits were filed against El Paso (and related parties) for various securities law violations (Wyatt v. El Paso Corporation 2006). The reserves write-down resulted in additional lawsuits, which were ultimately consolidated. The suit claims that El Paso's share price dropped approximately 18% in response to the reserves announcement in February 2004. El Paso agreed to pay USD 273 million to settle the case (Wyatt v. El Paso Corporation 2006).

**Stone Energy Corporation**

Stone Energy Corporation, based in Lafayette, Louisiana and with assets concentrated in the Gulf of Mexico, Rocky Mountains, and Williston Basin, announced on 6 October 2005 that the company had recently retained services of a third-party firm to perform a reserves review of all its fields (Stone Energy Corporation 2005a). The company stated that it would need to revise previous estimates by 171 Bcfe, or approximately 20% of its reported total at year-end 2004.

A press release issued on 8 November 2005 announced that certain financial statements dating back to 2001 would need to be restated (Stone Energy Corporation 2005b). Another press release, issued just two days later, announced that the company had received notice that the reserves revision would be the subject of an informal investigation by the SEC (Stone Energy Corporation 2005c). In December, Stone detailed the preliminary findings of an independent review on the reserves revision (Stone Energy Corporation 2005d). The negative revision resulted from a number of factors, including:

- Lack of "adequate internal guidance or training on the SEC standard for estimating proves reserves."
- "Some former members of Stone management failed to fully grasp the conservatism of the SEC's 'reasonable certainty' standard of booking reserves."
- "There was an optimistic and aggressive 'tone from the top' with the respect to estimating reserves. Some on the Stone technical staff felt pressure to interpret the geological and engineering data in an aggressive manner..."

Subsequently, Stone's former CEO left the company's board of directors. Furthermore, management was advised by the board of directors to request resignations of two other individuals involved with the write-down (Snow 2006). No fewer than 16 law firms announced class action lawsuits in the months following the negative reserves revision. A consolidated class action complaint was filed in June 2006 in US District Court for the Western District of Louisiana (El Paso Fireman and Policeman's Pension Fund v. Stone Energy Corporation 2006). Along with Stone, it also named the former and subsequent CEOs and CFOs as defendants. The complaint stated that the company overstated its reserves for four and one-half years despite using the services of a third-party firm, and that the former CEO:

- "Re-drew geological maps of oil and gas reservoirs to manufacture false reserves numbers."
- "Violated SEC requirements for booking proved reserves."
- "Intimidated and verbally abused Stone employees for calculating proved reserves that were lower than Canty wanted."

According to the complaint, Stone's senior VP for exploitation and its reservoir engineering manager aided the former CEO in orchestrating the overstatement. Also, it states that "Company insiders with knowledge of the fraud were selling their personal holdings of Stone common stock at prices they knew were artificially inflated by the proved reserves overstatement." and that shares dropped 30% as a series of announcements revealing the truth about Stone's reserves were made between 6 October 2005 and 10 March 2006.

Stone received notice from the SEC in April 2007 that it would not pursue an enforcement action in connection with the alleged reserves overstatement (Stone Energy Corporation 2007). Class action claims against two of the individual defendants were dismissed in August 2007 (Stone Energy Corporation 2008). In January 2010, a class action settlement was preliminarily approved for USD 10.5 million (Stone Energy Corporation Securities Litigation 2010).

**Repsol YPF**

Repsol YPF, based in Madrid, Spain, announced in January 2006 that reserves volumes for year-end 2005 would be reduced by 1.25 MMBOE, or approximately 25% of the volume reported at year-end 2004 (Repsol YPF 2006). Most revisions were in Bolivia (659 MBOE) and Argentina (509 MBOE). When disclosing the revision, the company cited "Changes in legal and contractual framework (New Hydrocarbon Law in Bolivia)" and "Field performance and new data yielding a deeper understanding of the affected reservoirs" as the two main reasons for the write-down. Projected economics deteriorated for certain Bolivian opportunities as a result of the new hydrocarbon law, and estimates in various Argentinian fields were reduced. After the announcement, Spain's securities regulator, the Comisión Nacional del Mercado de Valores (CNMV), opened an investigation into the overstatement.

A consolidated class action complaint filed with the United States District Court for the Southern District of New York alleged securities law violations against the company, its CEO, and former CFO (Reynolds v. Repsol YPF 2006). According to the lawsuit, an internal investigation by the company found:

- "The process for determining reserves… was flawed from 1999 to 2004."
- "A lack of proper understanding of and training on the requirements of the SEC for booking proved reserves."
- "An unwillingness to accept personal responsibility for reporting internally adverse facts regarding reserves."
- "Undue optimism regarding the technical performance of the fields and (for Bolivia) commercialization."
- "Systemic flaws in the Company's internal control structures."

The consolidated class action alleged per-share price decreases of 7% (USD 2.12) and 4.79% (USD 1.34) on the day of and day following the revision announcement, respectively. A settlement of USD 8 million was reached with shareholders in 2007.

**Analysis of Cases**

Arguably, the most important factor regarding some alleged reserves overstatement cases is that they were entirely avoidable. Through more education on SEC regulations, stronger internal controls, and/or a greater emphasis on ethics, many of these overstatements would not have occurred. The write-down or recategorization of certain volumes rapidly destroyed significant shareholder value as few events can. Allegedly, overstatements have, in certain cases, erased as much as 30% of share prices. Although not discussed at length here, legal expenses and attorney's fees can be significant in class action litigation and are further costs ultimately borne by shareholders. In light of this value destruction, shareholders with a sizable position in an E&P company are concentrating their risk for reserves overstatement.

## Implications of Modernization

The reserves booking guidelines under the modernized SEC rules are more flexible than the previous standards. For example, filers may now book PUD locations that are greater than one well spacing away from a producing well. Additionally, the requirements make allowance for using "reliable" technologies. The new regulations are, in effect, more "principles-based" than those previously employed by the Commission.

More disclosure is required as a result of this enhanced flexibility. For example, reliable technology must be disclosed, at least in general ways. Additionally, information is required regarding the concentrated geopolitical political risk facing a filer. Subpart 229.1200 (Items 1201 through 1208) of Regulation S-K is new under the Modernization and focuses entirely on reserves-related disclosures. PUD locations are limited to a 5-year development timeframe. Certain filers may have PUD locations that will need to be de-booked at the end of 2009.

However, the new regulations do not address certain issues or solve problems that were alleged to have been key factors in certain overstatement cases we have highlighted, such as a disregard for the rules, weak internal controls or human biases. No matter the definitions, the principles of the industry and its members will ultimately determine how "level" the playing field is. Companies may ignore the rules, just as they have allegedly done in the past. They may do so in particular with the new flexibilities afforded under the PUD booking and reliable technology guidelines mentioned above. Furthermore, the reliable technology principle may inadvertently lead to the incorporation of technologies (into reserves calculations) before those technologies are genuinely understood by certain engineers. Probable and possible reserves represent additional areas of disclosure that may be reported too aggressively and without using proper evaluation procedures.

For these reasons, some believe that the risk of reserves write-down may increase under the new regulations. According to Darbonne (2009), Geoff Roberts of the Oil & Gas Asset Clearinghouse believes that "the [Modernization] regime opens the company-reporting process to serious potential for misuse or abuse by aggressive public companies." It is now, of course, too soon to gather any empirical evidence to support or refute such intuitive claims.

Regardless of the requirements in place, estimating reserves will likely always be an inexact and subjective science. Authors have acknowledged that "The mere physical attributes of the asset class—miles below the surface, significant natural variability within the oil and gas reservoir—make conventional engineering precision an impossible standard to achieve… The lack of precise definitional and engineering standards can naturally lead to a range of interpretive outcomes, both conservative and aggressive" (Meyer and Zorn 2004).

## Conclusions

We draw the following conclusions from this study:

- Reserves overstatements have occurred on a number of occasions, and for a variety of reasons, in the oil and gas industry.
- There is potential for significant corporate and/or employee penalties for cases of reserves overstatements, along with the possibility of class action shareholder lawsuits.
- There may be a greater risk for reserves write-downs as a result of the 2009 Modernization of Oil and Gas Reporting Requirements.
- Accurate reserves reporting should be an ethical and corporate mandate, as doing otherwise can destroy the credibility of management teams and produce significant civil penalties for both corporations and employees.

8 March 2011

Equity

Sector Review

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# Oil & Gas: N.A. Producers

## Flowing and Reserve per Barrel, and Debt Adjusted Reserve Benchmark Review

### Market Weight

**Stock selection**

Preferred: CNQ, NBL, OXY

Least preferred: APC, MUR

- As petroleum price proxies, investors discount near term changes which affect future discretionary cash flow and earnings of stocks owned or shorted. On average, the 14 companies in our coverage universe produce 55% natural gas. With a 27:1 WTI/HH pricing relationship vs. 6:1 energy equivalency, the 'parity relationship' argument can't be made.
- For 2011, only 30% of these E&Ps' natural gas output is hedged. None of these E&Ps have reduced 2011 cap ex vs. 2010, but they have shifted the mix to liquids (NGLs or oil). As pointed out in our 2/24/11 note, those current spending plans won't materially cause natural gas leveraged E&Ps' output to become quickly balanced with oil. As exploitation driven, and natural gas leveraged entities it's a ½ decade process or more without asset restructuring.
- Because management teams 'talk up' liquids today, we thought it worthwhile to look at stock valuation snapshots which compare Market Cap and Enterprise Value to **flowing barrel** and **proven reserves** to get a sense of what investors are paying, and to also look at another metric which companies' management use: **debt per reserves**.
- Why undertake this exercise? The energy stocks began a new month by rolling over after posting strong Jan and Feb performances. Clearly, there are cross currents. Seasonally, N.A. natural gas prices will drop with winter's end. Though oversupplied, the industry grew output 3% in 2010. But, WTI is @ $104/Bbl and Brent @ $116 given recent events in North Africa, and E&Ps chasing liquids growth one must ask how the stocks have fared at other times.
- It's marginal output change that investors are chasing even if it doesn't mean improved corporate ROACE. Some management teams have recognized the disconnect which is why they've entered into premium natural gas JVs, simply sold gas assets or issued equity to fund growth. But, those actions don't materially change the N.A. natural gas supply situation.
- From our vantage point, the upward turn of E&Ps stocks, that many investors seem to want to call, will be dependent upon N.A. natural gas market price stabilization and not oil. It's not atypical for E&Ps to seek the highest near-term production cash flow, but few N.A. E&Ps have ever tried to consistently balance oil output in N.A., which is a petroleum province that is leveraged towards natural gas. Instead, they went with the lowest exploitation risk option.
- **Conclusions**: Our BUY list remains limited, but one shouldn't fight the tape, and thus be market weighted with a bias towards liquids and not gas. Again, with JV partners overpaying to participate, open equity funding spigots, and a more efficient gas-producing industry mean the only saviours for natural gas may be an active hurricane season, hot N.A. weather, a robust US economy or Federally mandated U.S. gas consumption incentives. On our estimates, few will be generating high free cash flow levels with $90+ WTI and $4.15/Mcf Natural Gas.


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# **Benchmark Reviews:** Flowing Barrel, In Ground Reserve Valuation, and Debt Adjusted Reserve changes

During times of stock or commodity market uncertainty, it's good to look at past analogs. On average, most N.A. E&Ps have been public less than 25 years. So, one can't go back to the OPEC Oil Embargo era of the late 1970s or early 1980s, or even the Iraq vs. Kuwait war in 1990 to see how the E&P stocks behaved since many of today's US Large and Mid Caps or Canadian Seniors were fractionally sized in comparison.

As commodity proxies, not only do oil, NGL and natural gas prices change, but so does E&P investor perception about them. In order to address that reality, we opted to look at industry benchmark trends on the basis of **Market Cap** (Stock Price x Shares) and **Enterprise Value** (Market Cap plus Net Debt) **compared to daily BOE output (aka Flowing Barrel) and also on the basis of net proven reserves (an 'in ground valuation')**. Lastly, we thought it worthwhile to look at **debt per reserve changes and EBITDAX/Net Interest Expense coverage** since many company management teams emphasize debt/reserve adjusted growth rates.

E&P investors want to invest in companies that will benefit from positive pricing, cost or production changes. Today, with natural gas prices 4% of that of oil, most investors, not surprisingly, seek liquids (NGLs and oil) exposure because of the likelihood of weak intra-continental natural gas pricing for 2011, and beyond.

When one undertakes these exercises, investors can see that there aren't long-term or normalized benchmark trends. **Investors tend to be commodity price sensitive on a near-term basis and thus, such metrics vary annually.** We'd argue that investors really aren't focused long term; if they were, NAVs would matter more, and if they were accurate, there wouldn't be considerable corporate sale discounts.

**Here are our abridged conclusions:**

1. Not all natural gas leveraged E&Ps have low per-flowing-barrel valuations, and today with investors chasing liquids growth, they pay for liquids exposure.
2. An oil leveraged E&P like OXY may sell on high per-flowing-barrel metrics (Market Cap or Enterprise Value) some 25% greater than natural gas leveraged E&Ps which produce, on a percentage basis, 30-50% of OXY's liquids output and consume rather than generate meaningful free cash flow. So there are benchmark 'disconnects.'
3. Not surprisingly, natural gas leveraged E&Ps have lower 'flowing-barrel' and 'in-ground' valuations if they have low liquids exposure, e.g., ECA.
4. Geographic diversification (within N.A. basinally or globally) doesn't equate to higher flowing-barrel valuations.
5. When company managements emphasize future liquids growth, investors tend to gravitate towards the marginal barrel or Mcf in terms of future cash flow growth, but often ignore the challenge to generate corporate ROACE when one is predominately natural gas levered.

## Comparisons based on Per Daily Flowing Barrel

In the next two tables, we've compared Market Cap and Enterprise Value per flowing barrel. Please note that we've included year-end prices up to 2008 and average pricing (first day, 12-months) for 2009 and 2010 consistent with SEC reporting convention, the WTI/HH price ratio and the percentage natural gas output for each company over the last 15 years.

**Market Capitalization / Flowing Barrel**

| US LARGE CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 37,342 | 29,942 | 28,435 | 32,243 | 58,690 | 25,838 | 22,300 | 24,529 | 29,565 | 50,160 | 41,185 | 53,335 | 31,450 | 50,925 | 58,795 |
| Apache Corporation | 21,241 | 19,219 | 14,246 | 20,623 | 33,223 | 19,886 | 24,073 | 31,546 | 36,869 | 49,803 | 43,925 | 63,827 | 46,590 | 59,549 | 60,377 |
| Devon Energy | 38,054 | 22,515 | 15,069 | 19,684 | 23,678 | 12,797 | 13,991 | 21,672 | 27,461 | 44,831 | 54,283 | 64,161 | 44,807 | 51,431 | 54,033 |
| EOG Resources Inc | 25,142 | 19,455 | 13,956 | 11,445 | 34,397 | 24,392 | 25,025 | 28,389 | 41,202 | 74,397 | 58,508 | 76,246 | 49,992 | 69,727 | 60,149 |
| Murphy Oil Corporation | 27,440 | 23,546 | 19,050 | 24,346 | 26,236 | 33,249 | 34,167 | 55,064 | 68,207 | 95,037 | 107,358 | 155,019 | 63,588 | 67,012 | 79,338 |
| Noble Energy | 24,171 | 15,184 | 10,622 | 11,596 | 27,570 | 19,942 | 21,812 | 25,037 | 37,657 | 48,879 | 45,507 | 68,684 | 40,117 | 60,284 | 69,336 |
| Occidental Petroleum | 18,907 | 25,363 | 13,423 | 18,688 | 19,487 | 20,935 | 20,867 | 29,882 | 40,886 | 56,678 | 67,125 | 109,357 | 80,698 | 98,737 | 107,532 |
| Pioneer Natural Resources | 19,674 | 30,259 | 5,098 | 6,409 | 16,251 | 17,569 | 26,099 | 24,628 | 27,388 | 37,131 | 53,484 | 59,158 | 16,524 | 47,799 | 87,338 |

| MID CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 19,893 | 19,257 | 9,427 | 17,641 | 21,379 | 16,801 | 19,746 | 44,473 | 24,097 | 37,850 | 37,288 | 65,645 | 18,515 | 30,015 | 57,099 |
| Newfield Exploration | 35,538 | 24,823 | 20,909 | 21,460 | 31,455 | 19,537 | 22,198 | 24,661 | 33,164 | 57,781 | 53,549 | 68,863 | 26,509 | 59,883 | 74,626 |

| Canada Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resource | NA | NA | NA | NA | 11,015 | 8,256 | 9,424 | 14,753 | 22,324 | 48,241 | 49,369 | 64,802 | 38,133 | 67,868 | 76,291 |
| Encana Corporation | NA | NA | NA | NA | NA | 22,840 | 29,672 | 27,957 | 33,941 | 50,392 | 49,787 | 70,007 | 45,005 | 48,685 | 38,975 |
| Nexen Inc | 13,261 | 13,152 | 5,662 | 12,153 | 12,328 | 9,383 | 10,579 | 17,942 | 20,516 | 51,723 | 91,714 | 82,842 | 43,411 | 58,848 | 54,994 |
| Talisman Energy | NA | 13,982 | 7,703 | 11,549 | 12,352 | 12,044 | 10,621 | 18,856 | 22,971 | 41,329 | 37,372 | 41,759 | 23,434 | 44,530 | 54,590 |

**Percentage Natural Gas Output**

| US LARGE CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 72% | 73% | 67% | 62% | 57% | 58% | 58% | 55% | 56% | 56% | 54% | 52% | 55% | 61% | 61% |
| Apache Corporation | 65% | 63% | 60% | 57% | 54% | 53% | 55% | 53% | 49% | 46% | 46% | 53% | 53% | 50% | 50% |
| Devon Energy | 61% | 56% | 57% | 62% | 63% | 59% | 61% | 68% | 63% | 59% | 61% | 67% | 64% | 66% | 69% |
| EOG Resources Inc | 86% | 86% | 86% | 85% | 85% | 83% | 84% | 85% | 86% | 84% | 85% | 86% | 85% | 81% | 78% |
| Murphy Oil Corporation | 43% | 41% | 44% | 40% | 38% | 37% | 41% | 43% | 33% | 22% | 14% | 15% | 16% | 7% | 17% |
| Noble Energy | 63% | 68% | 70% | 71% | 71% | 71% | 68% | 65% | 60% | 53% | 58% | 56% | 57% | 60% | 63% |
| Occidental Petroleum | 31% | 29% | 30% | 27% | 28% | 26% | 23% | 20% | 18% | 19% | 20% | 20% | 21% | 23% | 23% |
| Pioneer Natural Resources | 52% | 53% | 49% | 49% | 52% | 52% | 51% | 53% | 63% | 63% | 64% | 53% | 55% | 57% | 55% |

| MID CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 82% | 72% | 72% | 71% | 70% | 62% | 63% | 64% | 62% | 62% | 62% | 60% | 70% | 75% | 76% |
| Newfield Exploration | 73% | 73% | 72% | 75% | 77% | 75% | 76% | 79% | 83% | 81% | 79% | 82% | 80% | 73% | 69% |

| Canada Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resources | 69% | 59% | 59% | 58% | 43% | 43% | 49% | 47% | 45% | 43% | 43% | 46% | 44% | 38% | 33% |
| Encana Corporation | 44% | 45% | 49% | 55% | 56% | 60% | 66% | 65% | 66% | 70% | 78% | 82% | 83% | 95% | 96% |
| Nexen Inc | 25% | 28% | 28% | 21% | 19% | 20% | 18% | 20% | 20% | 18% | 22% | 16% | 15% | 16% | 18% |
| Talisman Energy | 52% | 46% | 46% | 49% | 41% | 40% | 39% | 47% | 48% | 47% | 46% | 47% | 48% | 50% | 54% |

**Pricing**

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NYMEX WTI | 25.92 | 17.64 | 12.05 | 25.60 | 26.80 | 19.84 | 31.20 | 32.52 | 43.45 | 61.04 | 61.05 | 95.98 | 44.60 | 61.08 | 79.81 |
| NYMEX HH | 2.76 | 2.26 | 1.95 | 2.33 | 9.78 | 2.57 | 4.79 | 6.19 | 6.15 | 11.23 | 6.30 | 7.48 | 5.62 | 4.24 | 4.46 |
| WTI/HH Price Ratio | 9.4 | 7.8 | 6.2 | 11.0 | 2.7 | 7.7 | 6.5 | 5.3 | 7.1 | 5.4 | 9.7 | 12.8 | 7.9 | 14.4 | 17.9 |

Source: Company Reports, EIA, and SG Estimates

### Conclusions for Market Capitalization:

1. Valuations rise more with oil pricing or strong WTI/HH price ratios rather than natural gas prices alone.
2. Above average oil exposure is recognized, sometimes too much and so is 'liquids growth.'
3. Pure gas plays are penalized in the current market.
4. No real valuation distinctions amongst U.S. cap sizes or Canadian seniors.

## Enterprise Value Per Flowing Barrel

| US<br>LARGE CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 44,283 | 37,743 | 39,265 | 42,598 | 71,126 | 34,955 | 32,449 | 34,025 | 35,257 | 56,926 | 87,173 | 76,720 | 48,512 | 65,384 | 72,140 |
| Apache Corporation | 29,463 | 28,083 | 21,984 | 29,795 | 41,588 | 24,728 | 28,971 | 37,045 | 42,385 | 54,126 | 51,277 | 71,137 | 52,096 | 64,729 | 64,922 |
| Devon Energy | 43,099 | 24,459 | 20,500 | 30,951 | 29,175 | 30,102 | 28,128 | 33,840 | 35,984 | 51,836 | 66,056 | 74,220 | 53,201 | 61,822 | 58,210 |
| EOG Resources Inc | 27,999 | 23,789 | 19,937 | 16,727 | 38,916 | 29,003 | 31,229 | 34,248 | 46,332 | 75,827 | 60,488 | 80,165 | 54,701 | 75,719 | 71,633 |
| Murphy Oil Corporation | 28,603 | 25,385 | 22,267 | 27,732 | 30,374 | 37,494 | 40,733 | 63,370 | 69,226 | 95,309 | 110,517 | 162,998 | 63,154 | 68,778 | 78,162 |
| Noble Energy | 30,867 | 19,650 | 16,118 | 16,011 | 32,938 | 27,956 | 31,975 | 33,582 | 44,905 | 62,140 | 54,378 | 74,783 | 45,401 | 65,233 | 74,762 |
| Occidental Petroleum | 30,002 | 38,268 | 28,818 | 29,138 | 27,267 | 25,544 | 29,029 | 36,279 | 44,513 | 56,965 | 68,589 | 109,036 | 82,307 | 100,999 | 110,948 |
| Pioneer Natural Resources | 21,460 | 49,634 | 17,391 | 18,638 | 29,274 | 31,287 | 40,733 | 34,561 | 40,156 | 48,618 | 70,010 | 87,383 | 41,992 | 70,588 | 108,145 |

| MID CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 25,722 | 26,444 | 21,901 | 26,808 | 28,691 | 24,265 | 31,198 | 71,169 | 34,705 | 49,477 | 58,551 | 91,350 | 50,144 | 48,691 | 79,004 |
| Newfield Exploration | 37,356 | 28,416 | 26,076 | 25,815 | 35,486 | 26,346 | 31,901 | 30,871 | 41,569 | 65,300 | 63,310 | 75,629 | 48,734 | 78,142 | 92,087 |

| Canada<br>Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resource | NA | NA | NA | NA | 16,343 | 12,926 | 15,538 | 19,365 | 28,341 | 53,367 | 65,697 | 82,964 | 56,684 | 83,869 | 90,859 |
| Encana Corporation | NA | NA | NA | NA | NA | 25,679 | 40,127 | 37,540 | 43,621 | 59,099 | 58,745 | 82,351 | 56,130 | 55,673 | 51,699 |
| Nexen Inc | 15,122 | 19,236 | 9,993 | 15,762 | 16,436 | 13,049 | 15,110 | 23,112 | 34,487 | 64,147 | 116,311 | 103,451 | 60,636 | 82,847 | 73,452 |
| Talisman Energy | NA | 19,062 | 12,737 | 16,331 | 15,069 | 16,466 | 14,833 | 23,096 | 27,556 | 48,758 | 45,425 | 51,569 | 30,896 | 49,515 | 60,752 |

## Percentage Natural Gas Output

| US<br>LARGE CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 72% | 73% | 67% | 62% | 57% | 58% | 58% | 55% | 56% | 56% | 54% | 52% | 55% | 61% | 61% |
| Apache Corporation | 65% | 63% | 60% | 57% | 54% | 53% | 55% | 53% | 49% | 46% | 46% | 53% | 53% | 50% | 50% |
| Devon Energy | 61% | 56% | 57% | 62% | 63% | 59% | 61% | 68% | 63% | 59% | 61% | 67% | 64% | 66% | 69% |
| EOG Resources Inc | 86% | 86% | 86% | 85% | 85% | 83% | 84% | 85% | 86% | 84% | 85% | 86% | 85% | 81% | 78% |
| Murphy Oil Corporation | 43% | 41% | 44% | 40% | 38% | 37% | 41% | 43% | 33% | 22% | 14% | 15% | 16% | 7% | 17% |
| Noble Energy | 63% | 68% | 70% | 71% | 71% | 71% | 68% | 65% | 60% | 53% | 58% | 56% | 57% | 60% | 63% |
| Occidental Petroleum | 31% | 29% | 30% | 27% | 28% | 26% | 23% | 20% | 18% | 19% | 20% | 20% | 21% | 23% | 23% |
| Pioneer Natural Resources | 52% | 53% | 49% | 49% | 52% | 52% | 51% | 53% | 63% | 63% | 64% | 53% | 55% | 57% | 55% |

| MID CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 82% | 72% | 72% | 71% | 70% | 62% | 63% | 64% | 62% | 62% | 62% | 60% | 70% | 75% | 76% |
| Newfield Exploration | 73% | 73% | 72% | 75% | 77% | 75% | 76% | 79% | 83% | 81% | 79% | 82% | 80% | 73% | 69% |

| Canada<br>Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resources | 69% | 59% | 59% | 58% | 43% | 43% | 49% | 47% | 45% | 43% | 43% | 46% | 44% | 38% | 33% |
| Encana Corporation | 44% | 45% | 49% | 55% | 56% | 60% | 66% | 65% | 66% | 70% | 78% | 82% | 83% | 95% | 96% |
| Nexen Inc | 25% | 28% | 28% | 21% | 19% | 20% | 18% | 20% | 20% | 18% | 22% | 16% | 15% | 16% | 18% |
| Talisman Energy | 52% | 46% | 46% | 49% | 41% | 40% | 39% | 47% | 48% | 47% | 46% | 47% | 48% | 50% | 54% |

## Pricing

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NYMEX WTI | 25.92 | 17.64 | 12.05 | 25.60 | 26.80 | 19.84 | 31.20 | 32.52 | 43.45 | 61.04 | 61.05 | 95.98 | 44.60 | 61.08 | 79.81 |
| NYMEX HH | 2.76 | 2.26 | 1.95 | 2.33 | 9.78 | 2.57 | 4.79 | 6.19 | 6.15 | 11.23 | 6.30 | 7.48 | 5.62 | 4.24 | 4.46 |
| WTI/HH Price Ratio | 9.4 | 7.8 | 6.2 | 11.0 | 2.7 | 7.7 | 6.5 | 5.3 | 7.1 | 5.4 | 9.7 | 12.8 | 7.9 | 14.4 | 17.9 |

**Source: Company Reports, EIA, and SG Estimates**

### Conclusions

1. A more representative case since it includes net debt.
2. Some company valuations, given fiscal leverage are equal to fiscally underleveraged E&Ps, e.g., PXD (DTC of 38.6%) vs. OXY (DTC of 13.6%). As we'll show later, no differentiation for free cash flow.
3. As with market cap, investors now pay for oil leverage and liquids growth. And oil leveraged E&Ps don't get a proportionate premium vs. E&Ps that are natural gas leveraged.
4. So, investors don't fully differentiate, and again look at the marginal output changes.

## Enterprise Value vs. Proven Reserves

**This benchmark essentially addresses the 'in-ground' valuation for reserves since it compares enterprise value (market cap plus net debt) to proven reserves**. True, it doesn't incorporate '2P' (probable) or '3P' (possible) reserves as 'upside', but it is less subjective. Reserves used are net after royalties. We include the percentage of N.A. natural gas exposure to give a sense of how 'gas-affected' these stocks can be.

### Enterprise Value Per Proven Reserve

| US LARGE CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 7.60 | 6.47 | 5.46 | 5.81 | 10.50 | 8.34 | 7.47 | 7.12 | 7.76 | 10.10 | 14.16 | 18.19 | 12.01 | 17.13 | 19.14 |
| Apache Corporation | 8.67 | 8.16 | 6.23 | 7.54 | 9.98 | 6.71 | 7.53 | 9.33 | 9.83 | 11.61 | 11.10 | 16.32 | 11.62 | 15.94 | 14.61 |
| Devon Energy | 3.43 | 2.83 | 3.93 | 4.21 | 8.81 | 6.87 | 8.99 | 10.10 | 11.88 | 15.19 | 16.87 | 19.23 | 15.06 | 14.44 | 12.70 |
| EOG Resources Inc | 6.79 | 5.42 | 3.88 | 5.08 | 11.34 | 7.62 | 7.45 | 7.43 | 10.14 | 17.53 | 13.88 | 17.87 | 12.56 | 14.86 | 14.19 |
| Murphy Oil Corporation | 10.78 | 10.14 | 8.20 | 10.49 | 9.93 | 11.60 | 14.66 | 23.92 | 30.35 | 45.67 | 37.42 | 61.17 | 30.98 | 24.21 | 31.11 |
| Noble Energy | 11.26 | 6.87 | 6.59 | 5.08 | 7.81 | 6.10 | 6.74 | 7.46 | 8.27 | 11.16 | 12.10 | 16.94 | 11.20 | 16.44 | 15.03 |
| Occidental Petroleum | 9.20 | 11.52 | 8.85 | 9.17 | 5.78 | 5.40 | 6.47 | 8.03 | 9.96 | 11.93 | 14.81 | 22.13 | 16.65 | 20.95 | 24.47 |
| Pioneer Natural Resources | 4.65 | 6.31 | 4.42 | 4.31 | 5.56 | 5.31 | 6.27 | 6.77 | 7.29 | 8.75 | 6.98 | 8.81 | 4.91 | 9.05 | 12.26 |

| MID CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 8.68 | 9.38 | 6.83 | 9.01 | 10.38 | 7.39 | 7.90 | 11.34 | 12.27 | 15.27 | 13.33 | 17.70 | 9.75 | 11.47 | 15.92 |
| Newfield Exploration | 17.87 | 13.23 | 12.30 | 13.55 | 19.90 | 13.53 | 13.34 | 14.29 | 15.54 | 21.64 | 18.53 | 18.27 | 9.75 | 13.89 | 19.31 |

| Canada Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resources | NA | NA | NA | NA | 4.84 | 4.24 | 5.12 | 6.71 | 9.62 | 18.50 | 19.55 | 25.67 | 16.40 | 13.56 | 17.03 |
| Encana Corporation | NA | NA | NA | NA | NA | 7.83 | 9.53 | 10.34 | 14.71 | 14.68 | 13.17 | 19.08 | 13.24 | 14.49 | 12.32 |
| Nexen Inc | 9.42 | 9.68 | 5.32 | 9.00 | 9.57 | 7.46 | 8.31 | 14.64 | 19.58 | 39.28 | 20.08 | 23.22 | 13.77 | 19.15 | 17.42 |
| Talisman Energy | NA | 7.07 | 4.53 | 5.60 | 6.44 | 5.86 | 5.79 | 8.17 | 10.06 | 17.42 | 16.07 | 17.28 | 11.07 | 17.51 | 21.90 |

### N.A. Natural Gas Reserves as a Percentage of Total

| US LARGE CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 50% | 41% | 47% | 42% | 49% | 50% | 50% | 50% | 52% | 54% | 58% | 58% | 59% | 56% | 56% |
| Apache Corporation | 49% | 42% | 38% | 33% | 40% | 39% | 40% | 37% | 38% | 39% | 36% | 34% | 33% | 33% | 38% |
| Devon Energy | 41% | 48% | 47% | 44% | 46% | 52% | 60% | 57% | 59% | 57% | 64% | 63% | 72% | 60% | 60% |
| EOG Resources Inc | 77% | 71% | 57% | 60% | 62% | 63% | 60% | 63% | 65% | 69% | 70% | 70% | 71% | 73% | 65% |
| Murphy Oil Corporation | 43% | 37% | 36% | 33% | 35% | 32% | 26% | 24% | 16% | 15% | 11% | 9% | 10% | 8% | 15% |
| Noble Energy | 58% | 49% | 45% | 38% | 32% | 27% | 22% | 20% | 17% | 34% | 35% | 35% | 36% | 31% | 25% |
| Occidental Petroleum | 22% | 21% | 22% | 22% | 16% | 15% | 13% | 12% | 14% | 14% | 14% | 16% | 18% | 14% | 15% |
| Pioneer Natural Resources | 46% | 42% | 44% | 40% | 39% | 40% | 36% | 35% | 51% | 49% | 53% | 50% | 51% | 45% | 43% |

| MID CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 69% | 72% | 73% | 69% | 61% | 54% | 52% | 62% | 60% | 60% | 53% | 71% | 73% | 77% | 76% |
| Newfield Exploration | 75% | 78% | 82% | 74% | 76% | 77% | 81% | 83% | 69% | 66% | 68% | 73% | 72% | 72% | 67% |

| Canada Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resources | 38% | 48% | 43% | 37% | 31% | 32% | 32% | 31% | 29% | 29% | 32% | 30% | 30% | 14% | 18% |
| Encana Corporation | NA | NA | NA | 43% | 60% | 65% | 60% | 59% | 78% | 64% | 65% | 71% | 69% | 96% | 96% |
| Nexen Inc | 26% | 20% | 22% | 26% | 27% | 30% | 29% | 28% | 22% | 22% | 9% | 9% | 9% | 7% | 7% |
| Talisman Energy | 44% | 41% | 33% | 32% | 31% | 29% | 29% | 32% | 29% | 27% | 28% | 27% | 32% | 36% | 38% |

### Pricing

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NYMEX WTI | 25.92 | 17.64 | 12.05 | 25.60 | 26.80 | 19.84 | 31.20 | 32.52 | 43.45 | 61.04 | 61.05 | 95.98 | 44.60 | 61.08 | 79.81 |
| NYMEX HH | 2.76 | 2.26 | 1.95 | 2.33 | 9.78 | 2.57 | 4.79 | 6.19 | 6.15 | 11.23 | 6.30 | 7.48 | 5.62 | 4.24 | 4.46 |
| WTI/HH Price Ratio | 9.4 | 7.8 | 6.2 | 11.0 | 2.7 | 7.7 | 6.5 | 5.3 | 7.1 | 5.4 | 9.7 | 12.8 | 7.9 | 14.4 | 17.9 |

**Source: Company Reports, EIA, and SG Estimates**

## Conclusions for Enterprise Value per Proven Reserves

1. Over the last 15 years, the average valuation for proven reserves for our 14 stocks under coverage has risen 5.4%. For 10 years that amount is 7.3% and over the last 5 years 1.1%.
2. These ‘in-ground’ valuations reflect net reserve exposure (natural gas, balanced, or oil leverage), growth rate changes, and perhaps investor belief in the quality of the unbooked asset base or drilling program. Some E&Ps trade at real premiums i.e. MUR that, in our opinion, aren’t fully justified.
3. As with the flowing-barrel exercise, some E&Ps, which have changed their production mix, restructured or espoused a growth or exploration profile, have been treated more positively than others.
4. What is interesting if one looks at this data and then scans the next page is that investors don’t appear to penalize an E&P for carrying too many PUDs.

**PUD Creep**

PUDs are proven undeveloped reserves. They are the source of future production revenues and once converted, replace depleting producing reserves . Over the last two decades, PUDs for most E&Ps have doubled. In our view, there are many E&Ps which have been reasonably aggressive with such bookings.

We plan to address PUDs in a finding cost study we plan to undertake later this spring. Not all 10Ks or 40Fs have been released. Irrespective, if one looks at an E&P’s PUDs as a percentage of total proven reserves, one can see that many companies have very high PUD levels. Most of these PUDs are North American natural gas.

Again, if one looks at the ‘in-ground’ reserve valuation, it doesn’t appear to us that the market has taken into account the dramatic rise in estimated future production and development costs associated with the PUDs, which follow on the opposing page from the PUD data. So, the ‘in-ground’ valuation in the past reflected proven reserves which required less drilling and capex than today. This is what we called ‘conversion risk’ in our initial report published last November.

**World Wide PUDs as a % of Total Proven Reserves**

| Large Cap | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 37% | 45% | 53% | 52% | 29% | 35% | 33% | 31% | 36% | 38% | 34% | 33% | 30% | 30% | 31% |
| Apache Corporation | 17% | 21% | 32% | 24% | 27% | 25% | 28% | 29% | 33% | 30% | 32% | 31% | 28% | 31% | 33% |
| Devon Energy | 3% | 14% | 20% | 27% | 32% | 34% | 27% | 24% | 20% | 24% | 27% | 23% | 18% | 30% | 29% |
| EOG Resources | 7% | 7% | 19% | 32% | 35% | 26% | 29% | 33% | 25% | 28% | 30% | 23% | 24% | 46% | 48% |
| Murphy Oil | 41% | 40% | 36% | 41% | 41% | 50% | 47% | 40% | 50% | 42% | 55% | 47% | 42% | 23% | 24% |
| Noble Energy | 8% | 22% | 24% | 33% | 20% | 24% | 29% | 11% | 24% | 25% | 29% | 27% | 30% | 33% | 54% |
| Occidental Pet. | 30% | 30% | 19% | 26% | 20% | 21% | 21% | 21% | 22% | 26% | 22% | 20% | 26% | 23% | 25% |
| Pioneer Natural Resources` | 22% | 14% | 10% | 19% | 23% | 30% | 33% | 35% | 35% | 38% | 40% | 38% | 42% | 42% | 43% |

| Mid Cap | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 28% | 22% | 16% | 16% | 27% | 39% | 37% | 25% | 23% | 27% | 29% | 30% | 37% | 37% | 40% |
| Newfield Exploration | 16% | 20% | 7% | 13% | 18% | 7% | 7% | 13% | 25% | 32% | 35% | 37% | 38% | 47% | 42% |

| Canadian Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resources | 25% | 30% | 29% | 32% | 36% | 33% | 33% | 34% | 36% | 32% | 39% | 42% | 44% | 25% | 28% |
| Encana | 8% | 15% | 16% | 17% | 20% | 16% | 35% | 39% | 33% | 46% | 49% | 46% | 45% | 41% | 49% |
| Nexen | 16% | 19% | 20% | 25% | 21% | 24% | 21% | 22% | 37% | 42% | 29% | 31% | 44% | 45% | 51% |
| Talisman Energy | 22% | 22% | 26% | 17% | 22% | 28% | 24% | 22% | 28% | 30% | 30% | 26% | 30% | 28% | 32% |

Source: Company reports and SG estimates

**Estimated Development and Production Costs (US$ millions)**

| Large Cap | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 3,721 | 3,237 | 3,678 | 4,309 | 12,961 | 11,896 | 15,953 | 20,176 | 21,253 | 28,940 | 42,287 | 48,979 | 35,592 | 35,864 | 42,315 |
| Apache Corporation | 6,472 | 3,212 | 2,508 | 4,560 | 7,842 | 7,403 | 9,076 | 15,961 | 25,353 | 31,822 | 37,270 | 51,078 | 41,387 | 38,027 | 57,736 |
| Chesapeake Energy | 306 | 343 | 178 | 166 | 393 | 1,619 | 2,880 | 4,729 | 8,658 | 19,471 | 20,594 | 27,634 | 26,206 | 25,501 | 31,986 |
| Devon Energy | 1,126 | 1,507 | 1,328 | 4,596 | 8,596 | 9,542 | 11,129 | 19,925 | 23,724 | 30,865 | 37,926 | 44,600 | 38,365 | 42,977 | 49,324 |
| EOG Resources | 2,812 | 2,412 | 3,433 | 2,446 | 4,343 | 2,764 | 3,812 | 5,787 | 8,862 | 13,325 | 12,871 | 18,478 | 16,921 | 23,156 | 37,272 |
| Murphy Oil | 1,706 | 1,675 | 1,538 | 1,766 | 2,340 | 2,768 | 2,479 | 2,480 | 2,490 | 2,352 | 3,348 | 5,710 | 3,781 | 9,730 | 13,034 |
| Noble Energy | 2,439 | 2,370 | 1,378 | 2,120 | 2,394 | 2,504 | 2,889 | 2,882 | 2,870 | 8,798 | 9,202 | 11,906 | 10,079 | 12,210 | 15,279 |
| Occidental Pet. | 10,275 | 9,867 | 7,340 | 7,862 | 18,336 | 20,838 | 25,009 | 31,047 | 37,416 | 54,136 | 64,463 | 75,080 | 61,107 | 66,277 | 85,723 |
| Pioneer Natural Resources` | 2,534 | 4,088 | 2,964 | 3,537 | 5,970 | 4,568 | 6,189 | 8,055 | 11,003 | 15,156 | 15,179 | 19,107 | 16,784 | 17,472 | 24,310 |

| Mid Cap | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 427 | 468 | 534 | 623 | 1,769 | 1,438 | 2,104 | 2,117 | 2,384 | 3,452 | 3,405 | 4,997 | 5,694 | 4,214 | 5,209 |
| Newfield Exploration | 221 | 330 | 366 | 571 | 777 | 946 | 1,468 | 1,831 | 3,096 | 4,554 | 5,514 | 7,157 | 6,854 | 7,962 | 8,898 |

| Canadian Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resources | | | | 3,035 | 6,701 | 6,883 | 9,855 | 13,329 | 19,128 | 27,464 | 44,429 | 48,044 | 47,868 | 127,331 | NA |
| Encana | | | | | 7,234 | 5,600 | 21,045 | 19,863 | 19,890 | 32,887 | 38,664 | 48,072 | 44,123 | 19,652 | 28,080 |
| Nexen | 1,631 | 3,085 | 2,711 | 2,956 | 3,574 | 4,123 | 4,665 | 4,439 | 6,258 | 6,570 | 12,713 | 15,217 | 13,855 | 38,564 | 40,506 |
| Talisman Energy | 2,976 | 3,966 | 3,662 | 5,126 | 6,413 | 8,434 | 10,602 | 11,862 | 15,131 | 21,047 | 35,674 | 40,021 | 28,539 | 33,441 | 31,830 |

**Pricing**

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NYMEX WTI | 25.92 | 17.64 | 12.05 | 25.60 | 26.80 | 19.84 | 31.20 | 32.52 | 43.45 | 61.04 | 61.05 | 95.98 | 44.60 | 61.08 | 79.81 |
| NYMEX HH | 2.76 | 2.26 | 1.95 | 2.33 | 9.78 | 2.57 | 4.79 | 6.19 | 6.15 | 11.23 | 6.30 | 7.48 | 5.62 | 4.24 | 4.46 |
| WTI/HH Price Ratio | 9.4 | 7.8 | 6.2 | 11.0 | 2.7 | 7.7 | 6.5 | 5.3 | 7.1 | 5.4 | 9.7 | 12.8 | 7.9 | 14.4 | 17.9 |

Source: Company Reports, EIA, and SG Estimates

**Worldwide Proven Bcfe Reserves (MMBOE)**

| Large Cap | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 601 | 708 | 935 | 991 | 2,062 | 2,305 | 2,328 | 2,513 | 2,368 | 2,448 | 3,012 | 2,431 | 2,277 | 2,304 | 2,422 |
| Apache Corporation | 506 | 586 | 613 | 807 | 1,086 | 1,267 | 1,313 | 1,657 | 1,937 | 2,117 | 2,313 | 2,446 | 2,401 | 2,367 | 2,953 |
| Devon Energy | 368 | 477 | 514 | 1,056 | 1,097 | 1,620 | 1,609 | 2,089 | 2,077 | 2,111 | 2,149 | 2,376 | 2,299 | 2,733 | 2,873 |
| EOG Resources | 661 | 741 | 976 | 602 | 637 | 705 | 767 | 869 | 941 | 1,032 | 1,134 | 1,295 | 1,448 | 1,796 | 1,950 |
| Murphy Oil | 241 | 259 | 264 | 280 | 317 | 370 | 320 | 289 | 248 | 220 | 262 | 277 | 271 | 439 | 455 |
| Noble Energy | 308 | 378 | 323 | 333 | 395 | 463 | 468 | 457 | 525 | 806 | 835 | 880 | 864 | 820 | 1,092 |
| Occidental Petroleum | 1,328 | 1,310 | 1,424 | 1,352 | 2,171 | 2,242 | 2,312 | 2,470 | 2,532 | 2,707 | 2,831 | 2,865 | 2,977 | 3,226 | 3,363 |
| Pioneer Natural Resources | 302 | 762 | 677 | 605 | 628 | 671 | 737 | 789 | 1,022 | 987 | 905 | 964 | 960 | 899 | 1,011 |

| Mid Cap | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 80 | 88 | 129 | 120 | 230 | 258 | 260 | 216 | 222 | 245 | 243 | 353 | 445 | 353 | 374 |
| Newfield Exploration | 54 | 73 | 86 | 99 | 115 | 156 | 201 | 219 | 297 | 333 | 379 | 416 | 492 | 603 | 619 |

| Canadian Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resources | 408 | 559 | 605 | 796 | 1,031 | 1,092 | 1,279 | 1,320 | 1,514 | 1,592 | 1,949 | 1,969 | 1,960 | 3,557 | 3,369 |
| Encana | 749 | 883 | 842 | 890 | 988 | 952 | 2,114 | 2,359 | 2,245 | 3,085 | 3,203 | 3,144 | 3,285 | 1,920 | 2,309 |
| Nexen~ | 264 | 467 | 475 | 393 | 412 | 441 | 458 | 399 | 451 | 393 | 912 | 917 | 926 | 920 | 918 |
| Talisman Energy | 522 | 643 | 760 | 899 | 951 | 1,181 | 1,144 | 1,086 | 1,207 | 1,312 | 1,367 | 1,348 | 1,207 | 1,201 | 1,149 |

~restated 2006-2009

Source: Company reports and SG estimates

It's our observation that the estimated production and development costs calculated by the companies for their SEC PV10 have grown at a rate greater than the rate of proven reserves. Do investors adjust for potential conversion or timing risk of today's drilling programs which require thousands of $5-8MM unconventional wells? No.

For example, on a mid cap 4Q10 conference call this week, one manager said to look at the one half billion dollar reserve impairment as part of an in-kind asset exchange when they sold Barnett shale output and acreage for additional exposure to the Marcellus. What he didn't say was that those natural gas assets sold simply weren't economic. In today's world, we believe that E&Ps have traded reserve recognition risk for economic conversion risk which is generally skewed towards natural gas. But, given the pricing discrepancy, many E&Ps are now pursuing liquids (NGLs and oil) even though liquids-dominated upstream capex won't materially change output balance between oil and natural gas.

**Debt Adjusted Reserve Growth**

Management teams frequently talk about debt reserve growth. In the past, it may have been a reasonable relative benchmark, but EBITDAX/Net Interest expense ratios have risen on average from where they were in the 1990s given stronger petroleum prices (oil and natural gas) and the secular decline of interest rates. Most of the companies have much less fiscal leverage than in the past if one just looks at ratios of long-term debt to book capitalization or more importantly EBITDAX/Net Interest expense coverage. So, until interest rates approach non-Japanese levels in the US, we don't see the relevance. And we note that one company that always emphasized this metric recently sold equity (currently a higher cost of capital) because it was outspending its project cash flow by $2.9 billion. For many companies, the debt levels haven't gone down.

**Debt/Proved Reserves**

| US<br>LARGE CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | 1.22 | 1.35 | 1.52 | 1.46 | 1.93 | 2.19 | 2.35 | 2.01 | 1.62 | 1.50 | 7.63 | 6.07 | 5.42 | 5.53 | 5.37 |
| Apache Corporation | 2.45 | 2.59 | 2.22 | 2.34 | 2.04 | 1.77 | 1.64 | 1.40 | 1.34 | 1.04 | 1.65 | 1.73 | 2.05 | 2.14 | 2.76 |
| Devon Energy | 0.43 | 0.31 | 1.08 | 1.69 | 1.87 | 4.07 | 4.70 | 4.27 | 3.83 | 3.14 | 3.62 | 3.34 | 2.54 | 2.66 | 1.96 |
| EOG Resources Inc | 0.70 | 1.00 | 1.17 | 1.65 | 1.35 | 1.21 | 1.49 | 1.28 | 1.15 | 0.95 | 0.65 | 0.92 | 1.31 | 1.56 | 2.68 |
| Murphy Oil Corporation | 0.89 | 0.83 | 1.29 | 1.40 | 1.77 | 1.54 | 2.88 | 4.01 | 2.68 | 2.79 | 3.23 | 5.53 | 3.79 | 3.08 | 2.06 |
| Noble Energy | 2.75 | 1.71 | 2.31 | 1.41 | 1.33 | 1.91 | 2.18 | 2.03 | 1.68 | 2.52 | 2.16 | 2.13 | 2.62 | 2.48 | 2.08 |
| Occidental Petroleum | 3.61 | 3.97 | 4.79 | 3.63 | 2.74 | 2.06 | 2.03 | 1.82 | 1.51 | 1.09 | 0.99 | 0.63 | 0.93 | 0.87 | 1.52 |
| Pioneer Natural Resources | 1.08 | 2.56 | 3.21 | 2.88 | 2.51 | 2.35 | 2.26 | 1.97 | 2.33 | 2.09 | 1.65 | 2.86 | 3.09 | 3.07 | 2.57 |

| MID CAP E&P | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | 0.29 | 0.36 | 0.54 | 0.38 | 0.30 | 0.26 | 0.33 | 0.37 | 0.38 | 0.36 | 0.40 | 0.73 | 1.20 | 0.88 | 0.77 |
| Newfield Exploration | 0.12 | 0.22 | 0.34 | 0.33 | 0.26 | 0.45 | 0.66 | 0.39 | 0.51 | 0.41 | 0.51 | 0.43 | 0.92 | 0.86 | 0.78 |

| Canada<br>Seniors | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resource | 1.05 | 1.42 | 1.54 | 1.87 | 1.60 | 1.54 | 2.03 | 1.66 | 2.06 | 1.79 | 4.87 | 5.63 | 5.38 | 2.59 | NA |
| Encana Corporation | 0.87 | 0.93 | 1.07 | 0.86 | 0.88 | 1.50 | 2.55 | 2.70 | 3.53 | 2.20 | 2.13 | 3.04 | 2.74 | 4.05 | 3.30 |
| Nexen Inc | | 3.31 | 2.44 | 2.31 | 2.57 | 2.18 | 2.57 | 5.38 | 8.07 | 8.06 | 4.60 | 5.15 | 5.80 | 7.58 | 5.61 |
| Talisman Energy | 1.26 | 1.89 | 1.79 | 1.68 | 1.21 | 1.58 | 1.66 | 1.57 | 1.70 | 2.78 | 2.91 | 3.69 | 2.74 | 3.11 | 3.66 |

**Pricing**

| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NYMEX WTI | 25.92 | 17.64 | 12.05 | 25.60 | 26.80 | 19.84 | 31.20 | 32.52 | 43.45 | 61.04 | 61.05 | 95.98 | 44.60 | 61.08 | 79.81 |
| NYMEX HH | 2.76 | 2.26 | 1.95 | 2.33 | 9.78 | 2.57 | 4.79 | 6.19 | 6.15 | 11.23 | 6.30 | 7.48 | 5.62 | 4.24 | 4.46 |
| WTI/HH Price Ratio | 9.4 | 7.8 | 6.2 | 11.0 | 2.7 | 7.7 | 6.5 | 5.3 | 7.1 | 5.4 | 9.7 | 12.8 | 7.9 | 14.4 | 17.9 |

Source: Company Reports, EIA, and SG Estimates

**EBITDAX/Net Interest Expense**

| US<br>LARGE CAP E&P | 2010 | 2005 | 2000 |
|---|---|---|---|
| Anadarko Petroleum | 6.6 | 27.5 | 23.5 |
| Apache Corporation | 37.9 | 102.6 | 18.3 |
| Devon Energy | 17.2 | 14.0 | 13.6 |
| EOG Resources Inc | 19.1 | 42.4 | 17.3 |
| Murphy Oil Corporation | 58.7 | 212.3 | 52.6 |
| Noble Energy | 25.4 | 17.0 | 17.7 |
| Occidental Petroleum | 92.2 | 50.9 | 6.1 |
| Pioneer Natural Resources | 8.9 | 10.7 | 3.5 |

| MID CAP E&P | 2010 | 2005 | 2000 |
|---|---|---|---|
| Forest Oil | 4.0 | 12.4 | 7.5 |
| Newfield Exploration | 11.5 | 59.4 | 58.1 |

| Canadian Seniors | 2010 | 2005 | 2000 |
|---|---|---|---|
| Canadian Natural Resource | 16.4 | 46.5 | 13.3 |
| Encana Corporation | 11.5 | 16.1 | 28.3 |
| Nexen Inc | 11.1 | 24.1 | 15.0 |
| Talisman Energy | 27.8 | 37.2 | 22.6 |

Source: Company reports and SG estimates

**Conclusions from Flowing-Barrel, In-Ground Reserve Valuations and Debt/Proven Reserves**

1. The market now focuses much more on short-term relationships with the 'at the margin' commodity in favour, and that's reflected in changing benchmark levels.

2. Given above average natural gas production and reserve exposure for most N.A. E&Ps, the disparity between WTI and HH natural gas pricing naturally makes E&P management teams seek liquids growth. But, N.A. is a natural gas prone province and they will have to spend disproportionately for many years or restructure their asset bases (seek JVs , spin out or sell) in order to become more balanced. Certainly, over the last 15 years, they haven't been consistent or balanced.

**Why isn't there more Free Cash Flow: With $100+/Bbl oil and sub $4/Mcf gas?**

Right now our 2011 $85 WTI forecast doesn't look realistic, but our $4.15/Mcf market isn't far off the current NYMEX strip. Given announced 2011 capex budgets, we can now better address who will is likely to generate free cash flow (FCF = Operating Cash Flow – Capital Expenditure), and who is less likely to. It's really a short list in terms of meaningful generators: OXY, APA and CNQ. Other deficit spenders addressed their spending gaps i.e. EOG. One might ask why isn't there more? And the simple answer is that E&Ps are drilling the tight reservoir plays in sedimentary basins where costs aren't dropping. Lateral horizontal lengths and frac zones are increasing. So, drilling efficiencies may be up, but overall well costs continue to rise.

**Free Cash Flow (US$ millions)**

| US<br>LARGE CAP E&P | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko Petroleum | -83 | -113 | -324 | -677 | -362 | -172 | 5 | -192 | 271 | 143 | 738 | 326 | -1346 | 1641 | -426 | 239 |
| Apache Corporation | -818 | -161 | -61 | -228 | -1262 | -689 | -16 | 73 | -254 | -105 | 616 | -1286 | -130 | 1093 | 593 | 593 |
| Devon Energy | -56 | -12 | 38 | -184 | -109 | 339 | | -1672 | 1181 | 1713 | 1522 | -1558 | 493 | 33 | -142 | -998 |
| EOG Resources Inc | -110 | -174 | -95 | -287 | 39 | 365 | 223 | -46 | 116 | 28 | 645 | -241 | -786 | -562 | -581 | -2873 |
| Murphy Oil Corporation | 27 | 73 | -66 | -68 | -18 | 235 | -178 | -301 | -285 | 159 | -21 | -229 | -209 | 854 | -124 | 772 |
| Noble Energy | -16 | 123 | 119 | -107 | 201 | 33 | -103 | -86 | 75 | 54 | 459 | 528 | 604 | 22 | 240 | 61 |
| Occidental Petroleum | 522 | 802 | -152 | -994 | 443 | 1449 | 1251 | 864 | 1473 | 2035 | 2914 | 3348 | 3301 | 5988 | 2232 | 5409 |
| Pioneer Natural Resources | | 7 | -213 | -225 | 64 | 130 | -72 | -295 | 66 | 452 | 132 | -744 | -1429 | -419 | 80 | 89 |

| MID CAP E&P | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forest Oil | -30 | -41 | -96 | -285 | -15 | -83 | -71 | -168 | -204 | 248 | 134 | -494 | -112 | -1334 | -72 | -275 |
| Newfield Exploration | -40 | -32 | -83 | -172 | -15 | -39 | 1 | 90 | 132 | 138 | 55 | -322 | -1447 | -1456 | 169 | -341 |

| Canada<br>Seniors | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Canadian Natural Resources | -75 | -140 | -444 | -245 | -865 | 359 | -37 | 172 | 468 | -744 | -465 | -2655 | -654 | -539 | 2697 | 2697 |
| Encana Corporation | -105 | -13 | -271 | -98 | 152 | 541 | 519 | -1500 | -804 | -226 | 505 | 1373 | -308 | 601 | 3009 | -2408 |
| Nexen Inc | 196 | 162 | -34 | -165 | 72 | 276 | 101 | -192 | -19 | -62 | -424 | -822 | -579 | 1043 | -1537 | -255 |
| Talisman Energy | 3 | -36 | -236 | -470 | -388 | 738 | 170 | 203 | -204 | 210 | 960 | -174 | -365 | 906 | -459 | -578 |

Note: Free Cash Flow calculated as Operating Cash Flow - Capital Expenditures

**Source: FactSet, Compustat**

# Report Summary

Over the last two decades, most E&Ps grew via corporate M&A and proven producing property purchases (some 24% vs. 12% for exploration). By and large, E&Ps experienced substantial reserve and corresponding production growth, but they recognized technical limits of their exploration portfolio or political risks and opted to emphasize domestic or N.A. exploitation. Others persevered and didn't alter their upstream strategies significantly.

The N.A. E&P landscape has changed because of tight reservoir exploitation technologies and conventional exploration risk aversion. The US may be well oversupplied with natural gas until the upstream companies reduce natural gas capex or demand growth materializes that is sustained, and not a 'one-off' like coal displacement.

Longer term, the industry may have to pursue multi-year sales contracts as it did during the 1970s and 1980s. N.A. natural gas prices are $1.50 under levels of one year ago. WTI prices are $40/Bbl higher, but we don't think they'll be sustained given the potential for demand erosion.

Investors never pay fully for commodity pricing change. Currently, underweighted investors are seeking 'safer equity havens' by moving into the large cap E&Ps with oil leverage or the integrateds. Most E&Ps have oil exposure in OECD rather than non-OECD markets, but some stocks are bought that have higher PSC exposure, e.g., MUR which won't get the full Brent uplift.

We now believe that investors should be market weight the group and remain underweight the natural gas leveraged E&Ps because we think it's just too early to make that call. EIA 914 data shows growing natural gas supply as does our annual summary on the next page. Looking at 2010, averaging the companies that have reported, US natural gas output is up over 3%. And even with liquids emphasis, the number of wells in need of completion will add enough supplies with current activity. The risk to that view is that weather gets very hot to consume natural gas in peaking situations or the government mandates more natural gas use. We expect 2011 prices to remain near $4, which is why the WTI/HH price ratio is so high.

## US Dry Natural Gas Production (MMcf/d)*

| Integrateds | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | YOY | CAGR5 | CAGR10 | CAGR15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BP | 4,228 | 4,020 | 3,703 | 3,446 | 3,502 | 3,510 | 3,711 | 3,564 | 3,578 | 3,667 | 3,413 | 3,554 | 3,484 | 3,130 | 2,749 | 2,548 | 2,377 | 2,119 | 2,116 | 2,258 | 2,184 | -3% | -2% | -5% | -10% |
| Chevron | 4,658 | 4,293 | 4,102 | 3,785 | 3,799 | 3,472 | 3,550 | 3,555 | 3,419 | 3,101 | 2,868 | 2,708 | 2,407 | 2,229 | 1,873 | 1,565 | 1,695 | 1,589 | 1,398 | 1,303 | 1,252 | -4% | -6% | -7% | -19% |
| ConocoPhillips | 1,579 | 1,709 | 1,780 | 1,808 | 1,906 | 1,819 | 1,840 | 1,748 | 1,855 | 1,831 | 1,584 | 1,551 | 1,408 | 1,296 | 1,223 | 1,188 | 2,028 | 2,182 | 1,994 | 1,927 | 1,695 | -12% | -4% | 1% | -2% |
| Hess Corp | 457 | 584 | 602 | 503 | 428 | 402 | 338 | 312 | 294 | 338 | 288 | 424 | 373 | 253 | 171 | 137 | 110 | 88 | 78 | 93 | 108 | 16% | 0% | -13% | -20% |
| Exxon Mobil | 3,395 | 3,358 | 3,248 | 3,285 | 3,590 | 3,499 | 3,426 | 3,231 | 3,147 | 2,871 | 2,856 | 2,599 | 2,376 | 2,209 | 1,931 | 1,739 | 1,625 | 1,468 | 1,246 | 1,275 | 2,596 | 104% | 10% | 0% | -5% |
| Marathon | 795 | 689 | 593 | 529 | 574 | 634 | 676 | 571 | 600 | 755 | 571 | 614 | 578 | 566 | 457 | 411 | 376 | 335 | 322 | 286 | 260 | -9% | -7% | -8% | -17% |
| Royal Dutch/Shell | 1,350 | 1,335 | 1,361 | 1,564 | 1,676 | 1,906 | 1,860 | 1,920 | 1,893 | 1,848 | 1,644 | 1,598 | 1,679 | 1,528 | 1,332 | 1,146 | 1,163 | 1,130 | 1,053 | 1,061 | 1,153 | 9% | 0% | -3% | -9% |
| **Sub-Total** | **16,461** | **15,988** | **15,388** | **14,920** | **15,475** | **15,241** | **15,400** | **14,901** | **14,785** | **14,412** | **13,223** | **13,048** | **12,303** | **11,210** | **9,737** | **8,734** | **9,374** | **8,911** | **8,207** | **8,203** | **9,248** | **13%** | **0%** | **-3%** | **-10%** |
| **U.S. Independents- Large** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Anadarko Petroleum | 967 | 913 | 974 | 1,062 | 1,236 | 1,386 | 1,432 | 1,592 | 1,637 | 1,459 | 1,171 | 1,569 | 1,390 | 1,378 | 1,363 | 1,135 | 1,529 | 1,912 | 2,049 | 2,217 | 2,272 | 2% | 8% | 4% | 10% |
| Apache Corp. | 259 | 287 | 265 | 303 | 437 | 485 | 472 | 493 | 432 | 464 | 544 | 615 | 504 | 665 | 647 | 598 | 667 | 770 | 680 | 666 | 731 | 10% | 2% | 2% | 9% |
| Chesapeake Energy | | | | | | 69 | 142 | 170 | 259 | 265 | 283 | 370 | 440 | 659 | 880 | 1,157 | 1,442 | 1,957 | 2,120 | 2,287 | 2,534 | 11% | 12% | 21% | 78% |
| Devon Energy | 263 | 280 | 339 | 439 | 439 | 438 | 448 | 534 | 557 | 863 | 1,252 | 1,391 | 1,344 | 1,716 | 1,651 | 1,522 | 1,551 | 1,739 | 1,983 | 2,037 | 1,960 | -4% | 5% | 3% | 34% |
| EOG Resources | 438 | 466 | 530 | 649 | 614 | 560 | 608 | 657 | 671 | 655 | 654 | 681 | 635 | 639 | 632 | 717 | 817 | 971 | 1,162 | 1,134 | 1,133 | 0% | 7% | 5% | 13% |
| Murphy | 195 | 151 | 188 | 215 | 196 | 189 | 155 | 206 | 170 | 172 | 145 | 115 | 91 | 82 | 94 | 70 | 57 | 45 | 46 | 54 | 53 | -2% | -1% | -7% | -19% |
| Noble Energy | 158 | 178 | 203 | 211 | 248 | 270 | 465 | 566 | 544 | 422 | 378 | 379 | 328 | 276 | 244 | 343 | 452 | 412 | 365 | 397 | 400 | 1% | -2% | 1% | -3% |
| Occidental Petroleum | 641 | 634 | 619 | 601 | 621 | 612 | 601 | 596 | 614 | 661 | 660 | 610 | 565 | 532 | 507 | 545 | 588 | 593 | 587 | 635 | 677 | 7% | 3% | 1% | 2% |
| Pioneer Natural Res. | 408 | 350 | 309 | 330 | 444 | 447 | 440 | 389 | 378 | 291 | 229 | 213 | 232 | 445 | 539 | 499 | 285 | 316 | 367 | 353 | 336 | -5% | 3% | 5% | -5% |
| XTO Energy^ | - | 49 | 51 | 51 | 58 | 78 | 102 | 136 | 229 | 288 | 344 | 417 | 514 | 668 | 835 | 1,033 | 1,186 | 1,458 | 2,335 | 2,342 | 1,178 | -50% | 0% | 11% | 63% |
| **Sub-Total** | **5,925** | **6,011** | **6,282** | **6,763** | **7,532** | **7,855** | **8,106** | **8,531** | **8,543** | **8,426** | **8,468** | **8,883** | **8,329** | **9,140** | **9,569** | **9,531** | **8,574** | **10,174** | **11,693** | **12,123** | **11,273** | **-7%** | **6%** | **2%** | **7%** |
| **U.S. Independents- Mid** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Cabot Oil & Gas | 109 | 120 | 124 | 127 | 160 | 159 | 161 | 175 | 176 | 180 | 166 | 189 | 202 | 197 | 199 | 199 | 211 | 210 | 236 | 266 | 344 | 29% | 10% | 6% | 16% |
| Cimarex Energy | | | | | | | | | | | | 115 | 113 | 138 | 174 | 275 | 342 | 327 | 348 | 323 | 364 | 13% | 1% | 12% | |
| Continental Resources | | | | | | | | | | | | | | 29 | 24 | 25 | 25 | 34 | 43 | 59 | 66 | 11% | 21% | | |
| Concho Resources | | | | | | | | | | | | | | | 1 | 9 | 26 | 32 | 41 | 59 | 86 | 46% | 27% | | |
| Denbury Resources | | | | | 9 | 13 | 24 | 36 | 37 | 28 | 37 | 85 | 100 | 95 | 82 | 59 | 83 | 97 | 89 | 68 | 78 | 15% | -1% | -1% | 26% |
| Exco Resources | | | | | | | | | | | | | | 21 | 52 | 56 | 121 | 305 | 359 | 325 | 296 | -9% | 20% | | |
| Forest Oil | 81 | 62 | 51 | 136 | 88 | 91 | 78 | 93 | 130 | 135 | 280 | 267 | 215 | 231 | 250 | 227 | 200 | 227 | 323 | 318 | 278 | -13% | 7% | 0% | 29% |
| Petrohawk | | | | | | | | | | 1 | 5 | 7 | 5 | 5 | 10 | 55 | 174 | 273 | 280 | 477 | 643 | 35% | 30% | NM | |
| Newfield Exploration | | 15 | 44 | 62 | 66 | 92 | 113 | 146 | 182 | 239 | 288 | 365 | 396 | 505 | 548 | 523 | 545 | 507 | 460 | 477 | 537 | 13% | 0% | 4% | 37% |
| Plains Petroleum | | | | 11 | 10 | 8 | 6 | 8 | 8 | 9 | 8 | 9 | 9 | 50 | 106 | 80 | 57 | 80 | 217 | 208 | 255 | 23% | 35% | 39% | 113% |
| QEP Resources | | | | | | | | 121 | 133 | 164 | 169 | 175 | 205 | 216 | 246 | 274 | 312 | 334 | 417 | 462 | 558 | 21% | 12% | 12% | |
| Range Resources | | | | 7 | 19 | 34 | 58 | 105 | 124 | 139 | 112 | 116 | 113 | 119 | 139 | 173 | 206 | 246 | 312 | 358 | 389 | 9% | 14% | 13% | 46% |
| Southwestern Energy | | 56 | 71 | 98 | 103 | 95 | 95 | 91 | 90 | 81 | 87 | 97 | 99 | 104 | 138 | 156 | 187 | 301 | 527 | 821 | 1,106 | 35% | 43% | 28% | 63% |
| Ultra Petroleum | | | | | | | | | 11 | 5 | 15 | 32 | 45 | 76 | 120 | 169 | 215 | 299 | 380 | 472 | 563 | 19% | 21% | 33% | |
| Whiting Petroleum | | | | | | | | | | | 46 | 55 | 59 | 59 | 68 | 83 | 88 | 88 | 82 | 83 | 75 | -10% | -3% | 3% | |
| **Sub-total** | **322** | **387** | **435** | **594** | **679** | **696** | **732** | **1,023** | **1,168** | **1,240** | **1,492** | **1,876** | **1,964** | **2,265** | **2,636** | **2,770** | **2,994** | **3,361** | **4,115** | **4,776** | **5,637** | **18%** | **13%** | **12%** | **50%** |
| **U.S. Independents- Small** | | | | | | | | | | | | | | | | | | | | | | | | | |
| ATP | | | | | | | | | | 45 | 61 | 57 | 49 | 30 | 37 | 40 | 53 | 68 | 46 | 33 | | -100% | -100% | -100% | |
| Bill Barrett | | | | | | | | | | | | | 17 | 45 | 79 | 99 | 131 | 158 | 202 | 234 | 246 | 5% | 13% | | |
| Berry Petroleum | | | | | | 2 | 1 | 1 | 1 | 0 | 1 | 1 | 2 | 3 | 8 | 23 | 34 | 43 | 70 | 62 | 66 | 6% | 14% | NM | NM |
| Comstock | | 2 | 12 | 23 | 18 | 26 | 53 | 63 | 73 | 65 | 73 | 76 | 91 | 94 | 92 | 79 | 83 | 107 | 147 | 167 | 189 | 13% | 18% | 9% | 29% |
| Carizzo | | | | | | | | | | 9 | 15 | 12 | 13 | 13 | 18 | 22 | 28 | 44 | 67 | 88 | | -100% | -100% | -100% | |
| Energy Partners | | | | | | | | | 1 | 2 | 16 | 35 | 54 | 79 | 82 | 88 | 106 | 92 | 45 | 57 | 43 | -25% | -17% | 2% | |
| Goodrich Petroleum | | | | | | | | | | | | 10 | 7 | 9 | 13 | 17 | 36 | 42 | 63 | 79 | 90 | 14% | 20% | 24% | |
| Quicksilver Resources | | | | | | | | | 40 | 44 | 73 | 87 | 87 | 87 | 84 | 87 | 96 | 106 | 123 | 168 | 226 | 34% | 19% | 10% | |
| Mariner Energy | | | | 34 | 39 | 37 | 56 | 49 | 53 | 58 | 70 | 52 | 81 | 65 | 65 | 50 | 154 | 188 | 219 | 249 | 106 | -57% | -7% | 8% | 14% |
| McMoran | | | | | | | | | | | | | 13 | 6 | 5 | 22 | 40 | 116 | 164 | 137 | 104 | -24% | 21% | | |
| Oasis Petroleum | | | | | | | | | | | | | | | | | | 0 | 0 | 1 | | -100% | #NUM! | | |
| Penn Virginia | | | 7 | 15 | 17 | 20 | 21 | 21 | 22 | 24 | 32 | 36 | 51 | 55 | 60 | 70 | 79 | 104 | 114 | 119 | 107 | -10% | 6% | 11% | 39% |
| SM Energy | 28 | 29 | 32 | 31 | 34 | 34 | 43 | 63 | 70 | 62 | 105 | 108 | 105 | 136 | 128 | 142 | 155 | 181 | 205 | 195 | 197 | 1% | 5% | 6% | 36% |
| Sand Ridge | | | | | | | | | | | | | | | 37 | 19 | 37 | 142 | 239 | 240 | 209 | -13% | 42% | | |
| Stone Energy | | | | | | 58 | 43 | 68 | 139 | 180 | 197 | 187 | 184 | 174 | 152 | 148 | 119 | 124 | 94 | 113 | 115 | 2% | -1% | -5% | 22% |
| Swift Energy | | | | | 19 | 22 | 43 | 56 | 75 | 73 | 75 | 72 | 74 | 77 | 65 | 65 | 62 | 46 | 56 | 58 | 54 | -7% | -3% | -3% | 5% |
| W&T Offshore | | | | | | | | | | | 34 | 78 | 108 | 145 | 146 | 128 | 165 | 210 | 154 | 141 | 122 | -13% | -6% | 5% | |
| **Sub-Total** | **28** | **31** | **52** | **164** | **189** | **255** | **345** | **458** | **642** | **754** | **966** | **1,050** | **1,203** | **1,290** | **1,387** | **1,389** | **1,606** | **1,771** | **2,008** | **2,141** | **1,874** | -12% | 3% | 6% | 40% |
| **Total US Company Production** | **22,735** | **22,417** | **22,157** | **22,441** | **23,875** | **24,047** | **24,583** | **24,913** | **25,138** | **24,832** | **24,149** | **24,857** | **23,799** | **23,906** | **23,329** | **22,423** | **22,546** | **24,216** | **26,024** | **27,243** | **28,032** | 3% | 4% | 1% | 3% |
| **Canadian Seniors** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Encana | | | | | | | | | | | 68 | 279 | 500 | 589 | 871 | 1,096 | 1,182 | 1,345 | 1,633 | 1,616 | 1,861 | 15% | 10% | 21% | |
| Nexen | | | | | 66 | 54 | 78 | 78 | 95 | 117 | 113 | 121 | 93 | 122 | 126 | 99 | 93 | 85 | 66 | 57 | 93 | 63% | 0% | -3% | 4% |
| Talisman | | | | | | | | | | | | | | | | | | 73 | 63 | 72 | 189 | 163% | | | |
| | **0** | **0** | **0** | **0** | **66** | **54** | **78** | **78** | **95** | **117** | **181** | **400** | **593** | **711** | **997** | **1,195** | **1,275** | **1,503** | **1,761** | **1,745** | **2,143** | | 11% | 18% | 94% |
| **US Gas Production (Bcf/d)** | **48.8** | **48.5** | **48.9** | **49.6** | **51.6** | **51.0** | **51.7** | **51.8** | **52.1** | **51.6** | **52.6** | **53.7** | **51.9** | **52.3** | **50.9** | **49.5** | **50.7** | **52.8** | **55.2** | **56.4** | **59.1** | 5% | 3% | 1% | 3% |
| **Canadian Imports** | **4.0** | **4.7** | **5.7** | **6.2** | **7.0** | **7.7** | **7.9** | **7.9** | **8.4** | **9.2** | **9.7** | **10.2** | **10.4** | **9.4** | **9.9** | **10.1** | **9.8** | **10.4** | **9.8** | **9.0** | **8.8** | -1% | -2% | -1% | 2% |
| **BHI Natural Gas Rig Count** | **463** | **351** | **338** | **364** | **427** | **385** | **465** | **564** | **571** | **496** | **720** | **939** | **691** | **889** | **1,025** | **1,186** | **1,372** | **1,466** | **1,491** | **816** | **940** | 15% | -7% | 0% | 15% |
| **% Natural Gas Breakdown** | **1990** | **1991** | **1992** | **1993** | **1994** | **1995** | **1996** | **1997** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | | | | |
| % Integrated | 34% | 33% | 31% | 30% | 30% | 30% | 30% | 29% | 28% | 28% | 25% | 24% | 24% | 21% | 19% | 18% | 18% | 17% | 15% | 15% | 16% | 8% | -3% | -4% | -12% |
| % US Independent LC | 12% | 12% | 13% | 14% | 15% | 15% | 16% | 16% | 16% | 16% | 16% | 17% | 16% | 17% | 19% | 19% | 17% | 19% | 21% | 22% | 19% | -11% | 2% | 1% | 4% |
| % US Independent Mid | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 2% | 2% | 2% | 3% | 3% | 4% | 4% | 5% | 6% | 6% | 6% | 7% | 8% | 10% | 13% | 10% | 11% | 46% |
| % US Independent SC | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 1% | 1% | 1% | 2% | 2% | 2% | 2% | 3% | 3% | 3% | 3% | 4% | 4% | 3% | -16% | 0% | 5% | 37% |
| % Canadian Senior | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 1% | 2% | 2% | 3% | 3% | 3% | 3% | 4% | 17% | 8% | 17% | 89% |
| **Total** | 47% | 46% | 45% | 45% | 46% | 47% | 48% | 48% | 48% | 48% | 46% | 46% | 46% | 46% | 46% | 45% | 44% | 46% | 47% | 48% | 47% | -2% | 1% | 0% | 0% |

Source: Company reports and Societe Generale estimates  Rig count: BHI  #s include retired E&Ps not depicted  Marathon includes Alaska production prior to 1997.  * Data prior to 2001 includes ngls.

*Predessor E&Ps hidden or merged w/ purchasers. Lower 48 States. When possible, Alaska excluded

## Valuation and Risk Disclosures

| Large Cap US | Rating | Ticker | 03/07/2011 Price | 52 Week High | 52 Week Low | Target Price |
|---|---|---|---|---|---|---|
| Anadarko Petroleum | SELL | **APC** | 79.95 | 82.92 | 34.54 | $61.00 |
| Apache Corporation | HOLD | **APA** | 120.97 | 127.73 | 81.94 | $110.00 |
| Devon Energy | HOLD | **DVN** | 90.53 | 92.10 | 58.58 | $77.00 |
| EOG Resources | HOLD | **EOG** | 108.58 | 115.17 | 85.42 | $95.00 |
| Murphy Oil | SELL | **MUR** | 73.44 | 76.74 | 48.14 | $63.00 |
| Noble Energy | BUY | **NBL** | 93.47 | 95.00 | 56.23 | $96.00 |
| Occidental Petroleum | BUY | **OXY** | 103.53 | 107.56 | 72.13 | $99.00 |
| Pioneer Natural Resources | HOLD | **PXD** | 99.28 | 103.66 | 48.07 | $79.00 |
| **Mid Cap US** | | | | | | |
| Forest Oil | HOLD | **FST** | 33.71 | 40.23 | 22.85 | $30.00 |
| Newfield Exploration | HOLD | **NFX** | 72.01 | 76.55 | 44.81 | $64.00 |
| **Canadian Seniors** | | | | | | |
| Canadian Natural Resources (C$) | BUY | **CNQ** | 49.48 | 52.04 | 30.00 | 50.00 |
| Encana (US$) | HOLD | **ECA** | 32.12 | 35.25 | 26.02 | 26.00 |
| Nexen (C$) | HOLD | **NXY** | 27.02 | 27.94 | 17.20 | 23.00 |
| Talisman Energy (C$) | HOLD | **TLM** | 24.21 | 25.21 | 14.70 | 20.00 |

**Source: Company reports and SG estimates**

### Anadarko Petroleum (APC, Sell, $79.95)

Although we view the management team and the company's assets to be high quality, we don't think the Street has fully discounted the significant capital commitment associated with its future growth, the Macondo (GOM) liability or the potential liability associated with Tronox from its acquisition of Kerr-McGee. The stock has risen since YE coinciding with takeover speculation. Given its above-average risk profile, we use a 4.7x 2011 P/DCFPS multiple (25% discount to the LC peer group average of 6.3x consistent with our Sell-rated stocks) and an additional $5/share to reflect the risked resources contribution from projects beyond the 'Big Three' to arrive at our target price of $61/share. **Risks:** To refute our thesis, the upside risks would require the following: an M&A bid, BP being found grossly negligent, or a run-up in commodity prices.

### Apache (APA, Hold, $120.97)

Historically, APA shares have traded at a 10-20% discount to the peer group. Price targets on our Hold rated stocks reflect potential upside/downside risk relative to the peer group taking into account recent stock appreciation, relative operational and financial performance, and current valuation multiples relative to a stock's historical range. The stock is not expensive, but we believe it will be discounted based on its GOM exposure (19% of post purchase production). Given our belief in a 20% discount to the LC peer group average of 6.3x 2011 DCFPS, we think APC stock will trade to $110/share over the next 12 months, which we consider a Hold. **Risks** Lower wellhead price realizations or greater upstream operations costs, and international project timing in Australia, utilizations rates in the North Sea, and the absorption of the BP, DVN, and ME assets.

## Canadian Natural Resources (CNQ, Buy, C$48.10)

With our Buy recommendations, we use a 25% premium to the peer group multiple, consistent with the high end of the group's historical trading range. Our C$50/share price target reflects a 7.9x P/DCFPS multiple on our 2011 DCFPS estimate of C$6.54. **Risks** Lower wellhead price realizations or wider geographic sales basis differentials, reduced Horizon utilization rates post fire, greater upstream operating costs, or the timing of international project developments in West Africa could negatively affect bottom-line results, and our price target.

## Devon Energy (DVN, Hold, $90.53)

Price targets on our Hold rated stocks reflect potential upside/downside risk relative to the peer group taking into account recent price activity, relative operational and financial performance, and current valuation multiples relative to a stock's historical range. Given its natural gas leverage, we believe DVN should trade at the peer group average. Assigning the 2011 P/DCFPS peer group multiple of 6.3x, we arrive at a price target $77/share. **Risks** Given our guarded stance, the risk may be to the upside if N.A., natural gas prices improve or perception on the U.S. economy improves, but with the cash position and common stock buyback, we don't see much stock price downside potential.

## Encana Corporation (ECA, Hold, C$31.26)

Price targets on our Hold rated stocks reflect potential upside/downside risk relative to the peer group taking into account recent price activity, relative operational and financial performance, and current valuation multiples relative to a stock's historical range. Although we are negative on ECA's prospects, we recognize that the shares are widely held both north and south of the '49 degree parallel' and that the firm is reasonably hedged going into 2011 (34% natural gas production in our model), giving the stock somewhat of a valuation floor. Thus, our C$26/share price target reflects a more modest 10% discount to the peer group average of 6.3x 2011 P/DCFPS. **Risks** With a more wintery near term outlook, E&P stocks tend to 'chill up' as investor hope for cold and that is the main risk to having a neutral view. To the downside, it's simply lower natural gas pricing.

## EOG Resources (EOG, Hold, $108.58)

EOG has typically traded at a premium to peers because it has always espoused a value and volume growth story emphasizing ROCE. That strategy worked until U.S. natural gas prices decoupled from oil given the rise of the shale plays. Though an active shale participant and advocate of fraced horizontal wells, EOG, ever the price optimist, didn't hedge gas to the same extent as its peers, even when in a manufacturing mode. As a consequence, it is opting to add oil, but in doing so, will achieve volume growth via deficit spending. A $1bn sale of assets is planned, but N.A. gas prices are weak. Our $95/share price target thus reflects a modest 10% premium to the 2011 P/DCFPS LC peer group average of 6.3x. **Risks:** Lower natural gas prices could reduce cash flows further and cause more spending deficits or curtail projected growth rates.

## Forest Oil (FST, Hold, $33.71)

Price targets on our Hold rated stocks reflect potential upside/downside risk relative to the peer group taking into account recent price activity, relative operational and financial performance, and current valuation multiples relative to a stock's historical range. Our $30/share price target reflects a peer group average of 6.8x 2011 TC/EBITDA multiple plus $3.50/share of resource value ascribed to its Granite Wash and Eagle Ford plays. **Risks** Lower natural gas prices could reduce cash flows further and cause more spending deficits or curtail projected production growth rates. Higher NGL production (15% of total 2011 production) may lead to ethane rejection, widening the spread between NGLs and crude and cause lower netbacks.

## Murphy Oil (MUR, Sell, $73.44)

With our Sell rated stocks, we are using a 25% discount to the peer group average, consistent with the low end of the historical trading range. Our price target of $63/share reflects a 4.7x P/DCFPS (25% discount to the peer group) with $4/share added back to reflect a probability weighted monetization of the refining and UK marketing assets. **Risks** to our Sell rating MUR could have production growth that exceeds Street expectations, headline risk associated with drilling program success, and above average proceeds from its downstream asset sales.

## Newfield Exploration (NFX, Hold, $72.01)

Price targets on our Hold rated stocks reflect potential upside/downside risk relative to the peer group taking into account recent price activity, relative operational and financial performance, and current valuation multiples relative to a stock's historical range. One could argue given its 21% 2010 volume growth that such a premium is justified, but we think the hedged exposure, volume growth and unconventional assets are already discounted by the Street. Our $64/share price target reflects a 6.8x 2011 TC/EBITDAX multiple, a 10% premium to its historical average. **Risks** Lower natural gas prices, higher oilfield services costs and/or project timing could be negatives.

## Noble Energy (NBL, Buy, $93.47)

NBL remains one of the few LC E&Ps that pursues differential exploration optionality. Although the stock has recovered significantly from this summer's Macondo pullback, we believe there remains additional upside if the Israeli discoveries are brought to production cost effectively. Like our other Buys, we believe NBL should trade at a 25% premium to the peer group multiple, consistent with the high end of the group's historical trading range. To arrive at our $96 PT, we use a 25% premium to the LC peer group multiple or 7.9x our 2011 P/DCFPS plus $4.50/share from a risked valuation of the Leviathan project and the emerging Niobrara development, which we don't think is fully reflected in the current share price. **Risks:** The primary risk is uncertainty surrounding the degree of government take from its Israeli projects Leviathan and Tamar (although Tamar may be 'grandfathered'). Additional risks include volatility in commodity prices and cost escalation related to its field development both onshore and offshore.

## Nexen, Inc.  (NXY, Hold, C$26.23)

Price targets on our Hold rated stocks reflect upside/downside risk relative to the peer group taking into account recent price activity, relative operational and financial performance, and current valuation multiples relative to a stock's historical range. NXY has issues that cloud an improving upstream portfolio, including concerns over the steam-oil ratio (SOR) at Long Lake, re-negotiations in Yemen, and energizing a GoM program post Macondo. Our price target of C$23/share reflects a 20% discount to the peer group multiple or 5.0x 2011 P/DCFPS. **Risks** Ongoing SOR problems at Long Lake, a more protracted delineation for Knotty Head in the GoM or PSC negotiations in Yemen or higher operating costs could negatively affect NXY.

## Occidental Petroleum (OXY, Buy, $103.53)

With our Buy ratings, we are using a 25% premium to the peer group average, consistent with the high end of the group's historical trading range. Our $99/share price target reflects a 25% premium to the LC peer group multiple or 7.9x P/DCFPS plus $13.50/share of risked resource value from a combination of conventional and shale development opportunities in CA. **Risks** Lower oil prices, changing PSC terms, higher oilfield services costs could be bottom-line negatives.

## Pioneer Natural Resources (PXD, Hold, $99.28)

PXD has benefited from early Street recognition for its 'liquids' exposure, with the stock up 80% in 2010 vs 13% for the S&P500 over the same time frame. Our view is that PXD will require higher oil prices than we have modelled for 2011, in order to maintain its outperformance vs the peer group and the market. Given its higher debt load, we consider TC/EBITDAX to be the appropriate relative valuation benchmark. Our $79/share target price reflects a 7.1x 2011 TC/EBITDAX multiple, a 15% premium to the LC peer group average. **Risks** PXD's Eagle Ford or Spraberry/Wolfberry development programmes could surprise on the upside, oil prices could become triple digit to cause PXD's stock to continue to outperform. On the downside, there's program execution and cost control concerns.

## Talisman Energy (TLM, Hold, C$23.55)

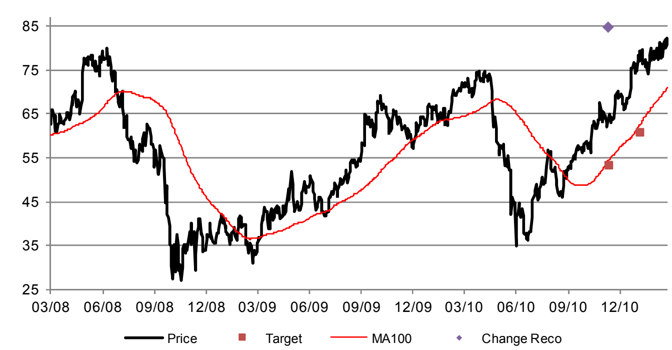
Price targets on our Hold rated stocks reflect potential upside/downside risk relative to the peer group taking into account recent price activity, relative operational and financial performance, and current valuation multiples relative to a stock's historical range. Historically, TLM has traded at a discount on a cash flow due in large part to the difficulty in predicting at the margin activity and related margins, natural gas leverage, price and FX exposure due to the geographic and product mix. Thus, we think a 15% discount to the peer group multiple is warranted. Our C$20/share price target reflects a 5.4x 2011 P/DCFPS multiple consistent with this discount. **Risks** Since there aren't any apparent financial issues, the biggest risks that TLM has always faced relate to development project start-ups and with its newer unconventional strategy, N.A. natural gas pricing, especially with a relatively low hedge position.

# APPENDIX

**COMPANIES MENTIONED**
Anadarko Petroleum (WL) (APC.N, Sell)
Apache Corp (WL) (APA.N, Hold)
Canadian Natural Resources (CNQ.TO, Buy)
Devon Energy (DVN.N, Hold)
Encana Corporation (ECA.TO, Hold)
EOG Resources Inc (WL) (EOG.N, Hold)
Forest Oil (FST.N, Hold)
Murphy Oil (MUR.N, Sell)
Newfield Exploration (WL) (NFX.N, Hold)
Nexen Inc (NXY.TO, Hold)
Noble Energy (NBL.N, Buy)
Occidental Petroleum Corporation (OXY.N, Buy)
Pioneer Natural Resources (PXD.N, Hold)
Talisman Energy (TLM.TO, Hold)

**ANALYST CERTIFICATION**
Each author of this research report hereby certifies that (i) the views expressed in the research report accurately reflect his or her personal views about any and all of the subject securities or issuers and (ii) no part of his or her compensation was, is, or will be related, directly or indirectly, to the specific recommendations or views expressed in this report**: John Herrlin, Bob Parija.**

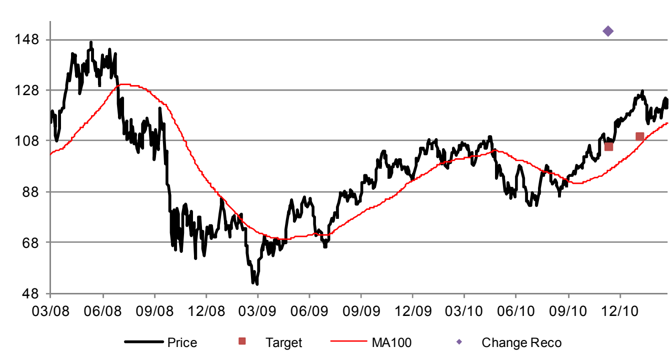
**Historical Price: Anadarko Petroleum (WL) (APC.N)**




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Sell |
| | | 19/11/10 | New Target: 53.5 |
| | | 13/01/11 | New Target: 61.0 |

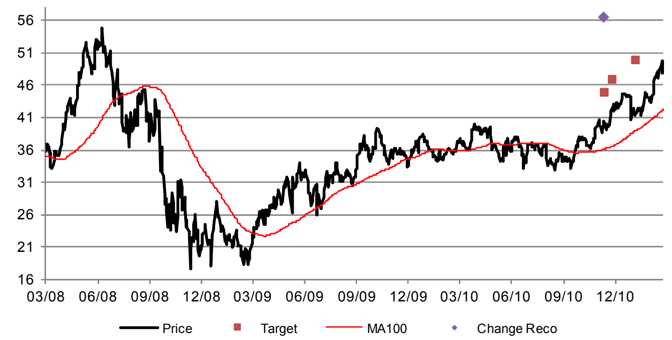
**Historical Price: Apache Corp (WL) (APA.N)**




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 106.0 |
| | | 13/01/11 | New Target: 110.0 |

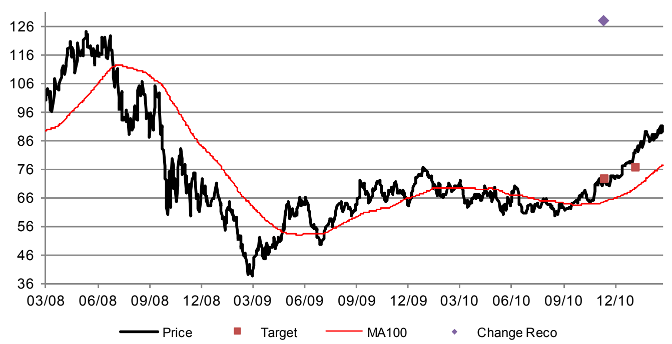
### Historical Price: Canadian Natural Resources (CNQ.TO)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Buy |
| | | 19/11/10 | New Target: 45.0 |
| | | 03/12/10 | New Target: 47.0 |
| | | 13/01/11 | New Target: 50.0 |

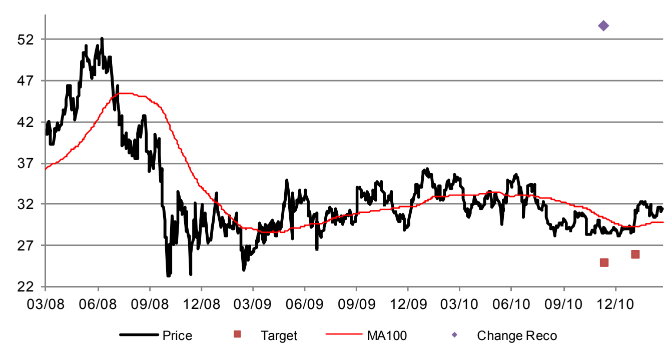
### Historical Price: Devon Energy (DVN.N)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 73.0 |
| | | 13/01/11 | New Target: 77.0 |

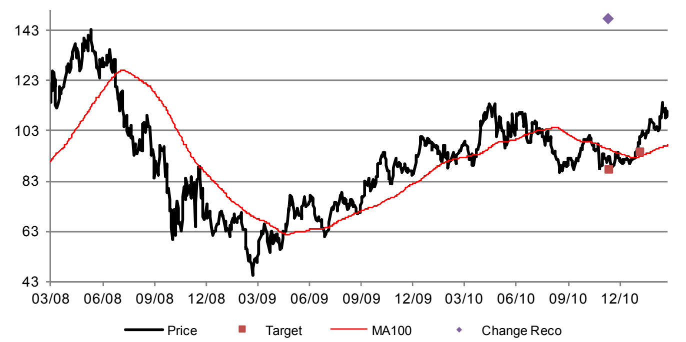
### Historical Price: Encana Corporation (ECA.TO)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 25.0 |
| | | 13/01/11 | New Target: 26.0 |

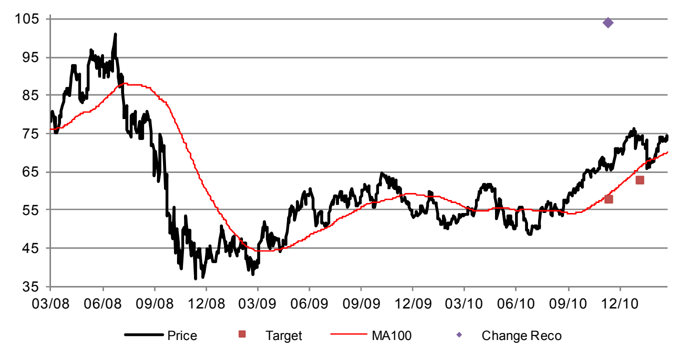
## Historical Price: EOG Resources Inc (WL) (EOG.N)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 88.0 |
| | | 13/01/11 | New Target: 95.0 |

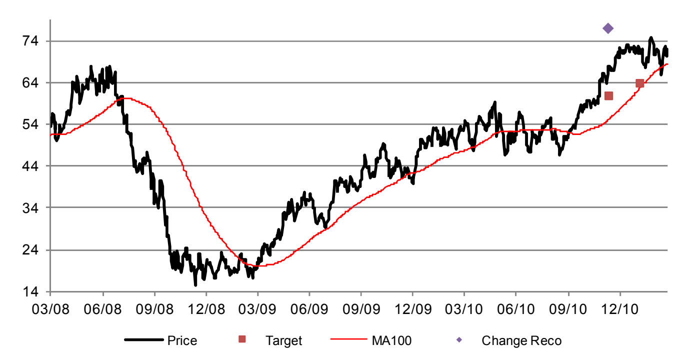
## Historical Price: Murphy Oil (MUR.N)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Sell |
| | | 19/11/10 | New Target: 58.0 |
| | | 13/01/11 | New Target: 63.0 |

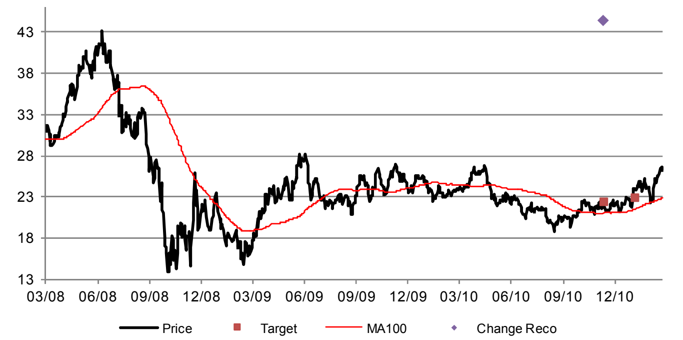
## Historical Price: Newfield Exploration (WL) (NFX.N)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 61.0 |
| | | 13/01/11 | New Target: 64.0 |

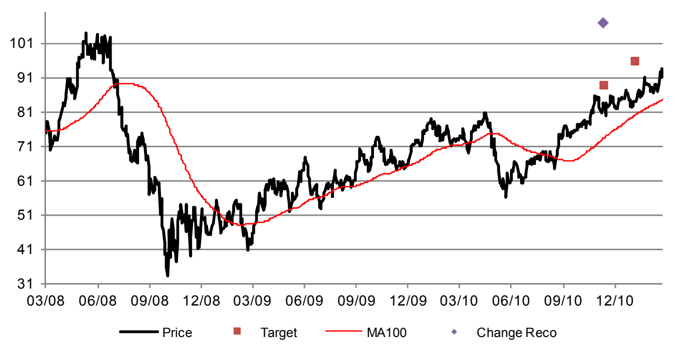
**Historical Price: Nexen Inc (NXY.TO)**




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 22.5 |
| | | 13/01/11 | New Target: 23.0 |

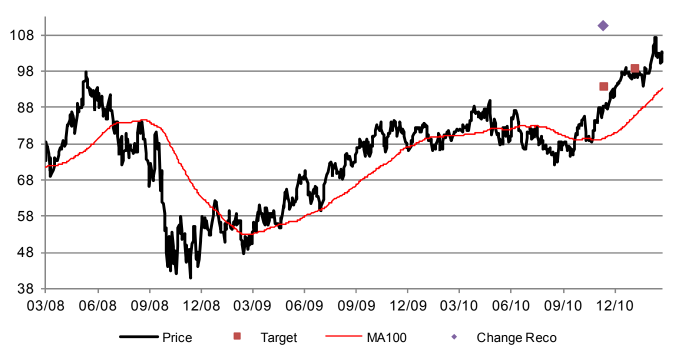
**Historical Price: Noble Energy (NBL.N)**




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Buy |
| | | 19/11/10 | New Target: 89.0 |
| | | 13/01/11 | New Target: 96.0 |

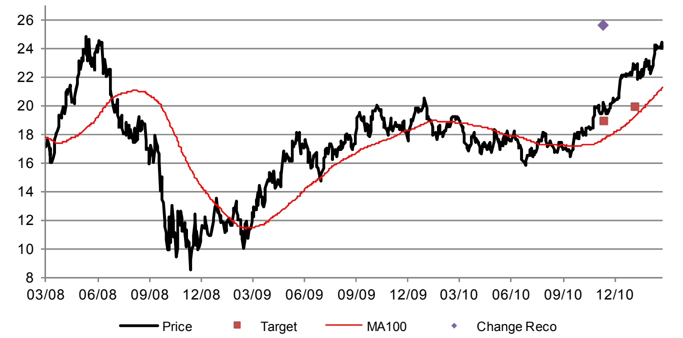
**Historical Price: Occidental Petroleum Corporation (OXY.N)**




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Buy |
| | | 19/11/10 | New Target: 94.0 |
| | | 13/01/11 | New Target: 99.0 |

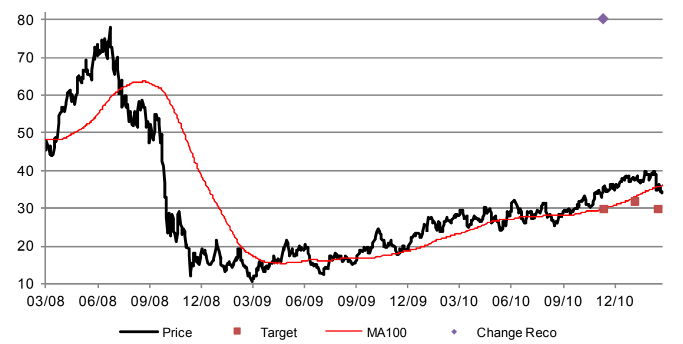
### Historical Price: Talisman Energy (TLM.TO)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 19.0 |
| | | 13/01/11 | New Target: 20.0 |

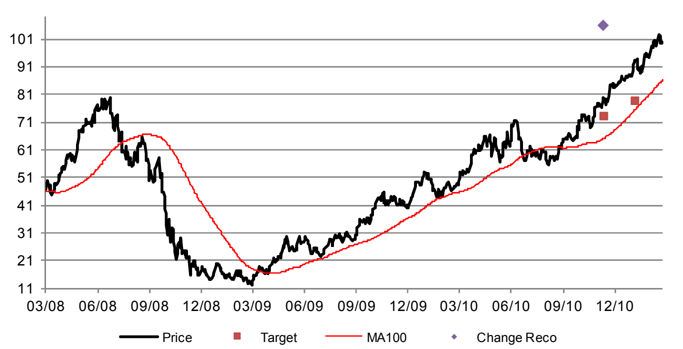
### Historical Price: Forest Oil (FST.N)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 30.0 |
| | | 13/01/11 | New Target: 32.0 |
| | | 23/02/11 | New Target: 30.0 |

### Historical Price: Pioneer Natural Resources (WL) (PXD.N)




Source: SG Cross Asset Research

| 2008/2009 | Change | 2010/2011 | Change |
|---|---|---|---|
| | | 19/11/10 | New Rating: Hold |
| | | 19/11/10 | New Target: 73.5 |
| | | 13/01/11 | New Target: 79.0 |

**SG RATINGS**

**BUY:** expected total return of 10% or more over a 12 month period.

**HOLD:** expected total return between -10% and +10% over a 12 month period.

**SELL:** expected total return of -10% or worse over a 12 month period.

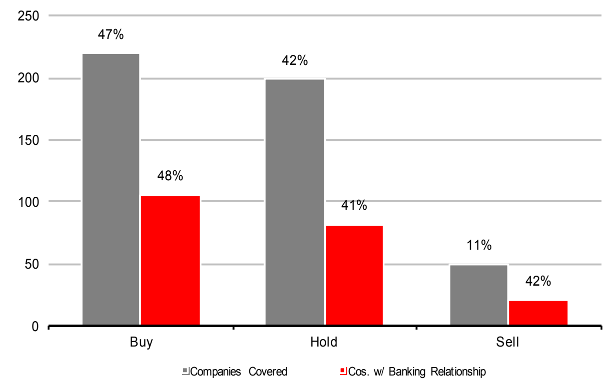
**Sector Weighting Definition:**
The sector weightings are assigned by the SG Equity Research Strategist and are distinct and separate from SG research analyst ratings. They are based on the relevant MSCI.

**OVERWEIGHT:** sector expected to outperform the relevant broad market benchmark over the next 12 months.

**NEUTRAL:** sector expected to perform in-line with the relevant broad market benchmark over the next 12 months.

**UNDERWEIGHT:** sector expected to underperform the relevant broad market benchmark over the next 12 months.

**Equity rating and dispersion relationship**




Source: SG Cross Asset Research

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**IMPORTANT DISCLOSURESIMPORTANT DISCLOSURES**

| | |
|---|---|
| Anadarko Petroleum | SG acted as co-manager in Anadarko Petroleum's senior high grade bond issue. |
| Anadarko Petroleum | SG acted as joint bookrunner in Anadarko Petroleum's senior bond issue. |
| Apache Corp | SG acted as Co-manager in Apache Corp's bond issue. |
| BP | SG is acting as joint bookrunner in BP's senior bond issue (BP 4yr and 7yr Euro). |
| BP | SG is acting as passive bookrunner in BP's USD bond issue. |
| BP | SG is acting as one fo the Mandated Lead Arrangers and Bookrunner for a loan granted to BP. |
| EOG Resources Inc | SG acted as joint lead-manager in EOG Resources' bond issue. |
| EOG Resources Inc | SG acted as co-manager of EOG Resources INC's senior bond issue. |
| Noble Energy | SG acted as co-manager in Noble Energy's bond issue. |
| Occidental Petroleum Corporation | SG acted as co manager in Occidental Petroleum's senior high grade bond issue. |
| Talisman Energy | SG acted as co-manager in Talisman Energy's bond issue. |

SG or its affiliates expect to receive or intend to seek compensation for investment banking services in the next 3 months from BP.
SG or its affiliates have received compensation for investment banking services in the past 12 months from Anadarko Petroleum, Apache Corp, BP, EOG Resources Inc, Noble Energy, Occidental Petroleum Corporation, Talisman Energy.
SG or its affiliates managed or co-managed in the past 12 months a public offering of securities of Anadarko Petroleum, Apache Corp, BP, EOG Resources Inc, Noble Energy, Occidental Petroleum Corporation, Talisman Energy.
SGAS had a non-investment banking non-securities services client relationship during the past 12 months with Anadarko Petroleum, Apache Corp, Canadian Natural Resources, Devon Energy, EOG Resources Inc, Encana Corporation, Murphy Oil, Newfield Exploration, Nexen Inc, Noble Energy, Occidental Petroleum Corporation, Pioneer Natural Resources, Talisman Energy.

SGAS had a non-investment banking securities-related services client relationship during the past 12 months with BP.
SGAS received compensation for products and services other than investment banking services in the past 12 months from Anadarko Petroleum, Apache Corp, BP, Canadian Natural Resources, Devon Energy, EOG Resources Inc, Encana Corporation, Murphy Oil, Newfield Exploration, Nexen Inc, Noble Energy, Occidental Petroleum Corporation, Pioneer Natural Resources, Talisman Energy.
SGCIB received compensation for products and services other than investment banking services in the past 12 months from BP.

from complying with Section 27 of the FAA on recommendations; and (3) the exemption set out in Regulation 35 of the FAR, which exempts SG from complying with Section 36 of the FAA on disclosure of certain interests in securities.

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Steven C. Dixon
*Executive Vice President - Operations*
*Chief Operating Officer*

Securities and Exchange Commission
100 F Street, NE
Washington, DC 20549-1090
Attention: Nancy M. Morris, Secretary

Re: Proposed Rule Changes to Modernize Oil and Gas Reporting Requirements

Ladies and Gentlemen:

Chesapeake Energy Corporation submits this letter in response to the Securities and Exchange Commission's request for comments on proposed rule revisions of the disclosure requirements relating to oil and natural gas reserves. Chesapeake commends the Commission for producing a significantly modernized and principles-based oil and gas reporting regime, one that should be capable of adapting to industry changes and new technologies in the years ahead.

Chesapeake welcomes this opportunity to comment on elements of the proposed rules that we believe should be considered further. As the largest producer of natural gas in the United States and the most active driller of new wells, we have focused these comments on our areas of greatest interest, especially the reporting of natural gas reserves. Our comments are first presented in short form immediately below and then in more detail in the numbered sections following the first portion of this letter.

1. The proposal to use 12-month average prices for calculating oil and natural gas reserves is a decided improvement over the current single-day, fiscal year-end pricing method. However, we propose that the first day, instead of the last day, of each month be used for pricing as a way to provide additional time to filers. Also, we strongly believe the pricing method used for accounting purposes should be changed to conform to the proposed pricing method for reserve estimate disclosures outside the financial statements.

2. We believe that requiring a PUD to be drilled within five years of its initial booking is an unreasonably short timeframe given the goal of presenting more transparent information about the potential size of continuous accumulation reservoirs. Instead, we would recommend that if the Commission believes some time deadline is necessary, then we would suggest a ten year deadline. We would note that this will still lead to the understatement of the size of continuous accumulation reservoirs given that formations such as the Barnett, Fayetteville, Haynesville and Marcellus Shales will take decades to fully develop. In addition, we believe disclosure of historical data regarding the drilling and conversion of PUDs will be useful information for investors, but believe mandating disclosure of forward-looking information regarding PUD

development plans and drilling schedules would lead to unnecessary shareholder litigation and would require disclosure of too much information to a company's competitors.

3. We support the optional reporting of "probable" and "possible" reserves as proposed, but we believe additional guidance as to the level of documentation and support required for such reserve estimates is needed.

4. The proposed definitions of "conventional" and "continuous" accumulations are acceptable, but we believe the disclosure of reserve, well and acreage information, divided between such accumulations, should be optional and not mandatory.

5. The proposed "reliable technology" definition/standard should be reconsidered. Requiring 90% accuracy for any single tool or set of data to be considered reliable technology is in our experience and opinion beyond reasonable certainty, and reliable technology should be defined in terms of the combination of all technology and data available to produce reasonable certainty. We also oppose the proposed requirement that companies disclose the technologies used in making material additions to proved reserves.

6. An oversight board should be established to recommend updated guidance and to propose rule changes to the Commission in response to new technologies.

Each of these points is discussed in more detail below.

## 1. PRICING OF RESERVES

***12-Month Average Prices.*** In our comment letter on the Concept Release, we observed that using a single-day spot price to calculate oil and natural gas reserves does not yield a fair representation of reserve quantities or reserve base value. We support the proposed change to Regulation S-X Rule 4-10 to require the use of an average price over a 12-month period. While not necessarily predictive of future prices, it will alleviate many of the valuation issues created by commodity price volatility.

While we believe that using an average of the price on one day of each of the preceding 12 months is a fair way to determine a one-year average price, we propose that the Commission modify its proposal to use the first day, instead of the last day, of each month in the 12-month pricing period. This would give preparers an additional 30 days to complete reserve estimates. We believe this lag should be sufficient to address the compressed time frame of accelerated filing deadlines and at the same time would provide a reasonable approximation of current pricing.

***Optional Sensitivity Case Analysis.*** Chesapeake supports the option to disclose oil and natural gas reserves using an alternative pricing scenario. We believe information based on such alternative pricing scenarios would provide investors a better view of management's analysis of future prices.

***Prices Used for Accounting Purposes.*** We do not support, and strongly disagree with, the proposal to delink the methods of pricing future reserves for accounting purposes and for other required reserve disclosures. As proposed, a company would disclose proved reserves using a value based on average historical prices over a 12-month period pursuant to Item 102 of Regulation S-K, i.e., in Item 2 of Form 10-K. The unaudited reserve disclosures required by SFAS 69 would use the same pricing methodology and would be consistent with the disclosures required in Item 2. The financial statements, however, would continue to use single-day, period-end pricing to calculate unit-of-production depreciation and depletion rates and, for full-cost companies, to apply the ceiling test to determine the limitation on capitalized costs.

To provide for more clarity and less confusion, we believe companies should be required to use the same prices for accounting purposes as for disclosure outside of the financial statements. Maintaining separate reserve books using different prices would be burdensome for a company's reserve engineering and accounting staff without any counterbalancing benefit to investors. We also believe that any changes to the full-cost accounting rules which would be necessary to accommodate the new pricing methodology can be achieved without significant controversy or delay. We believe the proposal would suffer further if the Commission were to impose different pricing methods on full-cost and successful-efforts companies, a possibility raised in the following request for comment: "Should we require, or allow, a company using the successful efforts accounting method to use an average price but require companies using the full cost accounting method to use a single-day year-end price?" We see no basis for such a difference.

If proved reserves were calculated using average prices for accounting purposes, we would expect to see less volatility in depreciation rates, and, more importantly, full-cost companies such as Chesapeake would be less exposed to ceiling-test write-downs resulting from temporary volatility in commodity prices. Under current rules, an anomalous commodity price decline on a single day can result in the write-down of long-term oil and natural gas assets that have suffered no substantive decline in value. For example, during the recent 12-month period ending June 30, 2008, our depreciation rates and ceiling test calculations were based on end-of-period, single-day prices for natural gas and oil prices that increased more than 90% from June 30, 2007.

| | Natural Gas | Oil |
|---|---|---|
| 6/30/07 | $ 6.80 | $ 70.33 |
| 9/30/07 | $ 6.38 | $ 81.56 |
| 12/31/07 | $ 6.80 | $ 96.01 |
| 3/31/08 | $ 9.37 | $101.60 |
| 6/30/08 | $13.10 | $140.02 |

Subsequent to June 30, 2008, the price of natural gas has now fallen by almost 50% and the price of oil by more than 30%, highlighting the tremendous volatility associated with current oil and natural gas prices. We believe average pricing would help dampen this extreme volatility in commodity prices and its unpredictable results on full-cost companies' financial statements.

If the final rules adopted maintain the proposed dichotomy in pricing methods, we believe companies should be allowed, but not required, to explain the difference and disclose the impact on the calculation of depreciation and any ceiling write-down.

## 2. PROVED UNDEVELOPED RESERVES

Chesapeake strongly supports the effort to bring consistency to proved reserves definitions. In particular, we believe it is appropriate to amend the definition of "proved undeveloped reserves" to replace the requirement that productivity be "certain" for areas beyond the immediate area of known proved reserves with a "reasonably certain" requirement. Elimination of the arbitrary rule that a PUD location can only exist in the immediately adjacent offsetting unit is consistent with advancements in technologies and is especially applicable in continuous accumulations. PUDs should in fact be determined based upon the totality of data available to the evaluator and not governed by narrow rules made obsolete by new technology.

***The Five-Year Rule.*** In a principles-based reporting regime, however, the Commission's proposed "five-year rule" for PUDs is overly restrictive. The proposal would prohibit a company from assigning proved status to undrilled locations if the locations are not scheduled to be drilled within five years, absent unusual circumstances. This arbitrary limitation on PUDs seems to be driven by the suspicion that some companies are booking PUDs they never intend to drill. Without commenting on the existence or extent of this perceived abuse, we know this limitation would penalize our company and other companies similarly situated with large leasehold inventories and expansive drilling programs focused on continuous accumulation reservoirs. We have made substantial investments in leasehold acreage for a number of years, and under the proposed rules we anticipate that we would have more proved locations than we can drill in five years, even though we are the most active driller of new wells in the U.S. To the investment community, our drilling backlog is one of the best indicators of the strength of our company. The five-year rule applied to Chesapeake and our peer group of companies strikes us an unreasonably short given the decades that it will take to develop reservoirs such as the Barnett, Fayetteville, Haynesville and Marcellus Shales. The exception for unusual circumstances that justify a longer time, such as particularly complex projects in remote areas, would not seem to apply to a substantial portion of our PUDs.

All companies with substantial continuous accumulation PUDs will likely be constrained by the five-year rule. Continuous accumulations cover vast areas that can be classified as proved reserves through appropriate data collection. These accumulations typically require intensive drilling with tight spacing due to small drainage areas. Limiting booking of proved undeveloped locations to five years in these accumulations simply has no basis in science and is inappropriate. No such time frame is applied to reserve reporting in the mining industry. When coupled with the limited potential for drainage from offset drilling regardless of producing time and volume, a PUD within these accumulations remains valid over an extremely long time.

Additionally, astute investors do not look at reserve volume alone when evaluating a company. They also look at the discounted value of the future net revenue of those reserves. We believe the requirement to present value PUDs largely eliminates the need for an arbitrary cutoff such as five years. If the Commission must require some time frame to show drilling development intention, then we suggest ten years.

***Expanded Reporting of PUDs.*** The proposal calls for disclosure that would demonstrate clearly a company's record of converting PUDs to proved developed reserves. Proposed Item 1203 requires disclosure of the quantity of such converted reserves and the investment made in PUD conversion for the past five years. We believe this historical information would be useful to the Commission staff and investors in assessing a company's PUD classification. Disclosure should go a long way toward exposing abuse and, unlike the five-year cutoff, would not punish companies whose legitimate development horizons are longer than five years. While we generally support the expanded historical information on PUDs proposed, we are wary of the proposed requirements for forward-looking information, particularly the requirement in Item 1203 to disclose plans to develop PUDs and to further develop proved reserves and in Item 1209 to disclose anticipated capital expenditures directed to specific development purposes (conversion of PUDs to proved developed, probable to proved, and possible to probable or proved) and anticipated exploratory activities, well drilling and production. We believe that mandating such detailed disclosures for all registrants is not practical and may expose companies to the expense of defending lawsuits when future results differ materially from disclosed plans and also provides too much information to a company's competitors. We would propose that the Commission make such disclosures optional, using them as examples of information that may be appropriate in discussing known trends, demands, commitments, etc.

## 3. PROBABLE AND POSSIBLE RESERVES REPORTING

Perhaps never before in our nation's history has it been more important to understand our energy reserves, resources and options for the future. We applaud and support the Commission's proposal to allow companies to disclose reserve volumes beyond proved. More complete and thorough disclosure of the volume and geographic location of natural gas and oil controlled by companies will increase the understanding of the total energy supply. This understanding will lead to better decisions by policy makers and stakeholders in regard to our nation's energy choices in the future.

Chesapeake supports the Commission's proposal not to make the disclosure of probable and possible reserves mandatory for all companies. We would, however, urge the Commission to provide guidance as to the level of documentation and support required for reporting probable and possible reserve estimates. The backup for proved reserves has evolved over many years and is generally well understood in the industry. We expect less is required for documentation of unproved reserves, but companies may be reluctant to disclose unproved reserves, especially in filed reports, without knowing the underlying evidentiary standards that will apply. Further, without this guidance at the outset, it may take a number of years before there is reasonable comparability in the reporting of unproved reserves.

## 4. CONVENTIONAL AND CONTINUOUS ACCUMULATIONS

We question the usefulness to readers of our Commission reports of separately disclosing reserves, wells and acreage by conventional and continuous accumulations. We believe this fragmented manner of reporting should be eliminated or, for companies that want to highlight the split of their properties between conventional and continuous accumulations, be made optional. Since the same proposed rules govern reserve estimations in both types of accumulations, we believe that tracking and disclosing them separately is unnecessarily burdensome to filers and has minimal benefit to readers.

## 5. RELIABLE TECHNOLOGY

***Standards for Single Technology.*** As defined, reliable technology is technology that has been proved empirically to lead to correct conclusions in 90% or more of its applications. We believe this is an unreasonably high bar for a single technology involving interpretation of data in our industry. Further, under the proposed definition, reliable technology must also be widely accepted in the oil and gas industry. This requirement would seem to exclude proprietary techniques that are not generally known or used, even though they have been field tested by a company or contractor and have demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation. If wide industry acceptance is a criterion for reliable technology, companies will need to choose between the competitive advantage an innovative, internally developed technology provides and new reserves that might be booked if the technology were made public.

## 6. FUTURE REVISIONS AND UPDATES

The Concept Release asked for industry input in regard to future oversight and rule-making procedures, yet the proposed rules are silent on this issue. Our industry will continue to evolve. We are producing today from reservoirs not envisioned as productive just a few years ago. Predicting how technology and increased knowledge will alter our industry is difficult if not impossible. The proposed rules would seem to leave ample room for change and growth in our knowledge and still provide complete and accurate disclosures. There is a risk, however, that this flexibility will be eroded over time in the same way existing rules have become inappropriate for technological advances introduced over the past 30 years.

Chesapeake supports and advocates the formation of an oversight board to monitor the appropriateness of oil and natural gas disclosure rules. The board would accept continuous industry feedback and input, filter that input and make recommendations for change, if warranted, to the Commission. We believe a formal oversight board would be an important enhancement to the refinements expected to continue through occasional guidance documents and comment letters issued by the Commission and staff. The mission of the oversight board would be to ensure that the principles-based rules now being proposed are not diluted through narrow and rigid interpretations.

## 7. CONCLUSION

Overall, Chesapeake applauds these long needed and appropriate changes and enhancements proposed by the Commission. The rules proposed are largely principles-based and contain enough flexibility to be responsive to future technological innovation in our industry in the years ahead. We believe the Commission has done well in listening to industry voices and developing several compromises that benefit all stakeholders. Please accept these comments and consider them closely as we sincerely believe they would enhance the proposed rules.

Best regards,

Steven C. Dixon

Chief Operating Officer

**Exxon Mobil Corporation**
5959 Las Colinas Boulevard
Irving, TX 75039-2298
972-444-1202 Telephone
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**Patrick T. Mulva**
Vice President and Controller

ExxonMobil

September 5, 2008

Ms. Florence Harmon
Acting Secretary
Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549-1090

**Re: File Number S7-15-08 – Modernization of the Oil and Gas Reporting Requirements**

Dear Ms. Harmon:

Exxon Mobil Corporation would like to express its support for the Commission's project to re-examine the reporting requirements for oil and gas reserves. The reporting of oil and gas reserves is very important to ExxonMobil, our current and prospective shareholders and other users of our financial statements. The Commission's recent rule proposal addresses many important issues that have been long-time concerns to the oil and gas industry. It is clear to us that the staff has been methodical and comprehensive in developing the rule proposal and we appreciate this effort.

We also note that the proposal positively addresses most of the key recommendations which the American Petroleum Institute (API) and ExxonMobil offered on the earlier Concept Release. We are particularly supportive of the proposals to use 12-month average prices to calculate reserves; to allow the inclusion of tar sands and other non-traditional resources in oil and gas reserves; and to revise the recognition threshold for proved undeveloped reserves. We also believe that most of the proposed technical and definitional changes are consistent with the Society of Petroleum Engineers' (SPE) Petroleum Resources Management System (PRMS) for the reporting of proved reserves. We believe this alignment will assist in the acceptance, understanding and implementation of the new rules. We also believe that many of the proposed changes in the reserves recognition guidelines appear to be principles-based in nature and thus will be robust and flexible in addressing future industry technology changes.

ExxonMobil participated in the development of the API comment letter on the rule proposal, which was filed on August 20, 2008. We fully endorse the positions and recommendations in that letter. To further support the API letter, ExxonMobil provides comments in the attachment that address all of the questions posed in the Commission's rule proposal.

As noted in the API letter, ExxonMobil is very concerned about the extensive new disclosure requirements included in the proposal, most of which were not discussed in the Concept Release. The new disclosures are extensive in scope and will require a significant implementation effort, including costly systems changes and retraining of our personnel. The cost-benefit analysis section of the proposal estimates that the new rules will require an incremental effort of 35 hours per registrant. We believe this is significantly understated and that for ExxonMobil the incremental effort will be in the range of 15,000 to 20,000 hours. More importantly, we believe some of the proposed disclosures are of little value to financial statement users, do not justify the high implementation costs and can cause competitive damage to the disclosing company in some instances. We believe these disclosures are contrary to recent Commission efforts to reduce the complexity of the U.S. reporting system.

In analyzing the rule proposal, we noted several common characteristics of the disclosures that cause us the greatest concern. We would encourage the staff to consider these aspects when deliberating on the final rule proposal. We summarize these below and our detailed responses in the attachment expand on these concepts and provide specific recommendations in each area of the rule proposal.

**Level of Granularity**

Many of the proposed disclosures require a degree of granularity not currently present in our reporting systems and will necessitate costly changes. We believe data disclosures that go beyond what we use to manage the business on a day to day basis are inherently excessive. For example, we believe the proposed segmentation of reserves and drill well data along so many different parameters will significantly increase the length and complexity of the disclosures, while adding little incremental value for investors and financial statement users. We particularly question the value of drill well data to investors and whether it provides any substantial insights to financial statement users in assessing the economic value of a company's operations.

**Anti-abuse Measures**

From the discussion in the rule proposal, it appears that some of the new disclosures were added as anti-abuse measures. For example, there appears to be a concern that some companies may be too aggressive in adding new reserves under the proposed new definition of "reliable technology" and that additional disclosures would help prevent that. Also, the extensive new disclosures around proved undeveloped reserves (PUDs), including the aging and tracking of PUDs by their year of recognition and the tracking of related investment dollars, seem to be driven by this concern. Similarly, the disclosures of the qualifications of company reserves estimators also seems to be an anti-abuse measure and essentially amounts to a duplicative disclosure and certification for the reserves estimation process versus what is already required under the Sarbanes-Oxley

Act. We believe that disclosures are an ineffective and costly approach to addressing internal control considerations and unnecessarily add to the complexity of the U.S. reporting system. We believe that abuse concerns are more than adequately addressed by the Sarbanes-Oxley compliance systems that companies have implemented at great expense over the last few years.

**Bright Line Tests**

We also note that many of the proposed disclosures contain bright line tests or definitions that supplant the exercise of management judgment in tailoring disclosures to address the material aspects of a company's business from a management perspective. We believe this approach is inconsistent with the objective of a principles-based disclosure system. Similar to other judgmental accounting or reporting areas, we believe company personnel and management are in the best position to make reasonable judgments about segmentation and level of detail based on their own company's specific facts and circumstances. We also believe that the use of bright line tests potentially requires companies, in some instances, to disclose information that would cause competitive damage. For example, we believe there is a strong potential for competitive damage to companies from some of the requirements to disclose information at the field or basin level. Such disclosures can undermine the negotiating positions of companies in future property sale transactions, unitization agreements or other asset transfers. Also, information about individual fields or basins is sensitive data that is often subject to restrictions by the national governments that have awarded the concession rights. For the above reasons, we strongly recommend that the staff reconsider the use of bright line tests and requirements throughout the rule proposal as these almost always lead to unnecessary complexity and other unintended consequences.

**Duplication**

In some cases, we believe the proposed disclosures require duplicative work. The key example of this is the proposed requirement for a dual pricing system. As highlighted in the API comment letter, the rule proposal would require reserves to be calculated on two different bases: one using 12-month average prices for reserves disclosure purposes and one using single-day, year-end prices for financial statement accounting purposes. This will effectively double the required amount of record keeping for year-end reporting purposes and is the single costliest feature of the rule proposal. We believe this requirement would break the link between the required reserves disclosures and the underlying financial statement accounting, which we believe is inconsistent with an effective and transparent reporting model. We are not aware of any other area in the accounting literature in which the accounting and the related underlying disclosures are calculated on different bases. We also do not believe that the use of two different pricing bases would add any meaningful value to financial statement users. For these reasons, we strongly recommend that the staff align the accounting and reserves disclosure requirements on the 12-month average price basis in the final rules.

## Alignment with FASB

There are several questions in the rule proposal which indicate that the staff believes that the Financial Accounting Standards Board (FASB) may not amend SFAS 19, SFAS 25 and SFAS 69 to conform to the new SEC disclosure rules. This is a potential outcome that would be extremely costly and disappointing to ExxonMobil and the rest of the oil and gas industry. From the standpoint that the FASB derives their authority to set accounting standards from the Commission, we encourage the staff to exercise leadership to ensure that the final rule proposal and the related financial accounting standards are conformed to establish a single consistent regulatory framework. We believe a dual reporting framework and attendant requirements to reconcile differences would be extremely costly to companies and confusing to financial statement users. We also believe such an outcome would be contrary to the Commission's efforts to reduce the complexity of the U.S. financial reporting system.

ExxonMobil appreciates the Commission's efforts to re-examine the reserves disclosure system and to provide companies with an opportunity to comment. Representatives of ExxonMobil would welcome the opportunity to discuss our response with the Commission's staff, or any other questions that the staff may have, as this project progresses.

Sincerely,

| | | |
|---|---|---|
| cc: | Mr. Glenn Brady | Extractive Activities Research Project, IASB |
| | Mr. Robert Garnett | IASB |
| | Mr. George Batavick | FASB |

**<u>RESPONSES TO QUESTIONS IN SEC RULE PROPOSAL ENTITLED: "MODERNIZATION OF THE OIL AND GAS REPORTING REQUIREMENTS"</u>**

## II. Revisions and Additions to the Definition Section of Rule 4-10 of Regulation S-X

### B. Year-End Pricing

#### 1. 12-month average price

*Should the economic producibility of a company's oil and gas reserves be based on a 12-month historical average price? Should we consider an historical average price over a shorter period of time, such as three, six, or nine months? Should we consider a longer period of time, such as two years? If so, why?*

We strongly recommend that all reserves disclosures and related accounting be based on the same 12-month average pricing methodology. This approach significantly reduces the impact of short-term price volatility that can arise from the use of single day prices and maintains comparability of disclosures among companies. We believe an average price based on a 12-month period is an appropriate time period to determine the pricing and provides a basis more consistent with the long-term nature of the oil and gas business.

*Should we require a different pricing method? Should we require the use of futures prices instead of historical prices? Is there enough information on futures prices and appropriate differentials for all products in all geographic areas to provide sufficient reporting consistency and comparability?*

No, we do not recommend the use of a different pricing method. As for the use of futures prices, we believe that the futures markets in many geographic areas lack the breadth and depth of activity that will be required to support such an approach. If futures were the reporting basis, we anticipate that company estimates will be required to address the lack of futures market prices or futures market prices in thinly traded markets that were believed to be non-representative. We believe that the resulting reserves reporting will have an unacceptable degree of inconsistency and lack of comparability between companies.

*Should the average price be calculated based on the prices on the last day of each month during the 12-month period, as proposed? Is there another method to calculate the price that would be more representative of the 12-month average, such as prices on the first day of each month? Why would such a method be preferable?*

Consistent with the earlier API recommendations on the Concept Release, we continue to believe that the 12-month period should run from October 1 of the previous year to September 30 of the reporting year for companies with a fiscal year ending on December 31. We would alternatively recommend that the staff consider changing the 12-month average price to an average of first-of-the-month prices, ending with December 1 for a calendar year company. This will achieve the desired averaging effect and will align with the fiscal year for accounting purposes. It will also help preparers in managing their heavy year-end workloads by providing an additional 30 days to calculate reserves versus the current disclosure requirements. As noted in the API comment letter, many industry companies have indicated that they believe first-of-the-month pricing is preferable for use in the 12-month average price calculation as month-end market prices are more subject to unusual daily price volatility from the close-out of trading positions and other month-end trading activities.

*Should we require, rather than merely permit, disclosure based on several different pricing methods? If so, which different methods should we require?*

We strongly recommend the use of one consistent pricing basis for all companies. As indicated above, we believe the single price basis should be a 12-month historical average price. Requiring disclosures on several different pricing bases will necessitate costly system and business process changes by preparers without achieving added benefits for users of financial statements. To the contrary, we believe the use of multiple pricing bases will confuse financial statement users and will likely require additional disclosures to explain the differences.

*Should we require a different price, or supplemental disclosure, if circumstances indicate a consistent trend in prices, such as if prices at year-end are materially above or below the average price for that year? If so, should we specify the particular circumstances that would trigger such disclosure, such as a 10%, 20%, or 30% differential between the average price and the year-end price? If so, what circumstances should we specify?*

We do not believe that the use of different prices or the use of supplemental disclosures should be required if year-end prices are different than the average price for that year. The rationale for utilizing average prices is to reduce price volatility associated with prices at a single point in time and to provide a price which is more reflective of the long-term nature of the upstream business. We believe that requiring the use of different prices or the use of supplemental disclosures will undermine the benefits gained from using average prices and re-introduce unnecessary price volatility. If a consistent and significantly different price trend emerges which could materially change the determination of a preparer's proved reserves in future periods, the preparer could disclose the situation and its potential impact.

## 2. Trailing year-end

*Should the price used to determine the economic producibility of oil and gas reserves be based on a time period other than the fiscal year, as some commenters have suggested? If so, how would such pricing be useful? Would the use of a pricing period other than the fiscal year be misleading to investors? Is a lag time between the close of the pricing period and the end of the company's fiscal year necessary? If so, should the pricing period close one month, two months, three months, or more before the end of the fiscal year? Explain why a particular lag time is preferable or necessary. Do accelerated filing deadlines for the periodic reports of larger companies justify using a pricing period ending before the fiscal year end?*

Although we strongly support the use of a 12-month average price, requiring the calculation to be based on month-end prices over the reporting year will make it difficult for companies to calculate their reserves in time to meet the 60-day filing deadline for the Annual Report on Form 10-K. For a calendar year company, the requirement to use month-end prices means that reserves estimating work can not effectively commence until the December 31st price is finalized. Consistent with the earlier API recommendations on the Concept Release, we continue to believe that the 12-month period should run from October 1 of the previous year to September 30 of the reporting year for companies with a fiscal year ending on December 31. We would alternatively suggest that the staff consider changing the 12-month average price to an average of first-of-the-month prices, ending with December 1 for a calendar year company. We believe the use of first-of-the-month prices as an alternative will achieve the desired averaging effect and will align with each registrant's fiscal year for accounting purposes, while also allowing preparers 30 additional days of time to complete reserves estimates. We do not see any significant disadvantages with utilizing first-of-the-month prices versus month-end prices.

## 3. Prices used for accounting purposes

*Should we require companies to use the same prices for accounting purposes as for disclosure outside of the financial statements?*

We strongly recommend that companies be required to use the same pricing basis for the disclosure of reserves quantities and for the related financial accounting under SFAS 19 (primarily the calculation of unit-of-production depreciation and depletion rates). The use of two pricing bases will sever the link between the required disclosures and the related financial accounting which is not consistent with an effective and transparent reporting model.

As noted in our subsequent responses, we do not believe that the use of average prices for accounting purposes will create material differences in unit-of-production depreciation expense from period to period versus the use of year-end prices. To the contrary, the use of average prices will reduce the magnitude of changes that may otherwise be caused by large fluctuations in year-end prices. In any event, we do not think that depreciation expense based on single-day, year-end prices yields a conceptually better accounting result than one based on average prices. Therefore, we believe that the use of two different pricing bases will not add any meaningful value to financial statement users but would certainly place a significant new burden on registrants. For these reasons, we strongly recommend that the accounting and disclosure requirements be aligned on the 12-month average price basis.

*Is there a basis to continue to treat companies using the full cost accounting method differently from companies using the successful efforts accounting method? For example, should we require, or allow, a company using the successful efforts accounting method to use an average price but require companies using the full cost accounting method to use a single-day, year-end price?*

*Should we require companies using the full cost accounting method to use a single-day, year-end price to calculate the limitation on capitalized costs under that accounting method, as proposed? If such a company were to use an average price and prices are higher than the average at year end or at the time the company issues its financial statements, should that company be required to record an impairment charge?*

We believe that all companies subject to Regulation S-X and SFAS 19 and SFAS 69 should use the same price basis for calculating proved reserves. We believe the comparability of reported reserves between all companies is improved, and hence the overall financial reporting system is improved, if all reserves calculations are based on the same consistent price basis.

As to the specific issue of accounting by full cost companies, we believe the Commission should consider modifying Regulation S-X, Rule 4-10 to require full cost companies to calculate impairment charges using the same 12-month average price that will be used for reserves estimates. The arguments for this approach are essentially the same as the ones made for basing proved reserves on 12-month average prices versus single-day, year-end prices. This approach significantly reduces the impact of short-term price volatility that can arise from the use of single day prices, is more consistent with the long-term nature of the oil and gas business and aligns the accounting with the related disclosures. If the prices in effect at year-end are significantly different than the 12-month average prices, a full cost company could disclose this fact as well as the estimated impact of any potential impairment charges should the price trend persist during the ensuing accounting period.

*Should the disclosures required by SFAS 69 be prepared based on different prices than the disclosures required by proposed Section 1200?*

We strongly recommend that all proved reserves disclosures be based on the same 12-month average pricing methodology, including all SFAS 69 disclosures and calculations.

*If proved reserves, for purposes of disclosure outside of the financial statements, other than supplemental information provided pursuant to SFAS 69, are defined differently from reserves for purposes of determining depreciation, should we require disclosure of that fact, including quantification of the difference, if the effect on depreciation is material?*

*What concerns would be raised by rules that require the use of different prices for accounting and disclosure purposes? For example, is it consistent to use an average price to estimate the amount of reserves, but then apply a single-day price to calculate the ceiling test under the full cost accounting method? Would companies have sufficient time to prepare separate reserves estimates for purposes of reserves disclosure on one hand, and calculation of depreciation on the other? Would such a requirement impose an unnecessary burden on companies?*

We recommend the implementation of the same 12-month average pricing methodology for both reserves disclosures and for accounting purposes. We believe the use of a different methodology (such as year-end prices) for determining SFAS 19 depreciation amounts will be unduly costly and burdensome to registrants, confusing to financial statement users, and inconsistent with an effective and transparent reporting model for oil and gas companies. At the same time, however, if a different basis was used for determining proved reserve quantities for SFAS 19 depreciation calculations, we believe it is unlikely that the resultant impact on depreciation provisions will be significant enough to require disclosure. The fact that full cost companies might be in a situation where their disclosed reserves are based on year-average prices but their ceiling test calculations (and possible impairment charges) are based on a single year-end price is inherently inconsistent. In our opinion, this is another good reason to establish a 12-month average pricing methodology for all accounting purposes.

*Will our proposed change to the definitions of proved reserves and proved developed reserves for accounting purposes have an impact on current depreciation amounts or net income and to what degree?*

In view of the typical relationship between the amount of proved reserves and the attendant volume of production during any one accounting period, and our view of the potential changes to proved reserves and proved developed reserves, we believe it is very unlikely that the proposed changes to the reserves definitions will have a material impact on unit-of-production depreciation expense or net income at the time of transition or in subsequent accounting periods.

*If we change the definitions of proved reserves and proved developed reserves to use average pricing for accounting purposes, what would be the impact of that change on current depreciation amounts and on the ceiling test? Would the differences be significant?*

Similar to our response above, we do not believe that a change to average pricing for accounting purposes will create material changes in unit-of-production depreciation expenses or net income at the time of transition or in subsequent accounting periods. We also do not think it will have a material impact on the application of the ceiling test by full cost companies. To the contrary, the use of average prices will reduce the magnitude of changes that may otherwise be caused by large fluctuations in year-end prices.

In any event, we do not think that depreciation expense based on single-day, year-end prices yields a conceptually better accounting result than one based on average prices. Therefore, we believe that the use of two different pricing bases will not add any meaningful value to financial statement users while placing a significant new burden on registrants. For these reasons, we strongly recommend that the accounting and disclosure requirements be aligned on the 12-month average price basis.

### C. Extraction of Bitumen and Other Non-Traditional Resources

*Should we consider the extraction of bitumen from oil sands, extraction of synthetic oil from oil shales, and production of natural gas and synthetic oil and gas from coalbeds to be considered oil and gas producing activities, as proposed? Are there other non-traditional resources whose extraction should be considered oil and gas producing activities? If so, why?*

Yes, we strongly support recognizing the listed activities as oil and gas producing activities. We also strongly support the proposed rule changes which will shift the focus of the definition of oil and gas producing activities to the final product of such activities, regardless of the extraction technology used. If the final product of the activity results in oil or gas similar to that from a "traditional" producing well, then it should be considered an oil and gas activity. We believe this same principle should apply to any future non-traditional resources not specifically enumerated in the rule proposal. This approach will make the rules flexible and robust in addressing future unconventional resources, consistent with a principles-based system.

*The extraction of coal raises issues because it is most often used directly as mined fuel, although hydrocarbons can be extracted from it. As noted above, we propose to include the extraction of coalbed methane as an oil and gas producing activity. However, the actual mining of coal has traditionally been viewed as a mining activity. In most cases, extracted coal is used as feedstock for energy production rather than refined further to extract hydrocarbons.*

*However, as technologies progress, certain processes to extract hydrocarbons from extracted coal, such as coal gasification, may become more prevalent. Applying rules to coal based on the ultimate use of the resource could lead to different disclosure and accounting implications for similar coal mining companies based solely on the coal's end use. How should we address these concerns? Should all coal extraction be considered an oil and gas producing activity? Should it all be considered mining activity? Should the treatment be based on the end use of the coal? Please provide a detailed explanation for your comments.*

The same principle stated in the previous response should apply to coal extraction, i.e. the treatment should be based on the final product produced. If the coal is gasified, then the gas produced will be included with other natural gas reserves. Consistent with this approach, it is possible that a company could have different disclosure requirements depending on the end use of the coal. We believe this approach is sensible as the investment decisions made by the company for each mode of operation will be based on the value and disposition of the end products produced and will be evaluated against alternative investments for producing the same products from traditional mining or oil and gas producing activities.

*Similar issues could arise regarding oil shales, although to a significantly less extent, because those resources currently are used as direct fuel only in limited applications. How should we treat the extraction of oil shales?*

Consistent with a principles-based disclosure system, we believe the same logic from our previous response should apply to the extraction of oil shales.

*If adopted, how would the proposed changes affect the financial statements of producers of non-traditional resources and mining producers?*

These changes will not have a significant impact on ExxonMobil's financial statements and we believe the impact will be similar for other oil and gas companies. For example, the operating results for the extraction of bitumen from oil sands is already reported in the "Upstream" financial segment, so there will be no change in financial statement segmentation. For SFAS 69 Supplemental Oil and Gas reporting, the oil sands data currently shown as mining will be added to the traditional oil and gas data. We believe this will greatly improve the quality and completeness of industry financial reporting practices as it will present upstream operations to investors and other financial statement users on the same basis that company management views such operations. The investment community also views hydrocarbons produced from such resources as an integral part of the upstream oil and gas production business.

### D. Reasonable Certainty and Proved Oil and Gas Reserves

*Is the proposed definition of "reasonable certainty" as "much more likely to be achieved than not" a clear standard? Is the standard in the proposed definition appropriate? Would a different standard be more appropriate?*

*Is the proposed 90% threshold appropriate for defining reasonable certainty when probabilistic methods are used? Should we use another percentage value? If so, what value?*

We believe that most constituents in the reserves reporting process, including companies, investors, financial statement users and regulators, have a good understanding of the concept of reasonable certainty. While we believe the proposed definitional change clarifies the meaning of "reasonable certainty" in a manner that is consistent with the common industry understanding of the term, we suggest that the staff consider using the SPE PRMS definition instead. The PRMS definition of "reasonable certainty" is a "high degree of confidence that quantities would be produced." We believe the two definitions are essentially equivalent and neither change the level of certainty required to recognize proved reserves. However, we believe that alignment of the definitions with the PRMS wherever possible will assist in the acceptance, understanding and implementation of the new rules as the PRMS is the most widely accepted benchmark for classifying reserves in the global energy industry.

Likewise, we support the proposed 90% probability threshold for proved reserves when probabilistic methods are used. This has been a common convention used in other reporting systems and is aligned with the SPE PRMS.

#### 1. New technology

*Is our proposed definition of "reliable technology" appropriate? Should we change any of its proposed criteria, such as widespread acceptance, consistency, or 90% reliability?*

We believe that the proposed addition of the "reliable technology" definition to Rule 4-10 is consistent with a principles-based approach and will enhance and increase the consistency of reserves reporting in accordance with the "reasonable certainty" criteria. We believe the proposed criteria are all appropriate.

We support the proposed criteria for establishing "reliable technology." However, there may be cases where proprietary technology or technology using proprietary data has been demonstrated to be highly reliable, but is not widely available for general use by industry and therefore does not have "widespread acceptance." We recommend that the proposed definition of "reliable technology" be broadened to include these cases.

*Is the open-ended type of definition of "reliable technology" that we propose appropriate? Would permitting the company to determine which technologies to use to determine their reserves estimates be subject to abuse? Do investors have the capacity to distinguish whether a particular technology is reasonable for use in a particular situation? What are the risks associated with adoption of such a definition?*

We believe that the proposed definition is appropriate since it provides the flexibility and scope to include new technologies as they are developed and demonstrated to be reliable. Similar to other judgmental accounting or reporting areas, we believe that company personnel and management are in the best position to make reasonable judgments based on their own company's specific facts, technologies and circumstances. Abuse prevention should be adequately handled by the existing requirements for companies to have in place effective systems of internal controls. We do not believe that investors are generally in the best position to determine whether the use of a specific technology was appropriate for a particular situation. Such determination requires specialized knowledge and technical expertise that investors typically would not have.

*Is the proposed disclosure of the technology used to establish the appropriate level of certainty for material properties in a company's first filing with the Commission and for material additions to reserves estimates in subsequent filings appropriate? Should we require disclosure of the technology used for all properties? Should we require companies currently filing reports with the Commission to disclose the technology used to establish appropriate levels of certainty regarding their currently disclosed reserves estimates?*

We believe the proposed disclosures are not appropriate. It is very difficult to assess the specific contribution that a particular technology may make to a reserves estimate. Multiple technologies are typically used together and the strengths of each are used to yield the most accurate result. Our perspective is that experience, sound professional judgment and process consistency are the key factors in determining reasonable certainty and may be more significant in the determination of the relative certainty of reserve estimates rather than specific technologies. Since experience and professional judgment are very difficult to quantify, we believe that this should not be a disclosure requirement. Moreover, implementing additional processes and controls in order to disclose the "technical methods" will be time-consuming and costly. It is unlikely that this information will provide any benefit to the typical investor or other financial statement user, since its use requires specialized knowledge and technical expertise. The requirement for disclosure of the technologies used could also cause competitive harm given their proprietary nature.

### 2. Probabilistic methods

*Are the proposed definitions of "deterministic estimate" and "probabilistic estimate" appropriate? Should we revise either of these definitions in any way? If so, how?*

*Are the statements regarding the use of deterministic and probabilistic estimates in the proposed definition of "reasonable certainty" appropriate? Should we change them in any way? If so, how?*

We believe the proposed definitions of "deterministic estimate" and "probabilistic estimate" are clear and appropriate. The statements added to the definitions will improve their clarity and acceptance as these are concepts with which the industry is very familiar.

*Should an oil and gas company have the choice of using deterministic or probabilistic methods for reserves estimation, or should we require one method? If we were to require a single method, which one should it be? Why? Would there be greater comparability between companies if only one method was used?*

The selection of assessment methodology for reserves estimation should be at the discretion of companies as both are technically acceptable methods. However, if only a single methodology is to be allowed, the deterministic approach should be selected as it has been the long held industry standard and will be the method most understood by company reserves estimators, financial statement users and regulators. Given the importance of technical and professional judgment in the estimation of reserves, we do not believe the selection of a single method will necessarily improve the comparability of reserves estimation practices between companies.

*Should we require companies to disclose whether they use deterministic or probabilistic methods for their reserves estimates?*

No, we believe such disclosures should be at the option of each company. Regardless of the methodology selected, companies will still be required to achieve the appropriate level of reasonable certainty to justify the recognition of reserves.

### 3. Other revisions related to proved oil and gas reserves

*Should we permit the use of technologies that do not provide direct information on fluid contacts to establish reservoir fluid contacts, provided that they meet the definition of "reliable technology," as proposed?*

Yes, we believe such technologies should be allowed, provided that they meet the definition of "reliable technology." We believe this approach is consistent with a principles-based disclosure system. As we have indicated in other responses, we believe that the reserves estimation process is highly dependent on the application of good management and technical judgment to ensure that the standard of reasonable certainty is obtained for the recognition of proved reserves. We believe a given technology may be "reliable" and appropriate to use in one case, but may not be appropriate for all cases. Use of a particular technology, whether it is to determine reservoir fluid contacts, reservoir continuity, or other reserves parameters, needs to be evaluated and utilized as appropriate on a case by case basis.

*Should there be other requirements to establish that reserves are proved? For example, for a project to be reasonably certain of implementation, is it necessary for the issuer to demonstrate either that it will be able to finance the project from internal cash flow or that it has secured external financing?*

Consistent with our prior response, we believe the principle of "reasonable certainty" should be applicable to all aspects of the reserves recovery process, including financial, commercial and project execution aspects, in addition to the geoscience considerations. Thus, instead of incorporating lists of specific requirements or other bright line tests into the rules, we believe that the evaluation of each aspect should depend on the application of good management and technical judgment, supported by each company's internal control and management certification processes.

### E. Unproved Reserves – "Probable Reserves" and "Possible Reserves"

*Should we permit a company to disclose its probable or possible reserves, as proposed? If so, why?*

We strongly prefer that reserves reporting be limited to proved reserves only as prescribed by the current disclosure requirements. However, we view the proposed optional reporting of probable and possible reserves as an acceptable alternative to mandatory reporting of such reserves in documents filed with the SEC. Any company who chooses to disclose such reserves in their 10-K will need to ensure that they comply with the SEC definitions and methodologies (which are consistent with the SPE PRMS) and be willing to accept a higher risk of additional, unwarranted litigation due to the inherent uncertainty associated with these reserves.

*Should we require, rather than permit, disclosure of probable or possible reserves? If so, why?*

We believe it is critical that the Commission not require the disclosure of probable or possible reserves in filed documents. Financial statement users will not be well served by the mandated inclusion of such resources due to their increased uncertainty and the breadth of methodologies and evaluation techniques that may be employed in their calculation. We also believe that such reporting could expose companies to additional, unwarranted litigation due to their increased uncertainty.

*Should we adopt the proposed definitions of probable reserves and possible reserves?*

*Should we make any revisions to those proposed definitions? If so, how should we revise them?*

The proposed definitions of probable and possible reserves, which broadly conform to PRMS guidelines, are acceptable for companies which elect to report such reserves in their filed documents. However, the SEC should not mandate the use of PRMS methodology if companies choose to disclose probable and possible quantities in public forums other than documents filed with the SEC.

*Are the proposed 50% and 10% probability thresholds appropriate for estimating probable and possible reserves quantities when a company uses probabilistic methods? Should probable reserves have a 60% or 70% probability threshold? Should possible reserves have a 15% or 20% probability threshold? If not, how should we modify them?*

The proposed 50% and 10% probability thresholds are consistent with the PRMS methodology and are acceptable provided they are limited to the optional reporting of probable or possible reserves in documents filed with the Commission.

### F. Definition of "Proved Developed Oil and Gas Reserves"

*Should we revise the definition of proved developed oil and gas reserves, as proposed? Should we make any other revisions to that definition? If so, how should we revise it?*

The proposed definition of proved developed oil and gas reserves is acceptable, since it now covers extraction of resources using technologies other than production through wells. We do not recommend any changes to the rule proposal in this area.

### G. Definition of "Proved Undeveloped Reserves"

#### 1. Proposed replacement of certainty threshold

*Are the proposed revisions appropriate? Would the proposed expansion of the PUDs definition create potential for abuses?*

*Should we replace the current “certainty” threshold for reserves in drilling units beyond immediately adjacent drilling units with a “reasonable certainty” threshold as proposed?*

*Is it appropriate to prohibit a company from assigning proved status to undrilled locations if the locations are not scheduled to be drilled more than five years, absent unusual circumstances, as proposed? Should the proposed time period be shorter or longer than five years? Should it be three years? Should it be longer, such as seven or ten years?*

We believe changing the recognition threshold for PUDs to “reasonable certainty” and allowing the use of “reliable technology” to support their recognition are appropriate changes that will modernize the disclosure system. The changes will improve the internal consistency of the guidelines by establishing one recognition threshold (i.e., reasonable certainty, reliable technology) for all categories of proved reserves. These changes will also make the rules more consistent with a principles-based system by facilitating the application of professional judgment and the application of new technologies as they evolve.

However, we believe the introduction of a “bright line” test for recognizing PUDs that will not be drilled within five years is unduly restrictive and should be deleted. We believe that the recognition of PUDs should continue to be based on management’s comprehensive assessment of the geoscience, financial, commercial and operational aspects of each development project utilizing the standard of reasonable certainty. In the case of PUDs, recognition will be particularly dependent on management’s firm commitment to develop the reserves over the project’s anticipated time horizon. Given the increasing scale and life of industry development projects, we believe the proposed five-year test (or any other “bright line” test) will apply to an increasingly significant percentage of projects and related reserves and, therefore, will not be “unusual” in occurrence as the rule proposal seems to anticipate. Consequently, this additional test will significantly add to the new disclosure burden created by the overall rule proposal.

We strongly recommend that the staff avoid the use of arbitrary time deadlines or other bright line tests throughout the final rule proposal as these will be inconsistent with a principles-based regime. We do not believe that the proposed changes to the PUDs definition, or for that matter any of the other proposed rule changes, increase the risk of abuse. We believe that abuse prevention is adequately addressed by the extensive Sarbanes-Oxley rules that require companies to have in place an effective system of internal controls over their financial reporting and disclosure systems, which includes the reserves reporting process.

*Should the proposed definition specify the types of unusual circumstances that would justify a development schedule longer than five years for reserves that are classified as proved undeveloped reserves?*

Consistent with our previous response, we discourage the creation of detailed check lists or other bright line tests. In this case, we believe it will be difficult to create a comprehensive list of "unusual circumstances" that could occur now or that may occur in the future as the industry continues to evolve. Each case would need to be considered on its own merits.

### 2. Proposed definitions for continuous and conventional accumulations

*Should we provide separate definitions of conventional and continuous accumulations, as proposed? Would separate disclosure of these accumulations be helpful to investors?*

No, we do not believe that separate definitions or disclosures of conventional and continuous accumulations are needed. We believe the disclosures should continue to be differentiated by end-product (i.e. oil and gas) rather than the type of accumulation. We recommend that proposed segmentation by conventional and continuous accumulations be eliminated as we believe this split will be of limited value to financial statement users.

*Should we revise our proposed definition of "continuous accumulations" in any way? For example, should the proposed definition provide examples of such accumulations? If so, how should we revise it?*

As stated in the previous response, we do not believe this definition is needed and should be eliminated in its entirety.

*Should we revise our proposed definition of "conventional accumulations" in any way? If so, how should we revise it?*

As stated in the previous response, we do not believe this definition is needed and should be eliminated in its entirety.

### 3. Proposed treatment of improved recovery projects

*Should we expand the definition of proved undeveloped reserves to permit the use of techniques that have been proven effective by actual production from projects in an analogous reservoir in the same geologic formation in the immediate area or by other evidence using reliable technology that establishes reasonable certainty?*

We strongly support the expansion of the definition of proved undeveloped reserves to allow the use of "reliable technology" to establish reasonable certainty of improved recovery. Consistent with the SPE PRMS (2.3.4 Improved Recovery), we recommend the proposed analog description be changed to "a reservoir with analogous rock and fluid properties where a similar established improved recovery project has been successfully applied." This change will make the rules more consistent with a principles-based approach and better allow the application of professional judgment and the use of new technologies as they evolve.

### H. Proposed Definition of Reserves

*Is the proposed definition of "reserves" appropriate? Should we change it in any way? If so, how?*

We generally agree with the proposed definition as it is broadly consistent with the SPE PRMS and current industry application. However there are several aspects which we recommend be clarified in the final rule proposal to avoid confusion and/or potential conflicts with other rules and standards.

The term "legal right to produce" has the potential to exclude many economic interests allowed under existing regulations such as royalty interests. We recommend this requirement be changed to "the legal right to produce, a revenue interest in the production, or other non-operating interest."

The term *"current prices and costs"* should be further described to be consistent with the 12-month average pricing proposed elsewhere in the rule proposal.

The determination of the boundary lines around oil and gas production operations is an important feature of the disclosure rules. We believe the proposed definition in the rule proposal omits some well-established guidance found in the existing rules. Accordingly, we recommend that the definition of the oil and gas production function shown in Instruction 1 to paragraph (a)(16)(i)(a) be replaced with the current definition in Regulation SX 4-10 (1)(c) and FASB 19:

> "For purposes of this section, the oil and gas production function shall normally be regarded as terminating at the outlet valve on the lease or field storage tank; if unusual physical or operational circumstances exist, it may be appropriate to regard the production functions as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal."

We also believe that the definition would be improved if it recognized that oil and gas are fungible commodities and that all in-place hydrocarbons ultimately sold or consumed for beneficial use (e.g. fuel gas) should be included in reported reserves.

### I. Other Proposed Definitions and Reorganization of Definitions

*Are these additional proposed definitions appropriate? Should we revise them in any way?*

*Are there other terms that we have used in the proposal that need to be defined? If so, which terms and how should we define them?*

The additional definitions are appropriate, appear to be comprehensive and will provide helpful guidance. We suggest that the staff also consider the inclusion of the PRMS Glossary (Appendix A) "Glossary of Terms Used in Resources Evaluations."

*Should we alphabetize the definitions, as proposed? Would any undue confusion result from the re-ordering of existing definitions*?

ExxonMobil supports the proposal to alphabetize the definitions and does not believe that it will result in any confusion.

## III. Proposed Amendments to Codify the Oil and Gas Disclosure Requirements in Regulation S-K

### A. Proposed Revisions to Item 102, 801, and 802 of Regulation S-K

*Is the proposed amendment to Instruction 3, limiting it to extractive activities other than oil and gas activities, appropriate? Should we simply call them mining activities?*

Yes, we believe limiting Instruction 3 to extractive activities other than oil and gas activities is appropriate. Since the oil and gas activities will no longer be included, we believe calling them mining activities will be more descriptive and will simplify the guidelines.

*Are there any other aspects of Item 102 that we should revise? If so, what are they and how should they be revised?*

No, we do not believe any other aspects of Item 102 need to be revised.

B. **Proposed New Subpart 1200 of Regulation S-K Codifying Industry Guide 2 Regarding Disclosures by Companies Engaged in Oil and Gas Producing Activities**

1. **Overview**
2. **Proposed Item 1201 (General instructions to oil and gas industry-specific disclosures)**

*Are the proposed general instructions to Subpart 1200 clear and appropriate? Are there any other general instructions that we should include in this proposed Item?*

Yes, we believe the proposed instructions to subpart 1200 are clear and that no other general instructions need to be added.

*For disclosure items requiring tabulated information, should we require companies to adhere to a specified tabular format, instead of permitting companies to reorganize, supplement, or combine the tables?*

No, we do not believe companies should be required to adhere to a specified tabular format. We believe that companies should be permitted the flexibility to present the required data and any supplemental data in a format that is most relevant and meaningful to its operations. This approach is consistent with a principles-based disclosure system.

*In particular, should we permit a company to disclose reserves estimates from conventional accumulations in the same table as it discloses its reserves estimates from continuous accumulations?*

As discussed in previous responses, we do not believe that separate definitions of conventional and continuous accumulations are needed. We believe the disclosures should continue to be differentiated by end-product (i.e. oil and gas) rather than the type of accumulation. We recommend that the staff eliminate the proposed segmentation by conventional and continuous accumulations as we believe this split will be of limited value to financial statement users and greatly increases the complexity of the required disclosures. If the staff continues to believe that such segmentation is warranted, we believe companies should be permitted to disclose reserves estimates from both conventional and continuous accumulations in the same table.

3. **Proposed Item 1202 (Disclosure of reserves)**

   i. **Oil and gas reserves tables**

*Should we permit companies to disclose their probable reserves or possible reserves? Is the probable reserves category, the possible reserves category (or* *both categories) too uncertain to be included as disclosure in a company's public filings? Should we only permit disclosure of probable reserves? What are the advantages and disadvantages of permitting disclosure of probable and possible reserves, from the perspective of both an oil and gas company and an investor in an oil and gas company that chooses to provide such disclosure? Would investors be concerned by such disclosure? Would they understand the risks involved with probable of possible reserves?*

We continue to recommend that the reporting of reserves be limited to proved reserves only. However, the proposed optional reporting of probable and possible reserves is an acceptable alternative to mandatory reporting. We believe that investors would not be well served by the mandated inclusion of probable and possible reserves due to their increased uncertainty. We believe that most investors do not have a sufficient technical understanding of the industry and of the reserves estimation process to appropriately distinguish and appreciate the risks inherent in each category of reserves. We also believe the breadth of methodologies and evaluation techniques that may be employed in the calculation of probable and possible reserves will likely lead to a lack of consistency in industry reporting. We also strongly believe that the reporting of such reserves could expose companies to additional, unwarranted litigation due to their increased risk and uncertainty.

*Would the proposed disclosure requirements provide sufficient disclosure for investors to understand how companies classified their reserves? Should the proposed Item require more disclosure regarding the technologies used to establish certainty levels and assumptions made to determine the reserves estimates for each classification?*

*Should companies be required to provide risk factor disclosure regarding the relative uncertainty associated with the estimation of probable and possible reserves?*

As indicated in our previous response, we do not believe that most investors have a sufficient technical understanding of the industry and of the reserves estimation process to appropriately distinguish and appreciate the uncertainty inherent in each category of reserves. We do not think this can be addressed by extensive technical disclosures of the technologies used to support reserves estimates. We believe such a requirement will be impractical to implement since the recognition of reserves is typically based on the use of multiple technologies, data sources and interpretation methods and that such disclosures would be so complex and cumbersome to be of little value to even the most sophisticated investors.

*Should we allow filers to report sums of proved and probable reserves or sums of proved, probable, and possible reserves? Or, to avoid misleading investors,* *should we allow only disclosure of each category of reserves by itself and not in sum with others, as proposed?*

Given the different uncertainties inherent in each category of reserves, we think that summation of the reserves categories for disclosure purposes could be misleading to investors and should not be allowed.

*Should we require disclosure of probable or possible reserves estimates in a company's public filings if that company otherwise discloses such estimates outside of its filings?*

No, we strongly oppose such a requirement as it will defeat the objective of optional reporting. It will likely result in a reduction of industry information that is publicly available to financial statement users as we believe most companies will discontinue disclosures in non-filed documents (which is the current practice of many companies) to avoid the increased risk of litigation from mandatory reporting in filed documents. To avoid any confusion vis-à-vis other existing reporting requirements, we believe it would be very helpful for the staff to clarify in the final rule proposal that not using the option to report such reserves in documents filed with the Commission does not preclude companies from continuing to disclose such information in non-filed documents.

*Should we require all reported reserves to be simple arithmetic sums of all estimates, as proposed? Alternatively, should we allow probabilistic aggregation of reserves estimated probabilistically up to the company level? If we do so, will company reserves estimated and aggregated deterministically be comparable to company reserves estimated and aggregated probabilistically?*

We support the proposed aggregation of estimates as arithmetic sums at the lease, field or project level. We do not believe that segregation of reserves between those estimated probabilistically and those estimated deterministically is warranted since both estimating processes must meet the standard of reasonable certainty before reserves can be recognized. Segmentation of the data by estimating methodology will be burdensome to preparers and of limited value to most investors and financial statement users due to their lack of technical understanding of the industry and the reserves estimation process. When probabilistic methods are used, aggregation beyond the lease, field or project level up to the company level could yield very different results than if the deterministic results were aggregated.

*Should we revise the proposed form and content of the table? If so, how should we revise the table's form or content?*

With the exception of the proposed geographic segmentation (addressed below), we believe the form and content of the table is appropriate. However, as indicated previously, we believe that companies should be permitted the flexibility to present the required data and any supplemental data in a format that is most relevant and meaningful to its operations. The tabular formats should not be rigid specifications. This approach will be consistent with a principles-based disclosure system.

*Should we eliminate the current exception regarding the disclosure of estimates of resources in the context of an acquisition, merger, or consolidation if the company previously provided those estimates to a person that is offering to acquire, merge, or consolidate with the company or otherwise to acquire the company's securities? If so, would this create a significant imbalance in the disclosures being made to the possible acquirer, as opposed to the company's shareholders?*

We believe the current option for companies to disclose reserves estimates related to an acquisition, merger or consolidation should be retained as proposed. We believe this allows companies an option to keep shareholders appropriately informed about such transactions and not disadvantaged vis-à-vis the information provided to a possible acquirer.

### ii. Optional reserves sensitivity analysis table

*Should we adopt such an optional reserves sensitivity analysis table? Would such a table be beneficial to investors? Is such a table necessary or appropriate?*

We do not take exception to the proposed optional reserves sensitivity analysis table. However, we do not expect that we will avail ourselves of this option as we do not believe it is cost benefit justified. Calculation of reserves on multiple price bases would greatly expand the workload of our reserves estimators, who are already fully occupied with meeting the 60-day filing deadline for the Annual Report on Form 10-K.

*Should we require a sensitivity analysis if there has been a significant decline in prices at the end of the year? If so, should we specify a certain percentage decline that would trigger such disclosure?*

No, as noted above, we do not believe that such sensitivity analyses are cost benefit justified. We do not believe that they should be made mandatory under any circumstances.

*Should we revise the proposed form and content of the table? If so, how should we revise the table's form or content?*

We have no recommendations on the form and content of the table other than it remains an optional election for each company.

*As noted above in this release, SFAS 69 currently uses single-day, yearend prices to estimate reserves, while the reserves estimates in the proposed tables would be based on 12-month average year-end prices. If the FASB elects not to change its SFAS 69 disclosures to be based on 12-month average year-end prices, should we require reconciliation between the proposed Item 1202 disclosures and the SFAS 69 disclosures? What other means should we adopt to promote comparability between these disclosures?*

The potential outcome described in this question would be extremely costly and disappointing to the industry. From the standpoint that the FASB derives their authority to set accounting standards from the Commission, we encourage the staff to exercise leadership to ensure that the final rule proposal and the related financial accounting standards are conformed to establish a single consistent regulatory framework. We believe a dual reporting framework based on different price assumptions would be extremely costly to companies and confusing to financial statement users. We also believe such an outcome would be contrary to other Commission efforts underway to reduce the complexity of the U.S. financial reporting system.

A dual disclosure system would double the required amount of record keeping and reporting and would severely task our staff, systems and governance processes, which already are fully occupied with meeting the 60-day filing deadline for the Annual Report on Form 10-K. The complexity and cost of this outcome would be increased by a requirement to reconcile the proposed Item 1202 disclosures and the SFAS 69 disclosures.

### iii. Geographic specificity with respect to reserves disclosures

*Should we provide the proposed guidance about the level of specificity required when a company discloses its oil and gas reserves by "geographic area"?*

No, we do not believe that the proposed guidance is warranted and strongly recommend that the Commission retain the current approach specified in SFAS 69. We strongly recommend that the Commission avoid the use of bright line tests and requirements throughout the rule proposal as these almost always lead to unnecessary complexity and are inconsistent with a principles-based regime.

We believe the current requirement in SFAS 69 has worked well, i.e., that reserves be separately disclosed for a company's home country and for such "individual countries or groups of countries as appropriate for meaningful disclosure in the circumstances." We believe this is a principles-based approach that allows each company to determine what represents a "meaningful disclosure" based on a holistic assessment of their specific circumstances. This approach recognizes that geographic location is only one element among many considered in determining risks associated with particular resources. We believe additional segmentation, based solely on arbitrary percentages, will not provide meaningful benefits to financial statement users while increasing costs for preparers. More importantly, we believe the proposed segmentation poses competitive risks which we comment on further below.

We also note that, as proposed, the revised definition will have application far beyond the reporting of proved reserves. The same geographic splits will also apply to the following disclosures:

- Item 1204 – Oil and Gas Production
- Item 1205 – Drilling Activities
- Item 1206 – Present Activities
- Item 1207 – Delivery Commitments
- Item 1208 – Oil and Gas Properties, Wells, Operations and Acreage

As in the case of reserves, requiring disclosures based on fixed percentages within geographic areas, rather than relying on each company to determine the "meaningful disclosure in the circumstances" has the potential to significantly increase the complexity of data disclosed without any corresponding increase in the value of the information to financial statement users. For example, the geographic dispersion of data for the other disclosure items may be very different than for reserves, resulting in disclosures that are too granular in some areas or too aggregated in others. We recommend that the determination of geographic segmentation for these other disclosures also be left to management's judgment. Management can best decide the appropriate segmentation for each disclosure item, based on its knowledge of the business and assessment of the data distribution for each disclosure category.

*Are the proposed 15% and 10% thresholds appropriate? Should either, or both, of these percentages be different? For example, should both be 15%? Should both be 10%? Would 5% or 20% be a more appropriate threshold for either or both?*

As noted above, we recommend that the staff delete all such thresholds from the final rule proposal. To the extent the staff feels that the final rule must include some geographic thresholds, we recommend that they be limited to the country level. Mandated disclosure on the basis of sedimentary basin or field has the potential to result in inconsistent or incomparable disclosures due to differing, but well-founded, technical and legal definitions of each of those terms. Moreover, to the extent the additional geographic disclosure is intended to provide financial statement users with additional insight into potential non-technical risks associated with the particular reserves (e.g., political risk), that purpose is fully satisfied by a country by country disclosure.

Note that, in addition to the fact that information on a basin or field basis is unlikely to be effectively comparable or meaningful to an investor (as recognized by the staff's own questions below), the disclosure of such information has the potential to put the disclosing party at a significant competitive disadvantage vis-a-vis its competitors – particularly given the broad range of data to which this disclosure mandate might apply.

Consistent with our comments above, we believe the current principles-based system of geographic disclosure effectively serves the interest of both the disclosing company and the investment community. If additional disclosure on the basis of geography is mandated, we believe it should be limited to a country by country disclosure. With respect to such country by country disclosure, we recommend consideration of a high percentage threshold to ensure that the disclosure is, indeed, meaningful. For this reason, we recommend mandating disclosure only if reserves within a particular country exceed 20% of the registrant's global oil and gas reserves on an oil equivalent basis.

*What would be the impact to investors if companies are permitted to omit disclosures based on the individual field or basin due to concerns related to competitive sensitivities? Would investors be harmed if disclosure based on the individual field or basin is omitted due to concerns related to competitive sensitivities? Is there a better way to provide disclosure that a company heavily dependent on a particular field or basin may be subject to risks related to the concentration of its reserves?*

We do not believe investors will be harmed by the omission of disclosures based on the individual field or basin. To the contrary, we believe that giving companies the option to omit such disclosure protects shareholders from a potential loss in value of their investment due to the competitive damage that can be caused by such detailed disclosure. Consistent with a principle-based disclosure system, we think management is in the best position to determine the appropriate level of disclosure, balancing both the need for transparent, meaningful disclosure to prospective investors, while also protecting the economic interests of current shareholders. As stated previously, we believe that mandating specific disclosure thresholds is inappropriate and undermines management's ability to strike the appropriate balance between what are sometimes competing objectives.

As noted above, we believe that requiring basin or field level disclosures has the potential to put the disclosing party at a competitive disadvantage, particularly because the disclosure obligation is likely to extend well beyond proved reserves. Moreover, we believe that such competitive disadvantage may occur without any corresponding benefit to investors and other financial statement users – even ignoring potential issues regarding consistency and comparability arising from the definitions of "sedimentary basin" and/or field (both legally and technically) as applied in this context.

*Would greater specificity cause competitive harm? Is so, how can the rules mitigate the risk of harm?*

Yes, we believe greater specificity, particularly at the field or basin levels, can cause competitive harm. Such disclosures can undermine the negotiating positions of companies in future property sale transactions, unitization agreements or other asset transfers. Also, information about individual fields or basins is sensitive data that is often subject to restrictions by the national governments that have awarded the concession rights.

We believe that the current principles-based approach, requiring geographic disclosure to the extent such disclosure is, in fact, meaningful to investors or other financial statement users, best suits the needs of that community as well as preparers. Rigid bright line disclosure rules, that undermine management's ability to apply judgment, are contrary to this broad principles-based approach and undermine its strength.

*In the event that the FASB does not amend SFAS 69, should we require companies to supplement their SFAS 69 disclosure with greater geographic specificity? If the FASB does not amend SFAS 69, should we require that companies reconcile the differences between the reserves estimates shown in the SFAS 69 disclosure with the estimates presented in the proposed tables?*

As noted previously, we encourage the staff to exercise leadership to ensure that the final rule proposal and the related financial accounting standards are conformed to establish a single consistent regulatory framework. We believe a dual reporting framework and attendant requirements to reconcile differences would be extremely costly to companies and confusing to financial statement users. We also believe such an outcome would be contrary to other Commission efforts underway to reduce the complexity of the U.S. financial reporting system. We believe that the current rules regarding geographic disclosure are effective in serving the needs of investors and other financial statement users and should remain in place.

**iv. Separate disclosure of conventional and continuous accumulations**

*Should we require separate disclosure of conventional accumulations and continuous accumulations, as proposed?*

No, as stated previously, we do not believe that separate definitions of conventional and continuous accumulations are needed. We believe the disclosures should continue to be differentiated by end-product (i.e. oil and natural gas) rather than the type of accumulation. We recommend that the staff eliminate the proposed segmentation by conventional and continuous accumulations. We believe that the proposed disclosure, when coupled with other requirements in the rule proposal, will make the resulting disclosures so complex and granular as to reduce the informational content for financial statement users, while greatly increasing the cost and complexity of record keeping by preparers.

*Should we permit combining of columns if the product of the oil and gas producing activity is the same, such as natural gas, regardless of whether the reserves are in conventional or continuous accumulations?*

Yes, combining columns based on the end-product (oil or natural gas) will be better than having a separate column for each product based on the type of accumulation. Segmenting the reserves among so many parameters makes the resulting disclosures unwieldy, reduces the informational content for financial statement users and unnecessarily increases the cost and complexity of company record keeping.

For instance, assuming that the FASB does amend SFAS 69 to be in conformance with the final rule, the SFAS 69 proved reserves disclosures will need to follow the same product splits. This will result in several additional pages of SFAS 69 proved reserves disclosures. At least one page of disclosure will be needed for each of the products that a company may have from these various production methods, since each will require three years of data, with the change in each year due to revisions, improved recovery, extensions/discoveries, etc., split by the appropriate geographical segmentation and split between consolidated and equity companies. As a result, it will not be readily apparent what the total liquids and the total natural gas reserves for a company are and where they are reported, which are what most investors and other financial statement users want to know, not how they are produced.

### v. Preparation of reserves estimates or reserves audits

*Should we require companies to disclose whether the person primarily responsible for preparing reserves estimates or conducting reserves audits meets the specified qualification standards, as proposed? Should we, instead, simply require companies to disclose such a person's qualifications?*

*Should we require disclosure regarding a person's objectivity when a company prepares its reserves estimates in-house? Should the proposed disclosures regarding objectivity be required only if a company hires a third party to prepare its reserve estimates or conduct a reserves audit, as proposed?*

*If a company prepares its reserves estimates in-house, should we require disclosure of any procedures that the company has taken to preserve that person's objectivity? Should we require disclosure of whether the internal person meets specified objectivity criteria? For example, should we apply the some of the same criteria that we propose to apply to third party preparers? If so, which ones?*

*Consistent with the SPE's auditing guidance regarding internal auditors, should we require companies to disclose whether that person (1) is assigned to an internal-audit group which is (a) accountable to senior level management or the board of directors of the company and (b) separate and independent from the operating and investment decision making process of the company and (2) is granted complete and unrestricted freedom to report, to one or more principal executives or the board of directors, any substantive or procedural irregularities of which that person becomes aware?*

*Should we require disclosure with other specific independence or objectivity standards and, if so, what?*

*Should we revise any of the proposed provisions regarding a person's objectivity or technical qualifications? Should the proposal require disclosure of other criteria that would have bearing on determining whether the person is objective or qualified?*

*Should a company be required to present risk factor disclosure if its reserves estimates were not prepared by a person meeting the objectivity and technical qualifications?*

*Because of the inherent uncertainty regarding estimates of probable and possible reserves, should we require the proposed disclosure only if a company chooses to disclose probable or possible reserves?*

*Should we require that a third party prepare reserves estimates or conduct a reserves audit if a company chooses to disclose probable or possible reserves estimates?*

*Should we require the proposed disclosure only if the company is using technologies other than those which are allowed in our current definitions to establish levels of certainty?*

We believe that all of the proposed disclosures concerning the qualifications and objectivity of in-house and third party reserves estimators are inappropriate and impractical to implement.

We agree that the competency of reserve estimators is essential to ensuring that reported reserves are assessed and categorized according to generally accepted engineering and geoscience methodologies and that the assessments comply with regulatory requirements. Additionally, the internal control processes for management review and approval of reserves estimates should be robust and transparent.

However, we believe the proposed disclosures are so burdensome as to be impractical. The technical analyses required to arrive at a quality reserves assessment often require input from several disciplines and individuals. As a result, we have hundreds of personnel involved to some degree in the reserves estimation process around the world. Citing the qualifications of each employee will be burdensome and likely of little value or interest to an investor or financial statement user. Even a summary disclosure of qualifications will be daunting to develop, particularly considering the difference in educational systems, licensing and certification requirements and professional bodies from country to country. Lastly, the reserves disclosures are subject to the same internal control and management certification requirements as for the rest of the financial statements under Sarbanes-Oxley. We do not understand why the reserves estimation process should therefore be subject to what essentially amounts to a duplicative disclosure and certification process.

In lieu of detailed disclosures about individual qualifications, we recommend that the staff consider requiring an alternative disclosure describing the internal control systems applicable to the reserves estimation and reporting processes. This could include statements regarding the technical assessment routine, management review and approval processes and the internal audit process, as well as a summary description of the qualifications of typical reserves estimators. We believe this would be a more appropriate topic for discussion, would more broadly address the issues contemplated in the proposed disclosures from a management perspective and thus would be more consistent with the objectives of a principles-based disclosure system. If this is not an acceptable alternative, we recommend that, at a minimum, the staff clarify in the rule proposal that the proposed disclosures be limited to the chief technical person who oversees the company's overall reserves estimation process. In any event, we do not support mandatory licensing for any company personnel involved with reserves estimating.

**vi. Contents of third party preparer and reserves audit reports**

*Should we require a company to file reports from third party reserves preparers and reserves auditors containing the proposed disclosure when the company represents that a third party prepared its reserves estimates or conducted a reserves audit? As an alternative, should we not require that the third party's report be filed, but that the company must provide a description of the third party's report? If so, should we specify that the company's description of the third party's report should contain the information that we propose to require in the third party's report?*

*Should we specify the disclosures that need to be included in third party reports? If so, is the disclosure that we have proposed for the reserves estimate preparer's and reserves auditor's reports appropriate? Should these reports contain more or less information? If they should include more information, what* *other information should they include? If less, what proposed information is not necessary?*

*In an audit, should we specify the minimum percentage of reserves that should be examined and determined to be reasonable? If so, what should that percentage be? Should it be 50%, 75%, 90% or some other percentage? If so, why?*

*If the company engages multiple third parties to conduct reserves audits on different portions of its reserves, should the definition of reserves audit be conditioned on each third party evaluating at least 80% of the reserves covered by its reserves audit, as proposed? Is the scope of a reserves audit defined by geographic areas? If so, should the definition of a reserves audit be based on the third party's evaluation of 80% of the reserves located in the geographic areas covered by the reserves audit?*

*Would disclosure that a company has hired a third party to audit only a portion of its reserves be confusing to investors? Is there a danger that investors will not be able to ascertain the extent of the reserves audit? Should we require that a company could not disclose that it has conducted a reserves audit unless 80% of all of its reserves have been evaluated by a third party or, if the company hires multiple third parties, by all of the third parties collectively?*

*Is the proposed definition of "reserves audit" appropriate? Should we revise this proposed definition in any way?*

This area is not particularly significant to us since we make minimal use of third party assessments. When an outside assessment is obtained, it is normally because a financial institution has required it as a condition for providing capital to co-venturers. These assessments are prepared according to the requesting institution's guidelines, which could be, and apparently often are, inconsistent with the Commission's reporting requirements. As a result, these assessments normally play no role in supporting our reserves estimates in filed documents with the Commission. If a company elects to utilize third party assessors in preparing or auditing reserves statements, we believe the company has the same responsibility with respect to the third party as in the case of in-house estimators to ensure that the reserves estimates or audits are prepared in accordance with regulations and that the assessors are properly qualified and independent. However, we believe the disclosures contemplated in the rule proposal are excessive and will likely be of little value or interest to an investor or financial statement user. We believe our previous recommendation for an alternative disclosure describing the internal control systems applicable to the reserves estimation and reporting processes is very appropriate for this case. Companies could disclose that they are using third party estimators, to what extent and how they have modified their internal control processes. We believe this would be a more appropriate topic for discussion, would more broadly address the issues contemplated in the proposed disclosures from a management perspective and thus would be more consistent with a principles-based disclosure system.

### vii. Solicitation of comments on process reviews

*Should we require disclosure of whether a company has conducted a process review? Notwithstanding the relative lack of rigor of a process review compared to a reserves audit, would investors find such information useful?*

*The proposal does not prohibit disclosure of process review. Is there a danger that the public may be confused by such disclosure? Should we prohibit disclosure of any type of reserves-related activity other than the preparation of the reserves estimates or a reserves audit?*

We believe that periodic internal process reviews can be helpful in ensuring the adequacy and effectiveness of a company's reserves estimation process. However, we believe disclosure should be at the option of each company as currently proposed. Consistent with our previous recommendation for an alternative disclosure describing the internal control systems applicable to a company's reserves estimation and reporting processes, we believe this is another aspect that could be appropriately reflected in such a disclosure.

### 4. Proposed Item 1203 (Proved undeveloped reserves)

*Should we adopt the proposed table? Alternatively, should we simply require companies to reclassify their PUDs after five years?*

No, we recommend that the proposed table be deleted from the final rule. We also recommend no bright line requirements be introduced for PUD recognition or derecognition. As stated previously, we believe that the use of bright line tests and mandated disclosures should be avoided throughout the rule proposal as these almost always lead to unnecessary complexity and are inconsistent with a principles-based regime.

The aging and tracking of PUDs by their year of recognition and the tracking of related investment dollars would be a complex new reporting requirement that will necessitate costly changes to both accounting and reserves information systems. Given the increasing scale and term of industry development projects, we believe these disclosures will apply to an increasingly significant portion of reported reserves, further compounding the complexity of the proposed disclosures. Lastly, we believe these additional disclosures will be of limited incremental value to financial statement users in assessing a company's success in developing resources given the other multi-year production and proved reserves information already provided.

We also see definitional issues with the proposed disclosures. PUD investments can often span several calendar years as construction and installation of above ground facilities typically precede the final drilling efforts. The guidelines to the table presume that all of the investment dollars will be spent in the year of addition. This will be an infrequent occurrence. Accordingly the table will either need to reflect the multi-year dimension of PUD investments or it will need to consolidate multi-year investment dollars and associate them with the year that the PUDs were transferred to proved developed reserves. Either case will make the disclosure much more complex and difficult to implement and without further explanation will be confusing to investors and other financial statement users. Similarly the proposed disclosure will require companies to make many arbitrary investment cost allocations as some investments may support multiple tranches of PUDs that will be transferred to proved developed reserves over successive years. We also believe the proposed five-year time line for the table is inconsistent as all other reserves disclosures are reported on a three-year time frame.

We oppose reclassification of PUDs after 5 years, as this will unduly penalize companies who have taken on large, complex projects requiring extended development periods. As noted above, given the increasing scale and life of industry development projects, we believe the five-year reclassification restriction will apply to an increasingly significant portion of reported reserves. We understand the Commission's concerns in this area and agree that PUDs should be removed from proved reserves when there is no intent or capability by the company to develop them. However, derecognition based on an arbitrary time frame would be inconsistent with a principles-based disclosure system and could be confusing to investors and other financial statement users. As stated previously, we believe that the recognition of PUDs should continue to be based on management's comprehensive assessment of the geoscience, financial, commercial and operational aspects of each development project versus the standard of reasonable certainty. In the case of PUDs, recognition should particularly be dependent on management's firm commitment to develop the reserves over the project's anticipated time horizon.

*Should the table require disclosure of other categories of changes to the status of PUDs, such as acquisitions, removals, and production? Should we add any categories?*

No, these other categories will only add to the complexity and cost of the proposed disclosure and will provide no incremental benefits to investors or other financial statement users. The current disclosure requirements for proved reserves require a reconciliation of the changes in balances from the beginning to the end of each reporting period, including change categories for revisions, purchases, sales, improved recovery, extensions and discoveries and production. We believe these disclosures are more than adequate and do not need to be further broken down by PUDs and proved developed reserves.

*Some of the abuse related to PUD disclosure may be related to companies' desire to show proved reserves in light of our prohibition on disclosure of probable reserves. Would the proposed rules permitting disclosure of probable reserves reduce the incentive to categorize reserves as PUDs? If so, is the proposed table necessary?*

We are not familiar with the referenced abuses in PUD disclosures. Accordingly, we have no basis to determine if the disclosure of probable reserves will reduce such abuse and to what degree.

*Should we require disclosure of the reasons for maintaining PUDs that have been classified as PUDs for more than five years, as proposed? If not, why not?*

No, we do not think this disclosure should be required. As noted above, we believe this requirement will apply to an increasingly significant portion of reported reserves, further expanding the complexity of the proposed disclosures. Again, we strongly believe that the use of bright line tests and mandated disclosures should be avoided throughout the rule proposal as these almost always lead to unnecessary complexity and are inconsistent with a principles-based regime. We believe this arbitrary five-year requirement could lead investors and other financial statement users to the incorrect conclusion that the disclosing company lacks the commitment or capability to develop such reserves, when it is merely a reflection of the nature of large-scale, complex projects. We also believe that this disclosure could force companies to disclose potentially sensitive competitive data as we believe the circumstances driving a longer than five-year development time frame could differ by field or basin. For example, if development of a major project for a particular field exceeded five years, the detailed disclosures proposed could give competitors insight into a company's marketing plans and sales strategies. Competitors could use this information to direct competing supply into the intended market threatening existing contractual sales arrangements, sales prices realizations and the access to and cost of infrastructure.

*Should we require a company to disclose its plans to develop PUDs and to further develop proved oil and gas reserves, as proposed? If not, why not?*

*Should we require the company to discuss any material changes to PUDs that are disclosed in the table? If not, why not?*

In lieu of the proposed table, we recommend an alternative requirement to disclose the quantity of company PUDs, the progress that the company made during the year in converting them to proved developed reserves and material PUD changes that occurred during the year. We suggest this information be disclosed with the proved oil and gas reserve quantities table required by SFAS 69, "Disclosures about Oil and Gas Producing Activities." We believe this approach will be more consistent with a principles-based approach and of more value to financial statement users.

### 5. Proposed Item 1204 (Oil and gas production)

*Should we adopt the proposed table?*

The proposed table is acceptable with two exceptions: 1) the requirement to split revenue and costs between conventional accumulations (e.g., oil and gas) and continuous accumulations (e.g., bitumen), and 2) the requirement to split production costs between oil, gas, and any other product. Concerning the first point, as noted above, we believe that disclosures which split reporting between conventional and continuous accumulations provide minimal value to investors. In regards to the second point, oil and gas production is often commingled in well bores and splitting common costs between flow streams can be an arbitrary allocation. If there is a desire to show production costs on a unit of production basis, the measure should be costs per total barrel of oil equivalent, i.e., total production costs divided by total production with gas being converted into an oil equivalent using a standard measure (e.g., six thousand cubic feet of gas = 1 barrel).

*Should the disclosure be made based on the proposed definition of "geographic area," or should we continue to follow the definition set forth in SFAS 69?*

The disclosure should be made based on the applicable definition of "geographic area." As noted above, we believe the lowest appropriate geographic denominator is the country level. We strongly recommend consistency be maintained with the geographic aggregations being used for the SFAS 69 disclosures.

*Should we eliminate the instructions listed above, as proposed? If not, which instructions should we retain? Please explain why those instructions continue to be useful*.

We recommend retaining the instructions on the use of marketable gas and the calculation of average production costs to help ensure the disclosure is being prepared on a consistent basis between companies. The marketable gas definition provides clarity on the difference in volume streams for this calculation versus the one used for the proved reserve table (e.g., gas consumed in field operations or flared). The average production cost definition is important information to the investor since this calculation excludes depreciation and depletion costs and all taxes.

### 6. Proposed Item 1205 (Drilling and other exploratory and development activities)

*Should we adopt the proposed table? Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?*

No, we believe the proposed table increases the granularity and complexity of well disclosures, does not provide useful, relevant information to financial statement users and is therefore not cost benefit justified. We believe the table as proposed will confuse investors, particularly in the suspended well area.

Given advances in drilling technology, which have reduced the need for the number of wells to develop a specific field versus past practices, we question whether the drill well tables are presenting an accurate picture to investors of a company's actual development activity over time. Given the need for fewer wells, a tabular, numeric comparison of well counts over time likely presents a misleading indicator of actual field development activity to investors, diminishing any value that it provides. We also believe that disclosure of "any other exploratory or development activities conducted" in the past three years is already covered in the existing Form 10-K disclosure requirements covering the "Review of Principal Ongoing Activities in Key Areas." If the proposed disclosures were made, we believe they should be done on the same "geographic area" used in proposed item 1201(d).

*Should we require separate disclosure about the two new proposed categories of wells—extension wells and suspended wells? Does distinguishing these types of wells from exploratory wells and dry wells provide enough clarity regarding the types of exploratory or development activities?*

We do not support separate disclosure of the two new proposed categories of wells, namely extension wells and suspended wells. If extension wells were to be reported, additional clarity is needed in the definition to emphasize that these wells are a subset of the exploratory well category. The new requirement to further segregate the exploratory well category between those wells testing for "new sources of oil and gas" versus those wells that are "merely the extension of an existing field" is a distinction that will require much more specific rule-making by the staff before it could be consistently applied in practice. We believe the proposed inclusion of suspended wells in the table is particularly problematic. The definition of a suspended well in this table is a well which has been drilled but not completed. The company may do additional work in the future (e.g., the well is not being abandoned nor called dry or successful). In contrast, a suspended well, as defined in SFAS 19-1, is an exploratory well which finds reserves but those reserves cannot be classified as proved when drilling is completed. SFAS 19-1 requires an extensive set of disclosures on these wells. We believe the proposed table, which uses a different suspended well definition than SFAS 19-1, will be very confusing to investors. It is also unclear how individual wells will migrate to and from this category over time. We believe the table as currently defined will also result in a single well bore being counted twice if it was "suspended"; once in the year the well was drilled and again in the year the well was completed. We question the need for this additional segmentation as we do not believe there are a significant number of wells which have been drilled, but then suspended prior to completion. If a company has such a well, and it is material to its operations, scope already exists in the current MD&A to disclose this activity.

### 7. Proposed Item 1206 (Present activities)

*Should the disclosure of present activities be made based on the definition of "geographic area" in proposed Item 1201(d)?*

The disclosure of present activities should be based on the proposed definition of "geographic area," provided the lowest denominator is the country level.
*Should we adopt any other changes to the disclosures currently set forth in existing Item 7 of Industry Guide 2 that we propose to codify in Item 1206?*

No, we do not believe any other changes are needed. We recommend that the current guidance requiring disclosure of only specific operations that are material to a company's operation be retained.

### 8. Proposed Item 1207 (Delivery commitments)

*Are the proposed revisions appropriate? Do the proposed revisions make any unintended substantive changes to the existing disclosures?*

The proposed revisions are acceptable and we do not believe they make any unintended substantive changes to the existing disclosures.

*Should we adopt any substantive changes to the disclosures currently set forth in Item 8 of Industry Guide 2 that we propose to codify in Item 1207?*

No, we do not believe any substantive changes are needed to the disclosures in Item 8 of Industry Guide 2.

*Is this disclosure requirement still necessary? Do oil and gas companies still enter into such delivery commitments? Are they material?*

We do not believe this disclosure is still necessary. Most companies that have delivery commitments also have "force majeure" clauses in those contracts which limit a company's liability in the event reservoir performance falls below expectations.

## 9. Proposed Item 1208 (Oil and gas properties, wells, operations, and acreage)

### i. Enhanced description of properties disclosure requirement

*Are the proposed disclosure enhancements regarding oil and gas properties appropriate? Would this enhanced disclosure be helpful to investors?*

We do not support the proposed disclosure enhancements. We believe the existing broad guidelines in Item 102 of Regulation S-K are appropriate and allow management the flexibility to decide the appropriate level of disclosure based on their knowledge of the business and the materiality of each operation. We believe further expansion of the extensive information already provided under item 102 will be of minimal incremental benefit to investors and will not justify the related costs.

*Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?*

If the disclosures are required, they should be based on the definition of "geographic area" as proposed in item 1201(d), provided that the lowest geographic denominator is the country level and that it is consistent with the geographic aggregations used for SFAS 69 disclosures.

*Do we need to define any of the terms in the proposed language?*

The definitions in the proposed language are adequate.

### ii. Wells and acreage

*Is the proposed table appropriate? Is there a better way to disclose such information?*

We do not believe that disclosure of well and acreage information is particularly meaningful information to investors and other financial statement users, and rather than expanding the current disclosure requirements, we believe they should be left unchanged.

However, if required, the proposed table for wells is appropriate, but splitting out wells associated with other products should not be required. As detailed in earlier responses, disclosures should be based on the end product (i.e. oil or gas) rather than by the nature by which the volumes are extracted.

If required, the proposed acreage table is appropriate. However, added disclosure around areas such as expiring undeveloped acreage, in many instances will adversely impact a company's competitive position and should not be required.

*Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?*

The disclosures should be based on the definition of "geographic area" in proposed item 1201(d), provided the lowest geographic denominator is the country level and is consistent with the geographic aggregations used in the SFAS 69 disclosures.

*Is it necessary to disclose wells and acreage in conventional accumulations separate from wells and acreage in continuous accumulations, as proposed?*

As noted previously, we do not support splitting the wells and acreage disclosures by conventional accumulations and continuous accumulations. We believe this split will be of limited value to financial statement users.

*Is this disclosure requirement still necessary? Is disclosure of the number of wells and acreage material? Should we require the disclosures related to wells and acreage only if there is a high concentration of production or reserves attributable to a few wells or limited acreage? If so, should we specify what that concentration would be?*

As noted previously, we do not believe that disclosure of wells and acreage data is meaningful information to investors. If required, we are supportive of retaining the present disclosures without adding additional detail such as new well categories or splitting disclosures between conventional and continuous accumulations.

**iii. New proposed disclosures regarding extraction techniques and acreage**

*Should we require more specific disclosure regarding extraction activities that do not involve wells? Should this proposed item remain open-ended to permit description of unanticipated technologies?*

We believe that the current level of disclosure already provided in the required discussion of Business Activities and MD&A is sufficient and provides meaningful information to the investor. We do not believe that there should be specific additional requirements for extraction activities not involving wells. We recommend that this disclosure requirement remain open-ended and registrants have flexibility to describe new or enhancements to existing technologies.

*Is the proposed disclosure for unproved properties appropriate? Should the proposed disclosure for unproved properties be set forth in proposed Item 1208?*

*Should we move such disclosure to the reserves table in proposed Item 1202, where reserves are discussed?*

We believe that the proposed additional disclosure requirements for unproved properties are excessive and are not appropriate if a registrant chooses not to optionally report reserves related to unproved properties.

**10. Proposed Item 1209 (Discussion and analysis for registrants engaged in oil and gas activities)**

*Proposed Item 1209 is not intended to increase a company's disclosure requirements, but specify disclosures already required generally by MD&A. Is such an item helpful?*

*Are the proposed topics that an oil and gas company should consider discussing as part of MD&A, whether in the main MD&A section or in conjunction with the relevant table, appropriate? Are there other topics that an oil and gas company should consider discussing?*

*Should we permit such discussions in conjunction with the relevant table as proposed? Would this aid comparability of the disclosures? Or should we keep MD&A as a self-contained section?*

We view this as a new and expanded MD&A disclosure requirement since it specifies a number of detailed disclosure items which are not referenced elsewhere in any of the Commission's guidelines. Many of the requested disclosures are at such a detailed level (for example, discussion of the performance of individual producing wells, including water production and the need to use enhanced recovery techniques) that they will not provide meaningful or relevant information to a financial statement user. Also, some of the new MD&A requirements are complex and costly to implement (for example, the disclosure of anticipated capital expenditures to convert PUDs to proved reserves will be a complex new reporting requirement that will require changes to both accounting and reserves information systems). In addition, several of the disclosures could cause competitive harm to the disclosing company (for example, anticipated exploratory activities, well drilling and production; anticipated capital investment in PUDs; remaining terms of leases and concessions; prices and costs data). We recommend that the staff delete these new disclosures or, alternatively, limit the list of potential disclosures to items that could be material to an investor.

We also note that some of the requested discussion on changes in proved reserves overlaps with requirements found in SFAS 69. We think this is a good example of an area where it will be helpful for the staff to work with the FASB to align the rule proposal with the related accounting standards to minimize the complexity of the resulting regulatory system.

To the extent that some of the proposed additional disclosures are ultimately required, we believe it will be more appropriate for them to be displayed in conjunction with the relevant tables.

## IV. Proposed Conforming Changes to Form 20-F

We are not directly affected by the rules applicable to foreign private issuers, however, we appreciate the opportunity to comment on the proposed conforming changes.

We agree with the staff's statement that the rule changes will promote more consistent and comparable disclosures among oil and gas companies. We believe establishing a "level playing field" in this regard benefits investors and other financial statement users as well as companies required to make the disclosures. We also believe that it is consistent with establishing a principles-based disclosure system.

*Should we delete Appendix A and refer to Subpart 1200 with respect to Form 20-F, as proposed? Why? Should we expand the requirements of Form 20-F to require more disclosure than currently required by Appendix A, as proposed? Conversely, should we only update Appendix A to reflect the proposed new definitions and formats for disclosing reserves and production?*

As noted above, we believe that the proposed expansion of the requirements of Form 20-F to require more disclosure than currently required by Appendix A is consistent with and will promote the Commission's overall goal of enhancing disclosure consistency and comparability. We likewise find it an appropriate modification that is consistent with establishing a principles-based disclosure system. While updating Appendix A solely to reflect the proposed new definitions and disclosure format would seem to be the minimum change that could be implemented, we believe adopting the more expansive approach proposed helps to "level the playing field" for all companies in the industry.

*Would the proposed reference to Subpart 1200 in Form 20-F significantly change the information currently disclosed by foreign private issuers? If so how? Would such a change be appropriate?*

We believe this will likely increase the amount of information disclosed by foreign private issuers but we believe this is appropriate for the reasons stated above.

*Is the proposed exception for foreign laws that prohibit disclosure about reserves and agreements appropriate? Do such laws affect domestic companies as well? Should Subpart 1200 have a general instruction with respect to such foreign laws?*

Given the global nature of the industry, both domestic (U.S.) and foreign-based companies have the potential to have operations in jurisdictions that preclude disclosure of reserves and agreements. Consequently, a single approach to the issue applicable to all companies would be appropriate and consistent with the stated goals of improving the consistency and comparability of company disclosures. To avoid ambiguity, we suggest that guidance on foreign laws be incorporated into a general instruction for Subpart 1200. We believe this guidance should indicate that if required information is not disclosed because a foreign government *affirmatively* restricts the disclosure of estimated reserves for properties under its governmental authority, or amounts under long-term supply, purchase, or similar agreements subject to its governmental authority, the registrant should disclose the country, cite the law or regulation which restricts such disclosure, and indicate that the reported reserves estimates do not include amounts for the named country.

*Are the proposed revisions to Instructions to Item 4.D appropriate with respect to foreign private issuers that have extractive activities other than oil and gas producing activities?*

Similar to our position on Item 1208 (iii), we believe that the current level of disclosure provided in the required discussion of Business Activities and MD&A is sufficient and provides meaningful information to the investor. We do not believe that there should be specific additional requirements for extraction activities not involving wells. We recommend that this disclosure requirement remain open-ended and that registrants have flexibility to describe new technologies or enhancements to existing technologies.

## V. Impact of Proposed Amendments on Accounting Literature

### B. Change in Accounting Principle or Estimate

*Are the proposed changes more properly characterized as a change in accounting principle or a change in estimate under SFAS 154?*

We believe the proposed changes are properly characterized as a change in estimate under SFAS 154 and should be accounted for on a prospective basis.

*Would it be appropriate to consider the changes as a change in accounting principle, but specify that no retroactive revision of past years would be required?*

We do not believe it would be appropriate to consider the changes as a change in accounting principle even if there was no retroactive revision of prior years.

*If we required retroactive revision of past years, would companies have the historical engineering and scientific data to make such revisions? If not, are there alternatives to retroactive revision that we should consider?*

Retroactive revisions of prior year's reserves and financial data would require a very significant effort with minimal benefit to an investor. We believe most companies will have the technical data needed for a restatement of prior years, but could not justify the significant effort required for such a project since the changes to both the financial statements and reserve tables would most likely be immaterial.

### C. Differing Capitalization Thresholds Between Mining Activities and Oil and Gas Producing Activities

*How should we address these inconsistencies between oil and gas accounting rules and mining accounting rules?*

*Should we permit companies that extract, through mining methods, materials from which oil and gas can be produced to continue to capitalize costs under mining rules, or should we require them to capitalize costs based on oil and gas rules? Are there circumstances involved with mining operations, different from oil and gas operations, that justify capitalization of costs of proved plus probable reserves, as opposed to only costs of proved reserves?*

We believe that the accounting and disclosures for operations that extract oil and gas through mining methods should be conformed to the SFAS 19 accounting methodology for oil and gas activities. We do not believe this will create material changes in accounting results on transition or thereafter. We believe that getting these resources on a consistent accounting and disclosure methodology with conventional oil and gas activities will improve the consistency and comparability of financial reporting. Similar to previous comments, we believe that all accounting and disclosures should focus and be aligned on the basis of the product that is produced rather than the extraction method utilized to produce the product.

### D. Price Used to Determine Proved Reserves for Purposes of Capitalizing Costs

*Would the effect of such changes be material or have a material effect on historical amortization levels?*

*Would the effect of such changes be material or have a material effect on comparability? Please provide any empirical evidence to support your conclusion.*

*Would it be appropriate to continue to require the use of the year-end price for purposes of determining reserves for purposes of amortization expense while using a different price for purposes of disclosing reserves estimates in Commission filings? This would result in a different value associated with the use of the term "proved reserves" for purposes of disclosure, as opposed to the use* *of that term for purposes of accounting. Would this be confusing? Should we use a different term? Should we otherwise clarify the two different meanings of that term in different contexts?*

We strongly recommend that the proved reserve quantities included in disclosures and used for SFAS 19 accounting purposes be based on the same 12-month average prices. The use of two pricing bases will sever the link between the required disclosures and the related financial accounting which is not consistent with an effective and transparent reporting model. The maintenance of such a "two-price" system will be unduly costly and burdensome for registrants, and it will likely confuse financial statement users such that additional disclosures might be required to explain the differences.

In view of the typical relationship between the amount of proved reserves and the attendant volume of production during any one accounting period, we believe it is unlikely that any changes to reserve quantities used for depreciation purposes to reflect year-average prices will have a significant impact on a company's reported amortization expense. To the contrary, the use of average prices will reduce the magnitude of changes that may otherwise be caused by large fluctuations in year-end prices. In any event, we do not think that depreciation expense based on single-day, year-end prices yields a conceptually better accounting result than one based on average prices.

## VI. Impact of the Proposed Codification of Industry Guide 2 on Other Industry Guides

*Is it appropriate to codify Industry Guide 2 separately from the other industry guides? Should we merely amend Industry Guide 2 and codify it with all of the other industry guides when they have been updated?*

We support the proposed codification of Industry Guide 2 as part of the current rule making exercise.

*Would the codification of Industry Guide 2 overrule or otherwise affect any of the disclosures required in the other Industry Guides?*

We are not affected by the other Industry Guides, but we do not believe the proposed codification will unduly affect them.

## VII. Solicitation of Comment Regarding the Application of Interactive Data Format to Oil and Gas Disclosures

*Should we adopt rules that require oil and gas disclosures to be provided in interactive data format? Instead of requiring such formatting, should we only permit the filing of oil and gas disclosures in interactive data format? What are the principal factors that we should consider in making these decisions?*

We believe that the oil and gas disclosures ultimately should be provided in the XBRL interactive data format, consistent with the Commission's current proposal for the rest of the financial statements. However, we do not believe that XBRL reporting should be mandated for the first year of implementation (i.e. for the 2009 Form 10-K). We expect that most industry companies will be challenged in the base case with completing implementation of the new rule proposal, without also having to deal with an XBRL reporting requirement. We recommend that the Commission consider a phased-in implementation, where no XBRL reporting will be required in the first year of implementation (2009 Form 10-K), block tagging in the second year (2010 Form 10-K) and full tagging of all elements in the third year (2011 Form 10-K). We believe this phased-in implementation will be consistent with the Commission's current proposed XBRL implementation approach and schedule for the rest of the financial statements. It will also provide companies the opportunity to develop some experience with the new disclosure requirements prior to implementing them in XBRL.

*If we require oil and gas disclosures to be filed in interactive data format, should we provide for a voluntary phase-in period to create a well-developed standard list of electronic tags? Without a requirement, would the development of products for using interactive data meet the needs of investors, analysts, and others who seek to use interactive data? Would a large percentage of oil and gas companies provide interactive data voluntarily and follow the same standard, if not required to do so?*

Consistent with the above response, we believe that XBRL reporting of the new disclosures should not be required any earlier than for the 2010 Form 10-K. We have no basis to estimate what percentage of oil and gas companies will or will not provide data interactively if not required to do so.

*Would investors, analysts, and others find presentation of oil and gas disclosures helpful if presented in interactive data format? In what ways would such users of the information find such a format beneficial?*

It is currently unclear to us whether investors, the financial analyst community and other financial statement users will find XBRL reporting beneficial, or whether they will even attempt to use it.

*As we note above, there is not currently a well-developed standard list of electronic tags for the oil and gas disclosures. Are there any obstacles to creating a useful standard list of electronic tags for the oil and gas disclosures? Is the type of data presented in the proposed table conducive to interactive data format? Would it be particularly difficult to create standard electronic tags for any of the proposed data? Would there be any obstacles to providing comparable data in interactive format?*

As we are in the initial phase of implementing the XBRL standard and its functionalities, we do not yet have the needed perspective and experience to effectively answer these questions. However, we anticipate that it will take some time to get the electronic tags perfected for industry use, particularly considering the extensive nature of the required disclosures currently included in the rule proposal.

*Would it be useful for the data in the proposed tables to interact with other data in Commission filings? If so, which data?*

As we are in the initial phase of implementing the XBRL standard and its functionalities, we do not yet have the needed perspective and experience to effectively answer these questions.

*If we adopt rules requiring oil and gas disclosures in interactive data format, should we require the use of the eXtensible Business Reporting Language (XBRL) standard? Are any other standards becoming more widely used or otherwise superior to XBRL? What would the advantages of any such other standards be over XBRL?*

To the extent that an interactive data format is required, we believe the XBRL standard should be used since this will be the method used for the rest of the financial statements. We do not believe that it will be efficient or practical for preparers or financial statement users to deal with multiple standards.

## VIII. Proposed Implementation Date

*Should we provide a delayed compliance date, as proposed above? If so, is the proposed date appropriate? Should we provide more or less time for companies to familiarize themselves with the proposed amendments?*

Yes, we believe the proposed implementation date is appropriate. The rule proposal in its current form will require a substantial implementation effort by ExxonMobil that will span the better part of a calendar year. If the issuance of the final rule proposal should be delayed into 2009, we believe the Commission will need to consider a delay of the effective date.

*If we provide a delayed compliance date, should we permit early adoption by companies?*

No, we do not believe early adoption should be allowed. We believe that the implementation date should be kept consistent for all companies to maintain a level playing field and to avoid the potential for investor confusion that may result from the use of differing reporting methodologies during the transition period.

## X. Paperwork Reduction Act

*We request comment in order to evaluate the accuracy of our estimate of the burden of the collections of information. Any member of the public may direct to us any comments concerning the accuracy of these burden estimates. Persons who desire to submit comments on the collection of information requirements should direct their comments to the OMB, Attention: Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Washington DC 20503, and should send a copy of the comments to Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549-1090, with reference to File No. S7-15-08. Requests for materials submitted to the OMB by us with regard to this collection of information should be in writing, refer to File No. S7-15-08, and be submitted to the Securities and Exchange Commission, Records Management Branch, 100 F Street NE, Washington, DC 20549-1110. Because OMB is required to make a decision concerning the collections of information between 30 and 60 days after publication, your comments are best assured of having their full effect if OMB receives them within 30 days of publication.*

## XI. Cost-Benefit Analysis

*We request comment on all aspects of the Cost-Benefit Analysis, including identification of any additional costs or benefits of, or suggested alternatives to, the proposed amendments. We also request that those submitting comments provide, to the extent possible, empirical data and other factual support for their views.*

## XII. Consideration of Burden on Competition and Promotion of Efficiency, Competition, and Capital Formation

*We request comment on whether the proposals, if adopted, would promote efficiency, competition, and capital formation or have an impact or burden on competition. Commenters are requested to provide empirical data and other factual support for their views, if possible.*

We offer the following comments in response to the questions in Sections X, XI and XII above.

We are concerned about the extensive new disclosure requirements included in the proposal, most of which were not discussed in the Concept Release. Cumulatively, the new disclosures will necessitate a significant implementation and training effort. For example, many of the proposed disclosures require a degree of granularity not currently present in our reporting and consolidation processes. This will necessitate costly changes to these systems. We believe data disclosures that go beyond what companies use to manage the business on a day to day basis are inherently excessive. The cost-benefit analysis section of the proposal estimates that the new rules will require an incremental effort of 35 hours per registrant. We believe this is significantly understated and that for ExxonMobil the incremental effort could be as high as 15,000 to 20,000 hours. More importantly, we believe some of the proposed disclosures are of little value to financial statement users, do not justify the high implementation costs and can cause competitive damage to the disclosing company in some instances. These disclosures will likely make the U.S. financial markets and U.S. oil and gas companies less competitive internationally and are inconsistent with recent Commission efforts to reduce the complexity of the U.S. reporting system.

## **Other Comments**

### Need to Clarify Approach to the Reporting of Equity Company Reserves

The rule proposal is silent on the treatment of equity company reserves and other related information. It appears no differentiation is made between consolidated subsidiaries and equity companies and that only the combined total is to be reported for each disclosure item. We strongly support this combined reporting approach and recommend that the final rules make this explicit. We believe that separate disclosure of consolidated subsidiaries and equity companies, as required in the existing guidelines, has been confusing to financial statement users. We believe an approach that fully integrates equity company data into each disclosure will improve the clarity and the quality of disclosures, particularly since companies view the economic value and importance of equity company reserves and related activities to be equal to those of consolidated subsidiaries. We note this may require an amendment to the examples in SFAS 69. The examples in SFAS 69 do not expressly prohibit the addition of reserves quantities for consolidated companies and equity affiliates, but the staff in comment letters has interpreted the examples to prohibit such arithmetic addition. Alternatively, the staff could withdraw their previous interpretations to allow the full integration of equity company data as we have proposed.

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# Reserve Overbooking - The Problem No One Wants to Talk About

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## Abstract

Managers of publicly held companies often face pressures that can tempt even the most principled to push the envelope of credibility in efforts to buoy investor confidence and thus increase stock value. In an age of instant gratification and inflated expectations of return on equity, companies often struggle with long range strategic planning while at the same time striving to meet expectations of the next quarterly earnings report. The quest for increased market capitalization often leads these harried managers to look under every stone for anything that will entice more investors to buy into their company.

The assets of oil and gas companies consist mostly of hydrocarbons in the ground – reserves. In typical annual reports one often finds proved oil and gas reserves stated in very precise terms. These reserve numbers are, in reality, very imprecise because of the variability and uncertainty in the earth and in the industrial and economic world. This is why the industry is moving increasingly away from deterministic reserve estimates to probabilistic, or stochastic, reserve estimates. Ironically, it is the very uncertainty associated with reserves that has enabled and preserved a practice that has, over the last twenty years, destroyed value and led many investors down the primrose path – reserve overbooking.

Reserve overbooking occurs for many reasons, among them poor estimating practices, misguided incentives, ignorance, competition for investors, and lack of professionalism. Any temporary benefits companies may derive from overstating reserves disappear whenever reserves must be de-booked. The resulting loss of confidence by investors and analysts is often made more painful by the fact that it could have been avoided. Reserve overbooking is a problem that may be solved through consistent, professional reserve estimating and reporting, and leadership, professionalism and accountability by informed and knowledgeable managers.

## Introduction

"I appreciate your courage." "Now why do you want to go stir up that hornet's nest?" "I hope you know what you are fixin' to get yourself into!" These are just some of the comments uttered at the very mention of a public discussion of the problem of reserve overbooking. It seems that, while many people recognize the problem, and a courageous few have raised the issue in this and other professional societies, it remains a subject few want to openly talk about – a taboo. One reason, perhaps, is a belief that if "we wait long enough, the problem will either go away, or at least be something someone else has to deal with."

One of the sobering realities of the upstream oil and gas industry is the level of uncertainty associated with hydrocarbon reserves – the significant part of the industry asset base. Much has been written in the literature[1,2,3] about reserve estimating and there appears to be widening acceptance of the superiority of probabilistic versus deterministic reserve estimates particularly for exploration prospects. However, our nature as human beings leads us to think we are smarter than we actually are[4]. Add to this the bias that comes from a variety of motivational forces (**Tables 1 and 2**)[5,6] coupled with reserve definitions that leave much room for acknowledged subjectivity and you have an environment that can encourage reserve overbooking.

As noted by Ross[7] the SPE and WPC took a great step forward in dealing with this issue by publishing a set of comprehensive reserve definitions[8]. With respect to what remains to be done within the industry Ross further states, "unless the regulatory bodies also adopt these definitions and guidelines or improve their existing ones, major inconsistencies will remain a significant problem for the industry." But the effectiveness of even the best of guidelines depends upon the knowledge and professionalism of the users. It is these issues that the authors hope to address in this paper.

## The Problem with Reserve Overbooking

Those of us responsible for reserve stewardship, either as technical staff or management, act as agents for the shareholder of the company, whether it is a sole proprietor or the owner of stock in a publicly held corporation. We are not in the business of finding and producing oil and gas; we are in the business of making money, or adding value, for the shareholders. In our case it is through the efficient and economic exploration for and exploitation of hydrocarbons. When reserves are overbooked, either intentionally or out of ignorance, it not only misleads shareholders, it can and has led to the destruction of shareholder value. Market and financial analysts are not fools. They have the skills and tools to sift through the details of company financial reports to see what is going on behind the scenes. Many companies no longer exist, in part due to the impact of what they might have termed "aggressive" reserve booking. Any benefits derived from such practices, whether perceived or tangible, quickly evaporate whenever reserves are de-booked. When people realize that, to paraphrase the well-known fable, 'the company has no reserves', the shareholders are the ones who pay the price.

Overbooking also creates stress and tension within organizations because the pressures to aggressively book reserves conflict with a natural tendency towards engineering conservatism and (to admittedly varying degrees) a sense of prudence that comes with professionalism. An environment that encourages such aggressiveness often fosters intense internal competition for resources, people and bonuses, to the detriment of the organization's ability to compete in the market place.

## The Causes of Reserve Overbooking

In light of the negative consequences of overbooking, the fact that it persists in spite of increasing awareness reveals just how strong the forces causing it are. These forces are not limited to companies within the United States. For example, in a study of Canadian companies, Jung[9] observed that in any given year there is a 40% probability that a company will debook oil reserves and a 60% probability of debooking gas reserves.

Overbooking can occur throughout the life cycle of an asset.

- Exploration
- Mergers and Acquisitions
- Development Drilling
- Stimulation Workovers
- Improved/Enhanced Oil Recovery

In our work with more than 30 companies ranging from large multi-national companies to privately held independent producers we have identified the following factors contributing to reserve overbooking.

### Poor Estimating Practices and Ignorance

These are the so-called errors of omission – purely unintentional. Given the extent of literature that discusses sound, systematic reserve estimating procedures we have little excuse for the use of outdated or incorrect methods, even in innocence. Companies that persist in making deterministic reserve estimates run the risk of overestimating reserves, particularly when trying to get exploration deals approved. A single, deterministic estimate, often classified "most likely", is possible (assuming it falls somewhere on a probabilistic reserve distribution), usually optimistic and nearly always wrong. In such a system an intrepid engineering and geologic team strive to put together the best estimate they can, considering their experience and interpretation of the data. They then present their "most likely" case to their boss, who proceeds to tell them to try again because it is not the answer he or she was looking for. The term "most likely" is part of the problem because it means different things to different people. Anyone who has suffered under this scenario should appreciate the power of probabilistic reserve estimates as well as the statistically consistent terms (e.g. P90, P50, P10, Mean) used to describe them.

Because it is so subjective, the term "most likely" can make it easy to justify aggressive reserve booking. So also can the term "reasonably certain" which is used in the United States Security and Exchange Commission's definition of proved reserves[10].

***Examples***

1. *Development Drilling* – Big Rock Oil Company has decided to decrease the well spacing in a tight gas field in the western United States thereby significantly increasing both reserves and daily production. Early results were so good they accelerated the drilling schedule and booked 2 bcfg per well based on early decline curve analysis. Only after an engineering study (requested by another working interest owner a year later) did they discover that many of the wells were in fact taking production from existing wells. Instead of 2 bcfg per well, the average reserves per well were estimated to be 1.25 bcfg. Would you debook now, or hope that the wells perform better than estimated?

2. *Development Drilling* – Blue Moon Production Company began development of a new gas field it had recently discovered in Oklahoma. The initial well test was inconclusive with respect to drainage radius. Offset fields were developed on 160-acre spacing so Blue Moon booked reserved based on 160-acre drainage. Four years later, Blue Moon hired a new reservoir engineer who began to look at reservoir performance. She reviewed subsequent well test data, which included making P/z plots, and determined that the average drainage area was approximately 100 acres per well. Should Blue Moon debook reserves now?

3. *Stimulation Workover* – RCM Oil and Gas operates several leases in the middle of a field that has proved to be a major disappointment – to its own investors and to the industry in

general. In hopes of increasing field recovery, RCM spent two years working with a stimulation company to develop a new hydraulic fracturing process. Results from the stimulation program, which not only increased production two and three-fold but also reduced the decline rate, exceeded RCM's expectations. Accordingly they doubled the booked reserves for their leases. Good news being hard to contain, however, offset operators jumped on the bandwagon and began stimulating wells all around RCM's acreage. As they did, RCM began to notice an alarming decrease in production rates, and a corresponding increase in decline rates in most of their wells. While the program was indeed successful, a staff study estimated that it only added between 50% and 65% to the field EUR – significantly below the 100% increase RCM had booked. Should RCM debook now? If not, when should they?

**Misguided Incentives and Competition for Investors**

One of life's truisms is "what gets rewarded gets done." In most companies, management sets the tone for the behaviors it wants to create by the incentives it establishes. So why do companies often get what they do not want? It is quite simple; people will do what they perceive will either give them pleasure or avoid pain. For example, let's assume that Big Rock Oil's staff receives a bonus for getting wells drilled. Further they are told that if they get less than five wells drilled over the next two years they will be laid off. Now what results should management expect? They should expect to see a lot of wells brought forth! But will those wells create value? This may or may not matter to the staff – they received their bonus. But it sure matters to the shareholders.

From late 1998 through 1999, stock markets, particularly in the US, experienced dramatic increases in prices. Regardless of whether or not some of the star market performers had the business results to justify their stock price, investors began to expect returns in excess of 30%. For the oil and gas industry, this presented a troubling question: How do you compete in this kind of market? Managers found themselves (or perceived themselves to be) caught between increased pressure from investors and analysts, and the reality of actual market performance. Marko[10] studied the shareholder returns of more than 30 publicly held companies and found that only one company performed better than the Standard and Poor's 500 Index in the time period from 1995 through 1999.

***Examples***

4. *Corporate Operations* – One day, Stan, Doug and Julie were in Doug's office discussing the results of a new workover program. As they were meeting, they heard the voice of their manager bellowing from somewhere outside the office. Swinging a piece of 7/8-inch sucker rod in his hand, he walked slowly down the hall as he shouted, "Okay ladies and gentlemen. It's time for reserve adds. I want more reserves!" "Hey boss, what's up?" asked Julie. Their manager replied that headquarters had sent a call to all of the divisions telling them to find more reserves to book. It turned out that they were behind the reserve replacement targets that corporate management had given to the investment community. When they asked more questions, Stan, Doug and Julie were told, "Be aggressive; we can always debook later!" In this case, part of the Management's bonus compensation came from meeting published goals. The staff received no bonus, but was being severely pressed (they all noticed the piece of sucker rod) to add reserves. The question is, for whose benefit? Certainly not for theirs, and certainly not the shareholders.

5. *Corporate Merger* – Dry Sand Resources announced plans to merge with Big Rock Oil. As is often the case, the corporate staff had two weeks in which to perform a due diligence assessment. When they presented the results to Management the staff expressed concerns about reserves in some of Big Rock's western gas fields. They were told not to worry about it, since prices were holding steady and management expected them to remain strong for at least the next two years. Besides, Dry Sand needed this deal in order to be able to meet its annual growth projections. So, the deal was done, and Dry Sand indeed met its growth target, even if it came with a bit more debt than they had hoped.

   The next year, however turned out to be much warmer than expected, and gas prices, especially in the western US, plummeted. About the same time, Dry Sand's engineering staff was becoming increasingly concerned about sharp production declines in some of the gas fields they had acquired from Big Rock. It became clear that the fields were overbooked by as much as 20%. Management now had a real dilemma on their hands. They were already in a cash crunch, due to falling prices. What's more, that "a bit more debt than they had hoped" was now looming with interest payments consuming much of their available cash. Debooking reserves would increase the company's depletion, depreciation and amortization (DD&A), which could lead to downgrading of the company stock by the analysts. What would you do at this point? Go ahead and debook to the appropriate reserve level and accept the consequences, or do nothing and hope for the best?

**A Brief Look at Corporate Accounting**

One day Dilbert, cartoonist Scott Adams' often bemused protagonist, found himself transferred to the accounting department of his company. During his "orientation" he was told that while many people believe numbers to reflect reality, they (the accounting department) took the view that numbers "create reality." While most of us get a good laugh from such humor, it does illustrate the potential for corporate accounting to encourage practices such as reserve overbooking (or at least discourage debooking).

Under accounting systems used by most companies accumulated capital costs are depreciated as a function of reserves, or on a unit of production (UOP) basis. As mentioned in one of the above examples, DD&A (expressed in \$/boe or \$/mcfe in the United States) is an important corporate financial measure. Since debooking reserves increases DD&A, companies with high DD&A rates are often reluctant to do so. This becomes a real challenge for managers, especially when part of their compensation is tied to corporate financial performance.

Some cases of reserve overbooking have been associated with – even blamed on – changes in corporate accounting methods; such as from Full Cost accounting to Successful Efforts accounting. Generally, however, we believe that the real culprit lies not in the accounting method, or even the change from one method to another, but rather accounting manipulations for the purposes of maximizing various tax provisions, which may become liabilities under a different accounting system. In any case, the solution lies in thorough interaction of reservoir engineering, economics, accounting conventions and the appropriate tax codes, so that such problems may be anticipated and accommodated.

Related problems can sometimes occur when a company leaves a large numbers of wells suspended, thus temporarily avoiding reserve write-offs. As a general rule, companies that place excessive importance upon net income, as a measure of success, may tend to encourage such accounting practices.

## The Solution – How to Avoid Reserve Overbooking

The preceding examples of reserve overbooking were drawn from dozens of examples from across the industry. In each case, the consequences of overbooking, which are often financially and personally painful, could have easily been avoided.

Clearly, not all companies overbook reserves, and not all that have overbooked have done so intentionally. But regardless of whether overbooking occurs, for whatever reason, or not, the forces that encourage overbooking surround all of us. So, what can be done? Fortunately the solution, while potentially challenging, is a straightforward combination of leadership, education and professionalism.

**Leadership**

As with most human organizations, companies tend to go where the leadership takes them. So the solution begins with a management committed to removing bias from the company portfolio and to implementing and enforcing a consistent, systematic process for estimating and booking reserves with a focus on adding value to the shareholder. Once management makes this commitment it must communicate it throughout the organization: lead by example, provide clear direction, responsibility and accountability – and "walk the talk."

Management must also take a hard and serious look at the company's incentive and reward system. Remembering that people generally do what they are rewarded for doing, managers can then objectively evaluate current incentive systems by asking some questions such as:

- "Am I getting the results I think I am rewarding?"
- "If we are not getting the results we want, how are we rewarding what we are getting?"
- "Are we rewarding bias or objectivity?"

Any system that encourages internal competition should be challenged. A guiding principle to consider is, "If the company prospers, we all prosper."

***Example***

6. *Company Success versus "Division" Success* – Bill and Jack are divisional vice-presidents for their company. Each of them has been allocated staff and money for the following budget year. In many companies, Bill and Jack would be competing with each other for these resources and the commensurate prestige that goes with having responsibility for the most people and dollars. However, they work for a company that is focused on adding value for the shareholders, which Bill and Jack both are. By prioritizing the annual portfolio based on adding value regardless of division, resources can be shifted as opportunities present themselves. Because the company's reward system is based on the entire company's success, Bill has no qualms about moving people and money to Jack's division when it has better opportunities. Instead of competing with each other, their organizations together are competing with other companies.

**Education and Professionalism**

Changing past conventions about reserve estimating requires us to learn some new concepts and procedures. It may also require us to adopt some different organizational mores, to be willing to look at past results and consider that there may be better ways of doing things.

It has been said that practice makes perfect. Honest and thoughtful reflection, however, leads to the realization that practice does not make perfect, it makes permanent. It is evaluated practice that allows us to move toward real improvement (since perfection is unattainable).

We can, for example, through reading and study become completely familiar with how to fly any airplane. We can be thoroughly versed on the physics of heavier-than-air flight, understand that lift is a function of a pressure differential created by airflow across the wing, and understand how to manipulate the aircraft controls to cause an airplane to pitch, yaw and roll. But none of us would step foot into an airplane piloted by someone who had not had many hours of evaluated flight time. Why should shareholders expect anything less when it comes to estimating reserves?

Reserve estimating is serious business. Educating ourselves involves more than learning how to become systematic and consistent in estimating reserves by:

- Understanding the uncertainty found in nature and honoring nature's envelopes.
- Understanding how bias affects our estimating and decision-making.
- Learning how probability and statistics, the language of uncertainty, can help us improve our estimates.

Education, as we use the word here, also includes being willing to look at past performance, not for the purposes of finding someone to blame, but to learn from both mistakes and successes to improve future estimates. This is one of the attributes that mark a true professional.

Professionalism is a reflection of character and personal ethics. It is a product of knowledge, skill and expertise, guided by values and principle rather than circumstances. Being a professional is not limited to technical staff, just as leadership is not limited to management.

Being professional will encourage us to:

- Accept responsibility for improving our estimates and measuring our performance
- Resist the pressure to knowingly overstate reserves
- Guide decision-makers to making better informed decisions
- Accept accountability for our estimates and decisions
- Remember that ethical behavior transcends culture and generations
- Place shareholder value above personal gain.
- Be fair and objective.

***Example***

7. *Making it Work* – Bob and Susan had spent several weeks on a team working an exploration project in a promising new basin. In fact, the new Exploration Vice President had spent several years working this area in a previous job. During their presentation to the VP, Bob and Susan thoroughly described the prospect and fielded a variety of questions focused primarily on the potential reserves distribution. The VP, under pressure to improve the company's exploration performance, pressed the team to come up with a higher reserve estimate. Bob and Susan had worked this prospect hard, and had developed a probabilistic estimate using a systematic process that included review by knowledgeable peers and an analysis of their own company's past performance. Thus, Bob and Susan were able to communicate, confidently and tactfully, to the VP that while the number he wanted was possible, there was only a 15% probability of finding that reserve level or more, given discovery. Being committed to professionalism allowed Bob and Susan to resist the pressure to arbitrarily increase their estimate; and having asked appropriate questions, allowed the VP to accept and support the recommendations of the staff.

We believe that reserve overbooking will rarely occur:

- In a company whose management is:
  - Committed to leadership
  - Informed and knowledgeable
  - Accountable
- In a company committed to:
  - Professionalism
  - Removing bias from its estimates
  - Educating and training its management and staff on proper estimating procedures and systematic reserve estimating
  - Holding management and staff accountable for estimates and results

## Conclusion

The subject of reserve overbooking is, in many aspects, a sensitive one. We have by no means given an exhaustive examination of the topic. We have, however, sought to sound a wake-up call, to stimulate open discussion and debate within the industry about improving the credibility of reserve bookings. We, as a profession, have both the knowledge and tools available to us to eliminate, or at least significantly reduce reserve overbooking. We, as professionals, have an obligation to our shareholders to strive for nothing less.

## Nomenclature

| | | |
|---|---|---|
| *bcfg* | = | *billions of standard* $ft^3$ *of gas* |
| *boe* | = | *barrels of oil equivalent* |
| *mcfe* | = | *thousands of standard* $ft^3$ *equivalent* |

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## SI Metric Conversion Factors

| | | | | |
|---|---|---|---|---|
| acre | x | 4.046 873 | E+ 03 | = $m^2$ |
| bbl/d | x | 1.589 973 | E - 01 | = $m^3/d$ |
| $ft^3$ | x | 2.831 865 | E - 02 | = $m^3$ |
| $ft^3/d$ | x | 2.831 865 | E-02 | = $m^3/d$ |

**Table 1- Biases Affecting Judgment Under Uncertainty (modified after Rose, 1987)**

| Type of Bias | Common Example |
|---|---|
| Overconfidence | Predictive ranges are too narrow, indicating that estimators are much less accurate than they think they are. |
| Representativeness | Analog based on small sample size may not be statistically significant; chosen analog may not be analogous. |
| Availability | Recent or spectacular examples are more prone to be cited, regardless of their real frequency in nature; limited imagination limits number of possible interpretations. |
| Anchoring | In estimating, a low starting point leads to a lower final estimate, and a higher starting point leads to a higher final estimate. |
| Unrecognized Limits | Engineers and geologists forecasting future reserves may disregard non-geologic factors |
| Motivation | Prospectors exaggerate magnitude of reserves or chance of success in order to sell the deal |
| Conservation | Technical staff may feel that overestimating a project is worse than underestimating it, therefore “err on the safe side”. |

**Table 2 – Biases Affecting Risk Decisions (modified after Tversky and Kahnemann, 1974)**

| Type of Bias | Common Example |
|---|---|
| Framing Effects | Decision makers will take a greater gamble to avoid a loss than to make an equal gain. |
| Existence of a prior account | Decision makers are more inclined to take a risk at the beginning of a project than later in the project’s life. |
| Maintaining a consistent frame of reference | Decision makers are more likely to invest during a “run” of good fortune, and less likely to invest during a “run” of bad fortune. |
| Probability of success | A venture having a perceived high chance of success is preferred over a second venture having a low chance of success, even though the expected value of the second venture is clearly superior. |
| Wrong action versus inaction | Managers prefer to take a risk by not making a decision, rather than taking action that could result in some loss. |
| Number of people making the decision | Groups are more prone to take risks than are individuals. |
| Workload and venture size | Large-volume ventures are preferred over smaller ones, especially when decision makers are busy. |
| Personal familiarity | The “comfort bias” – decision makers are more risk-prone in deals or environments with which they have good experience. |