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Evaluating Production Potential of Mature US Oil, Gas Shale Plays

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US oil supply has been on an unprecedented surge of 1.3 million b/d, from an all time historical low of 4.95 million b/d in 2008. Current production of crude oil is 6.3 million b/d, the highest level since 1997, and is expected to increase another 370,000 b/d in 2013. This exceptional growth in output was triggered mainly by major breakthroughs in production technology for tight oil resources headed by the Bakken, Eagle Ford, and Niobrara plays, **Fig. 1.** As recently as five years ago, we learned to efficiently drill horizontal wells with laterals as long as 8 miles and complete them with as many as 40 hydraulic fracs. This modern technology has shaped a mega transformation in the US oil and gas industry. US natural gas supply has gone from a status of shortage to abundance.

We can now access vast oil and natural gas resources that we have known to exist for decades but were impossible to recover because of their very low permeabilities (in the micro-darcy range for tight oil, and nanodarcy range for shale gas) and porosities that are a fraction of those of conventional reservoirs. By comparison, good conventional oil and gas reservoirs in the onshore US have permeabilities of 1-100 md and porosities of 10-15%.

Historically, horizontal drilling technology got its start in tight gas sands in the 1980s, subsequently moving into the almost impermeable (akin to concrete) shale gas plays at the end of the 1990s. Specifically, the Barnett was the first shale gas play to be commercially developed. Modern horizontal drilling coupled with multistage fracing only began in the mid-2000s, and by 2008 there were 12,000 producing wells in the Barnett, of which two-thirds were horizontal and one-third vertical.

US marketed gas production was at a low of 46 bcf/day in September of 2005 when shale gas output was only 1.4 bcfd. Since then, gas production has grown to 66 bcfd in 2011, and shale gas to about 20 bcfd, headed by the Haynesville (5.9 bcfd), Barnett (5.6 bcfd), and Fayetteville (3.0 bcfd), the three most developed of the shale gas plays. US consumption of gas is about 94% of domestic production so supply is not as dependent on foreign producers, as is the case for oil. The availability of large quantities of shale gas should enable the US to consume a predominantly domestic supply of gas for many years and produce more natural gas than it consumes. The EIA's *Annual Energy Outlook 2012* projects US gas production to increase to 76 bcfd in 2035. Almost all of this increase is due to projected growth in shale gas production, to 37 bcfd by 2035.

Fig. 1 US Shale Plays. There are 22 major shale basins located in more than 20 states.

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI. Updated: May 9, 2011.

On the US domestic crude oil front, the author's recent stochastic outlook (Sandrea, 2012) indicates an upside output of 7.7 million b/d by 2025, of which half would come from tight oil plays. When potential output from NGLs – mainly from shale gas plays – is factored in, total US liquids supply could reach 16 million b/d from 10 million b/d today.

Implicit in these upside scenarios for both oil and natural gas are several constraints of diverse nature, from environmental to policy issues, along with many technical challenges. This paper addresses some of the major technical issues that affect estimates of two key parameters: the volume of recoverable oil or gas, and its production potential, which ultimately determine the value of the asset. Both factors are physically interrelated, and are indispensable for the planning of field infrastructure and take-away capacity. They depend critically on field performance which is sparse given the short production history – barely 10 years – of shale plays. Last summer, for example, the USGS (2011) sharply cut back the technically recoverable natural gas reserves of the Marcellus play to 84 tcf from 410 tcf. The EIA subsequently upped it to 141 tcf in its 2012 Outlook. Production from the Marcellus barely started in 2008. In the past three years there have been similar fluctuations in recoverable oil and gas for several of the major shale plays.

An intrinsic characteristic of all shale plays is their extremely high initial decline rates (63% per year and more) with steep trends, a combination that is conducive to significant decreases in the recovery factor and a shorter economic field life. As a result, in the short production history of shale oil and gas there are already three mature plays: Barnett, Fayetteville, and Bakken (Elm Coulee). A thorough evaluation of their ample performance history will provide useful analogs for the many emerging plays. This is the main goal of this study.

Assessing US Shale Gas

Shale Gas Basics

Shale gas is natural gas that never migrated but remained trapped in the original source rock, adsorbed in the insoluble organic matter. Gas shales are therefore both the source rock and the reservoir for the natural gas. They are characterized by ultralow permeabilities and the micro pore spaces can barely accommodate the flow of tiny methane molecules. Gas production from hydraulically fractured shale is believed to come from both desorption and diffusion within the fracture network, in contrast to Darcy flow in conventional reservoirs. The mechanisms are still far from clear.

This complexity is why shale gas was the last major source of unconventionals (the others being tight gas and CBMs) to be developed. Shale gas production in effect took off in the mid-2000s, essentially after modern horizontal drilling and multistage fracing technology became widespread. And the Barnett was the pioneering shale play. Produced shale gas is generally dry – less than 50 million barrels (mb) of NGLs per tcf – although several plays have a liquid content of up to 125 mb/tcf, termed a rich gas. The Barnett shale gas averages 87% methane with a liquid content of 83 mb/tcf while the Fayetteville, Haynesville, and Marcellus have average methane contents of 87%, 95%, and 85%, respectively.

Shale gas resources are spread all over the US (**Fig.1**), at depths varying between 1,000 feet and 13,500 feet. They are *continuous*, covering millions of acres, in contrast to discretely dispersed conventional oil and gas fields. A good shale gas prospect has a thickness between 300 and 600 feet. The five largest shale gas plays in the US are the Marcellus, Haynesville, Barnett, Woodford, and Fayetteville, with technically recoverable gas varying from 84 tcf for the Marcellus to 5 tcf for the Fayetteville. **Table 1** summarizes the general attributes of these major shale gas plays.

The EIA (2012) estimates that the US holds 3.7 quadrillion cubic feet (qcf) of shale gas in-place of which 482 tcf are considered technically recoverable; barely 24 tcf have been produced so far. Worldwide, shale gas activity is still very low. Potential resources, excluding those in the US, are estimated by the EIA at roughly 5.6 qcf.

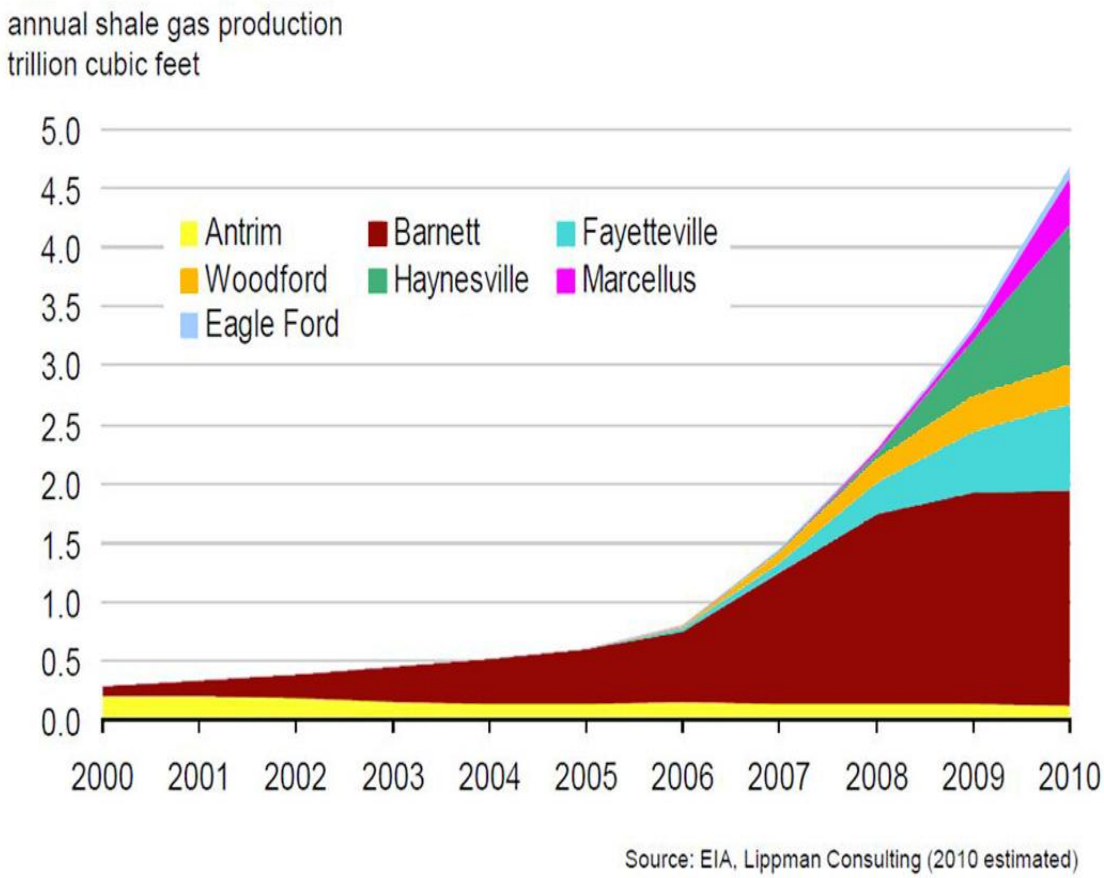


Table 1 Attributes of Five Major US Shale Gas Plays - 2011						
Plays	**Barnett**	**Fayetteville**	**Haynesville**	**Marcellus**	**Woodford**	**All US Plays**
Production Start-up	1998	2006	2008	2008	2006	
Original Gas in-Place, tcf	327	52	717	1,500	150	3,764
Area, sq. miles	6,500	9,000	9,300	94,000	3,000	
Depth, feet	5,000-8,000	1,000-7,000	9,600-13,500	4,000-8,500	6.000-11,000	
Thickness, feet	100-500	20-200	200-300	50-200	120-220	
Well Spacing, wells/sq. mile	6	8	8	8	4	
Output, bcfd	5.30	2.45	4.23	1.5	1.1	20
Cumulative Production, bcf	10.8	2.2	1.9	1.0	1.2	24
Estimated Recoverable Gas, tcf	**19***	**5***	**34**	**84**	**10**	**482**
Recovery Factor, %	**5.8***	**10***	**4.7**	**5.6**	**6.6**	**13**
Estimated Production Potential, bcfd	**5.5****	**3.0****	**10**	**26**	**2.7**	
Avg. Well EUR, bcf/well	1.3	1.1	3.0	1.2	3.0	
Avg. Well Costs, $million	3.5	2.8	9.5	6.0	7.0	
Notes: bcfd = billion cubic feet/day; tcf = trillion cubic feet of gas. Estimated recoverable gas = unproven technically recoverable gas. * value was established by decline analysis; ** field values. Recovery factor = recoverable gas/gas-in-place; Estimated production potential is calculated with Equation (2). 640 acres = 1 square mile.						
Sources: EIA2012, USGS2010, Producer estimates, and several other sources cited in References.						

Decline Analysis

The Barnett and Fayetteville are the only shale gas plays with sufficient production history to allow a comprehensive field decline analysis. Production from each of these two plays has reached a volume roughly equivalent to the half-life of their recoverable reserves. Classical logistic decline analysis indicates *proven* ultimate reserves (EUR) of 19 tcf for the Barnett and 5 tcf for the Fayetteville. The comparable estimates of *technically* recoverable reserves, according to the recent EIA/AEO2012 report, are 26 tcf and 13 tcf, respectively.

Shale gas plays show unusually high field decline rates with very steep trends, a combination conducive to low EUR values, and consequently low recovery efficiencies. **Fig. 2** gives a matchstick look at decline rate trends for the Barnett and Fayetteville, and for Hugoton, the largest conventional gas field in the US. The values shown on the graph refer to the last three years of production. The contrast between shale gas plays and conventional fields is astounding. Keep in mind that extrapolating the decline rate trendline to rate = 0 gives the corresponding

EUR value for the play. The steeper the trend, the smaller the EUR value and, consequently, the lower the recovery efficiency. Backward extrapolation of the trendline to the start of production (cumulative production = 0) gives the initial decline rate for the play and all are evidently very high.

The abnormally high decline rates for shale gas have been recorded in producing wells from the very onset of field development. Recovery efficiencies calculated with these new decline EUR values for the Barnett and Fayetteville are 5.8% and 10%, respectively; this contrasts significantly with recovery efficiencies of 75-80% for conventional gas fields.

Table 2 gives initial well rates and first-year decline rates for large data sets of wells in the five major shale plays, as reported by Standard & Poor's Creditweek/December 14, 2011. In general, average first-year well decline rates vary from 63% to 86% while initial well rates vary from 2.0 million cubic feet per day (MMscf/d) for the Barnett to 9.5 MMscf/d for the Haynesville. About 75 percent of well EUR for the Barnett is produced by Year 5. Most wells have a commercial life of less than 15 years while EUR values refer to a 30-year life span.

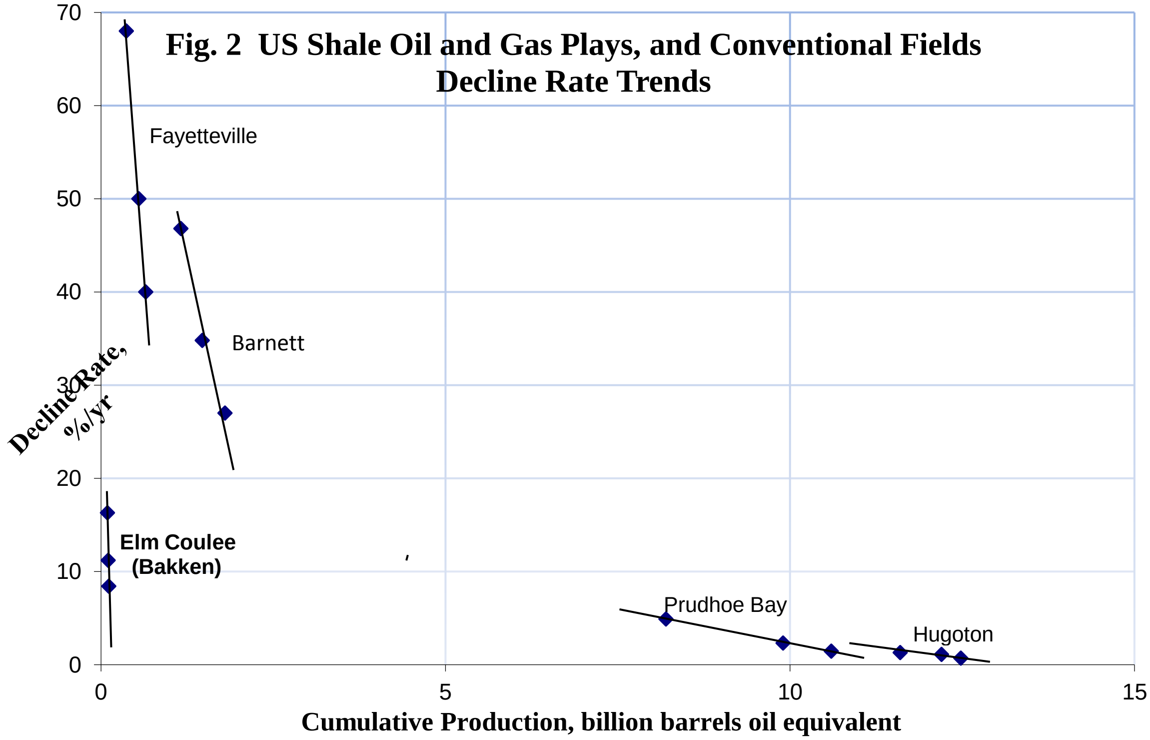
The Haynesville is a unique shale play with extremely abnormal high initial well rates – about 3 times the average initial well rates of the four other major plays, with recorded well rates as high as 30 MMscf/d – and abnormally high first-year well decline rates, 86%! This is a consequence of the fact that the Haynesville, the deepest of the major plays, is highly overpressured with pressure gradients in the range of 0.75-0.85 psi/ft. By comparison, pressure gradients for the Barnett and Fayetteville are more in the range of 0.52 psi/ft. A normal field gradient is about 0.43 psi/ft. All considered, the recovery efficiency of the Haynesville is a low 4.7%.

The recovery efficiency for the five major plays averages 6.5%, and ranges from 4.7% to 10%, **Table 1.** The EIA's estimate for all plays is 13% or nearly double. This would suggest that their estimate of 482 tcf of recoverable gas for the US should at best be 240 tcf based on present information. It is worth mentioning that the USGS estimates of oil and gas in-place for the different shale plays have proven to be dependable over time, the movable parameter being the recoverable oil and gas that defines recovery efficiency.

Table 2 Initial Well Rates and First-Year Well Decline Rates
Shale Gas Plays

	Initial Well Rates, MMscf/d	**Early Well Decline Rates, %/year**
Barnett	2.0	70
Fayetteville	2.5	63
Haynesville	9.5	86
Marcellus	4.5	75
Woodford	3.5	80

Notes: MMscf/d = million cubic feet per day
Source: Standard & Poor's CreditWeek, Dec. 14, 2011

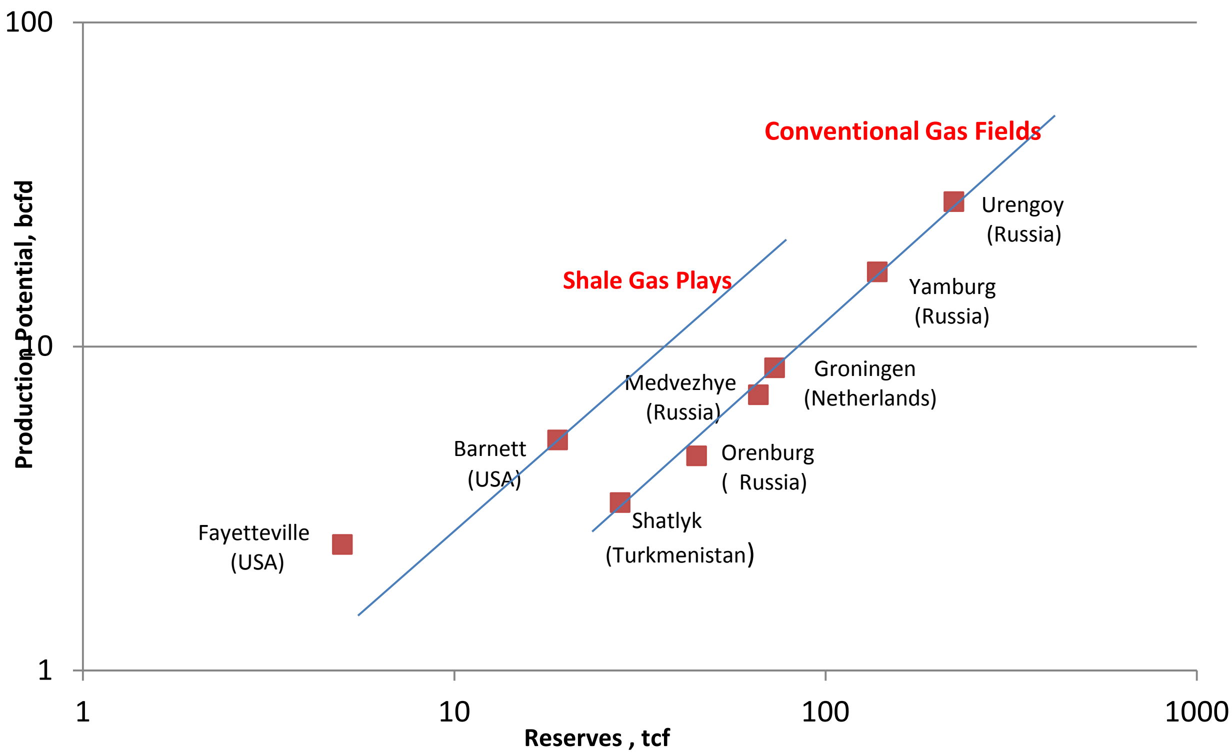


Production Potential

It is a firmly established principle that reserves are the foundation of production potential and they follow a power law relationship (Sandrea 2006, 2009). **Fig. 3** shows the correlation of these two parameters for six conventional giant gas fields around the world.

Fig. 3 Production Potential and Reserves

Gas Fields



Superposed on the graph are values for the Barnett and Fayetteville shale plays, the only two plays with adequate field data at this time. The shale gas plays are evidently not conventional; their behavior indicates that their high peak production rates do not translate into a bigger (more reserves) field. By hypothesis, the shale gas plays should follow a similar power law relationship but parallel to that of the conventionals. We drew the trend line weighting the much larger Barnett. We would have to wait for data from future mature shale gas plays to fine-tune the specific trend. But it's a good jumping-off point.

The relationship for *shale gas plays* is:

$$q_{peak} = 0.23\ K^{1.0664} \qquad (1)$$

where q_{peak} is the production potential of the play with units of bcfd, and K is the size (reserves) of the play in tcf. This algorithm was used to estimate the production potential of the plays in **Table 1,** based on the current estimates of recoverable gas. Estimates of production potential are for the Marcellus 26 bcfd, the Haynesville 10 bcfd, and the Woodford 2.7 bcfd.

The equivalent relationship for *conventional* gas fields is:

$$q_{peak} = 0.087\ K^{1.0664} \qquad (2)$$

This shows that shale gas plays peak at rates 2.6 times those of conventional gas fields, for the same size field. The similar exponents in both algorithms reflect the assumed parallel nature of the relationships. The correlation coefficient (r^2) for Equation 2 is 0.994.

Assessing US Tight Oil Plays

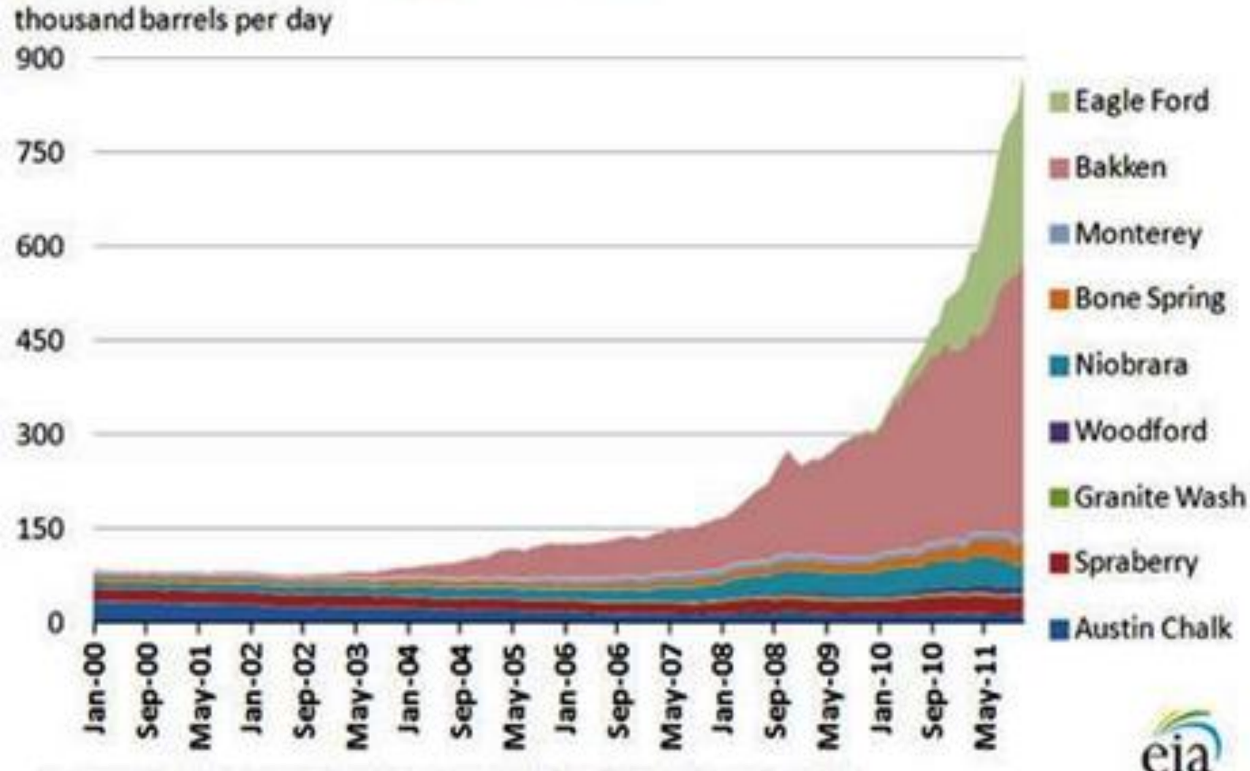
Tight Oil Basics

The Bakken has been the torch bearer of the shale oil revolution following the success of modern extraction technology applied to shale gas. It is the largest commercial *continuous* oil accumulation in the world and currently accounts for almost two-thirds of all US shale oil production. The Bakken, Eagle Ford, and Niobrara, are the three leading shale oil plays with 91% of total US shale oil output. These shale oil plays are now more commonly referred to as tight oil plays. In contrast to shale gas, which remained trapped in the original shale source rock, the Bakken, for instance, contains migrated oil trapped in siltstone and sandstone between layers of shale. The Eagle Ford's oil is trapped in carbonate rocks overlying the Eagle Ford shale from which it migrated. Hence there is an important distinction (with shale gas) that affects the reservoir dynamics. In general, tight oil reservoirs are in close contact with their shale source, and induced fractures most likely extend into the shale providing some of the produced oil.

Tight oil reservoirs have higher permeabilities and porosities than their shale gas counterparts, in the range of 40 microdarcys with porosities around 5%, respectively. They are located at depths varying from 1,000 to 14,000 feet, with thicknesses from 10 to 3,000 feet. **Table 3** summarizes the attributes of the top six major tight oil plays in the US. Avalon and Bone Spring are two small plays with the Avalon sitting atop the Bone Spring Formation. They are combined into a single unit in this study for lack of separate published data.

The EIA in 2012 estimated that the US holds 33 billion barrels of technically recoverable tight oil. The six major plays account for 31 billion barrels, or 93% of the whole. Production history of tight oil plays starts in the early 2000s and is very limited; barely 585 million barrels have been produced so far from a national resource base estimated to hold over 3.5 trillion barrels. Likewise, worldwide activity can at best be described as embryonic.

Figure 2. Tight oil production for selected plays



Source: U.S. Energy Information Administration based on HPDI, LLC; 2011 is through November

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Table 3 Attributes of Five Major US Tight Oil Plays - 2011							
Plays	**Elm Coulee**	**Bakken**	**Eagle Ford**	**Niobrara**	**Avalon & Bone Spring**	**Monterey**	**All US Plays**
Production Start-up	2000	2000	2008	2010	2009	2009	
Original Oil in-Place, Bbo	2.3	413	300	500	130	500	3,500
Area, sq. miles	450	6,520	2,200	20,300	1,310	1,750	
Depth, feet	8,500-10,500	3,100-11,000	2,500-15,000	3,000-14,000	6,000-13,000	8,000-14,000	
Thickness, feet	10-45	75-130	50-350	200-400	900-1,700	1,000-3,000	
Well Spacing, wells/sq. mile	2	2	5	8	4	12	
Output, b/d	24,000	375,000	125,000	32,000	22,000	10,000	620,000
Cumulative Production, Bbo	0.113	0.43	0.06	0.03	-	-	0.59
Estimated Recoverable Oil, Bbo	**0.13***	**5**	**3**	**7**	**1.6**	**14**	**33**
Recovery Factor, %	**5.6***	**1.2**	**1.0**	**1.4**	**1.2**	**2.8**	**~ 1.0**
Estimated Production Potential, kb/d	**53****	**815**	**565**	**1,030**	**360**	**1,685**	**4,455**
Well EUR, kbls	200	550	280	125-250	300	500	
Well Costs, $million	4.5	5.5-8.5	4-6.5	3.5-5.5	3-5	5-7	
Notes: kb/d = 1000 b/d; Bbo = billion barrels of oil. Estimated recoverable oil = unproven technically recoverable oil. * value established by decline analysis; ** field value. Recovery factor = recoverable oil/oil-in-place. Estimated production potential is calculated with Equation (3). With exception of Elm Coulee, Recovery Factors refer to reported data on recoverable oil and oil-in-place. Production start-up refers to year when new drilling technologies were applied, e.g. in Avalon and Monterey.							
Sources: EIA2012, USGS2010, IEA2011, ARI2012, AAPG, Producers, and several other sources cited in References.							

Decline Analysis

The Elm Coulee field is the only tight oil play with ample production history to allow a comprehensive field decline analysis. The field was discovered in eastern Montana in 2000 and produces from the Bakken. At its peak in 2006, Elm Coulee was producing 53,000 b/d from 350 wells or roughly 150 b/d per well. Today, output has dropped to 24,000 b/d, and cumulative production is 113 million barrels of 41 °API, light sweet crude. Logistic decline analysis indicates an EUR of 130 million barrels which corresponds to a 5.6% recovery factor.

A short review of some operational aspects of the field is appropriate since it is the best analog of the Bakken at this time. More than 600 wells have been drilled in the field with over 1,000 laterals, some up to 10,000 feet. The Bakken interval ranges in thickness from 10 to 45 feet with porosities of 3% to 9%, and permeabilities averaging 40 microdarcys. It is slightly overpressured with a gradient of 0.52 psi/ft. Initial oil rates from the multi lateral wells range from 200 to 1,900 b/d, compared with less than 100 b/d for vertical wells. **Fig. 2** gives a matchstick look at the decline rate trend for Elm Coulee. Observe the steepness of its decline rate trend, similar to that of the shale gas plays and very dissimilar to that of conventional oil fields represented here by the giant Prudhoe Bay.

Table 4 gives initial well rates and first-year decline rates for Elm Coulee and the six major shale plays. With the exception of the Bakken which had its start in 2000, the other plays had starts after 2008. As such, the information on initial well rates and early well decline rates is limited because: 1) the number of wells drilled and producing is fewer and fragmented among many operators, and 2) information is slow in becoming public due to the intense economic activity associated with these oil plays. We therefore opted to give the best range of data for the different parameters, in contrast to the average values given for the shale gas plays. Data for shale plays is very location sensitive; many well samples are required to establish statistically reliable values.

Table 4 Initial Well Rates and First-Year Well Decline Rates
Tight Oil Plays

	Initial Well Rates, b/d	**Early Well Decline Rates, %**
Elm Coulee (Bakken)	425*	65
Bakken	2,000	65 - 80
Eagle Ford	1,340 – 2,000	70 - 80
Niobrara	400 - 700	80 - 90
Monterey	623	80
Avalon & Bone Spring	534	60

Sources: EPRINC2012, Producers, seekingalpha, and several others. * IP rates are for multi lateral wells; decline rates for vertical wells are more than 80%.

In general, first-year well decline rates are typically high for tight oil plays, varying from 65% to 90%, while initial well rates vary from 400 bopd to 2,000 bopd for the Bakken and Eagle Ford. For a type well in the Bakken, almost half (46%) of its EUR is produced by Year 5; the other half to be produced over the following 25 years! The Niobrara and Monterey are still under appraisal in specific areas as evidenced by their high well density: 8 and 12 wells per square mile, respectively, versus 2 for the Bakken, **Table 3**. For the sake of comparison, initial well decline rates for conventional oil field wells are in the range of 5-10% per year.

Regarding recovery efficiencies there are only two values available from field data. One, 5.6 % that was established by decline analysis for Elm Coulee and 1.25% for the Bakken as a whole.

This latter value is the result of an NDGS report released by the state of North Dakota in 2006; it is the value also used by the USGS in their assessments of other tight oil plays. Why this broad range of values?

As mentioned previously, shale gas and tight oil plays are continuous accumulations over extensive areas in contrast to conventional discrete oilfields that are geologically disconnected. In this respect, oilfields like the Elm Coulee are better described as sweet spots that have better-quality matrix reservoir properties (permeabilities greater than 0.15 millidarcys and extra natural fractures) than the surrounding area within the play. The recovery factor of 5.6% explicitly refers to the in-place volume of oil in the specific Elm Coulee sweet spot. When recovery is measured with reference to the entire active area surrounding the sweet spot, which includes productive and non-productive areas, then the recovery factor drops considerably.

Sweet spots are randomly located within a play. A play may have good hydrocarbon potential but widespread success in locating sweet spots is the final determinant. The recovery factor cited in the NDGS report refers to the average over the active area. It is the appropriate approach for continuous resource-based deposits, and a recovery factor of 1-2% seems to be the best estimate to be used for other emerging tight oil plays at this time.

Production Potential

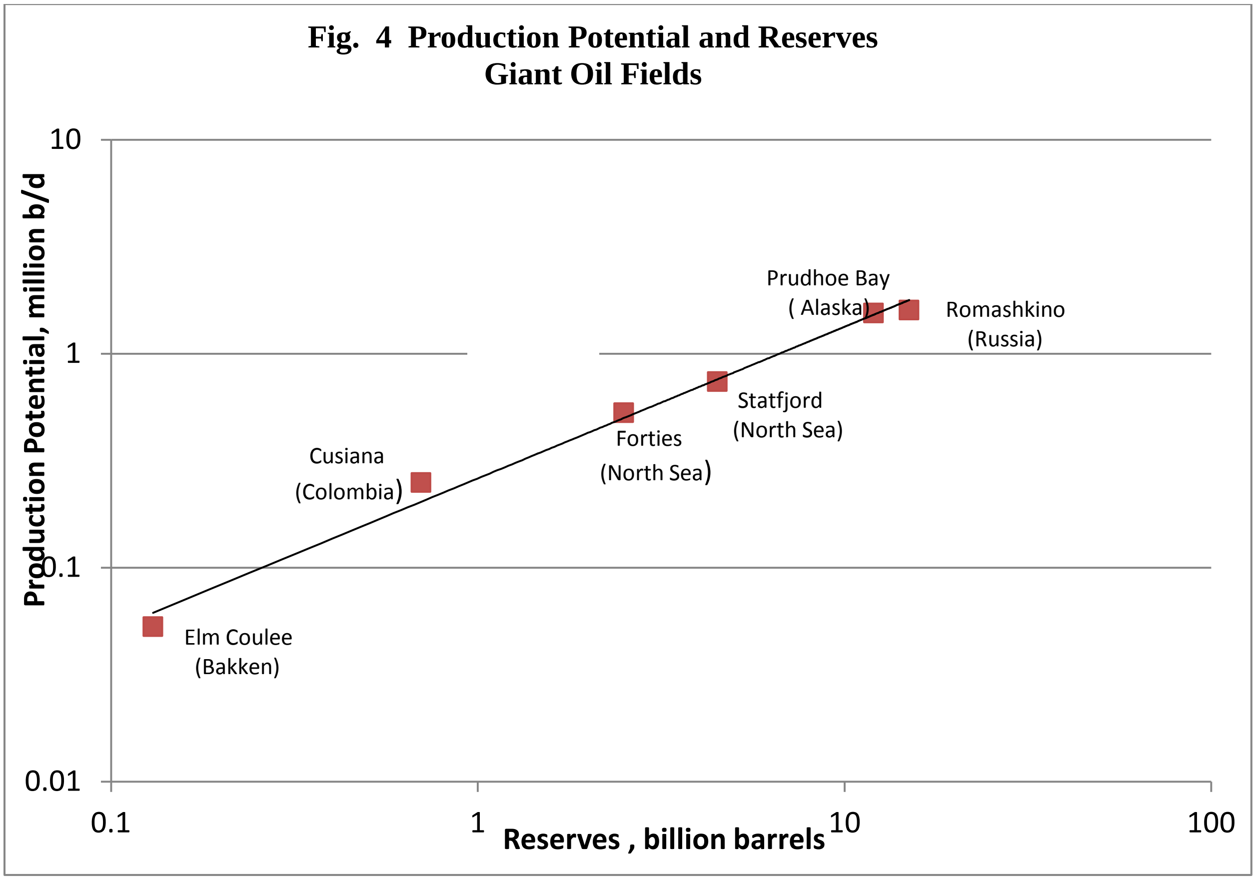
Fig. 4 shows the correlation between production potential and recoverable oil (EUR) for five conventional giant oil fields from around the world. When the values for the Elm Coulee field are included they fall perfectly on the trend. The resultant algorithm is:

$$q_{peak} = 0.26\ K^{0.7088} \qquad (3)$$

where q_{peak} is the production potential of the play with units of million b/d, and K is the size (reserves) of the play in billions of barrels (Bbo). The correlation coefficient (r^2) for Equation 3 is 0.993.

This relationship is pleasantly interesting since it confirms that tight oil reservoirs do follow the dynamics of the Darcy flow regime as do conventional oil reservoirs, an important contrast with shale gas reservoirs discussed previously. As a side remark, tight gas sands do behave in a way physically similar to conventional gas reservoirs; however, their recovery factors can be as low as 10%, with an average around 40%.

The above algorithm was used to estimate the production potential of the major plays in **Table 3,** based on the current estimates of recoverable oil. Potential estimates for the Bakken are 815,000 b/d, Eagle Ford 565,000 b/d, and Avalon/Bone Spring 360,000 b/d. Niobrara's estimated potential is 1.03 million b/d, and Monterey's is 1.68 million b/d. These huge potentials are strong incentives to resolve the equally huge technical challenges that lie ahead in these two plays.



Summary Results

An in-depth analysis was made of the production performance of the Barnett and Fayetteville shale gas plays, and of the Elm Coulee Bakken oil field. These are the only existing mature fields of shale gas and tight oil resource plays, and the object was to establish field performance values of key parameters such as recoverable oil and gas and recovery efficiencies and, ultimately to develop algorithms that can provide a reliable estimate of production potential. This latter parameter is fundamental to the planning of production and take-away infrastructure, and finally determines the value of the asset.

Salient results of the study follow:

a) The top three producing shale gas plays: Haynesville, Barnett, and Fayetteville account for 70% of total US shale gas output, currently about 20 bcfd.

b) Shale gas plays show unusually high field decline rates with very steep trends, a combination conducive to low recovery efficiencies. The average recovery efficiency is about 7%, in contrast to recovery efficiencies of 75-80% for conventional gas fields. This suggests that the estimate of recoverable gas for all US shale plays should be near 240 tcf, or half of the 482 tcf now reported.

c) A power law relationship was developed that provides an estimate of production potential from knowledge of the volume of recoverable gas. Estimates of production potential for three major shale gas plays are: Marcellus 26 bcfd, Haynesville 10 bcfd, and Woodford 2.7 bcfd. The Barnett and Fayetteville are currently near their peaks. Shale gas plays peak at rates 2.6 times those of conventional gas fields of the same size.

d) The top three producing tight oil plays: Bakken, Eagle Ford, and Niobrara account for 90% of total US tight oil output, currently about 620,000 b/d.

e) The Elm Coulee field is the only tight oil play with ample production history that allows a comprehensive field decline analysis. At this time, it is the best analog of the Bakken, the biggest producer of all tight oil plays; the Bakken accounts for almost two-thirds of total US tight oil output.

f) In some ways, tight oil and shale gas plays are similar. They are both extensive, exhibit high first-year well decline rates varying from 65% to 90%, and low recovery efficiencies averaged over the entire play: 7% for shale gas, and 1-2% for tight oil. For 'sweet-spots' within the play, such as the Elm Coulee field, oil recoveries can reach 5-6%.

g) The power law relationship for estimating oil production potential is the same for both tight oil and conventional oil fields! The algorithm developed gives estimates of production potential for the Bakken of 815,000 b/d, Eagle Ford 565,000 b/d, and Avalon/Bone Spring 360,000 b/d. Estimates of potential for the Niobrara and Monterey tight oil plays are 1.03 million b/d and 1.68 million b/d, respectively. These two emerging plays have huge production potentials which certainly are strong incentives to resolve the equally huge technical challenges associated with their development.

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Oct. 31, 2012

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