Unconventional Gas – Scale, Cost and Uncertainty

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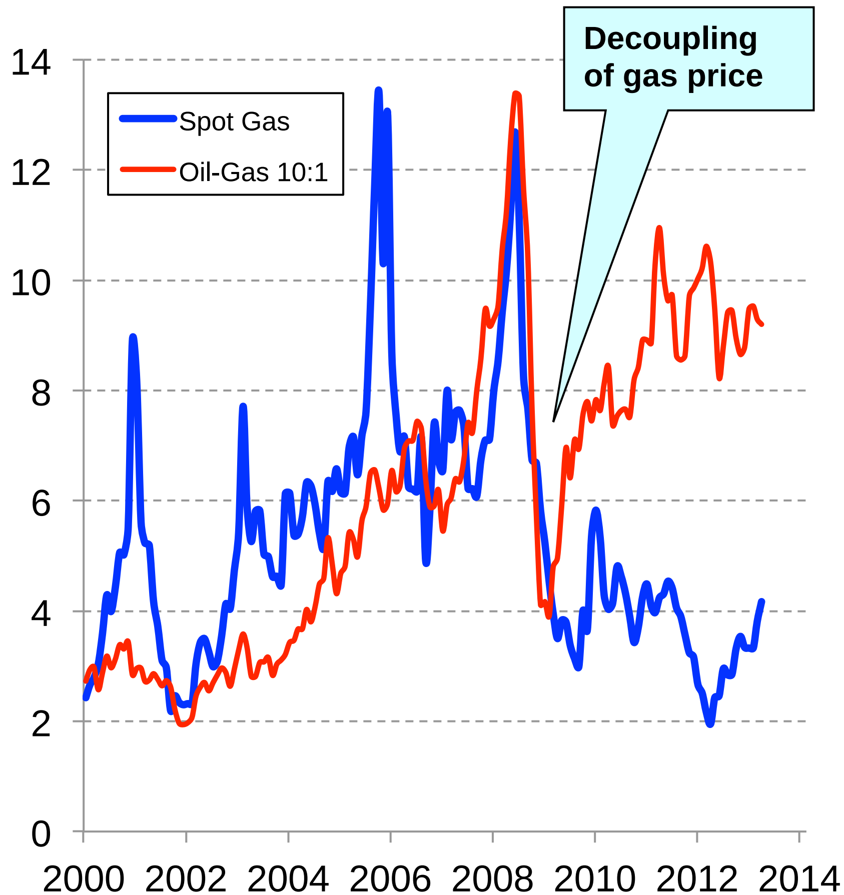
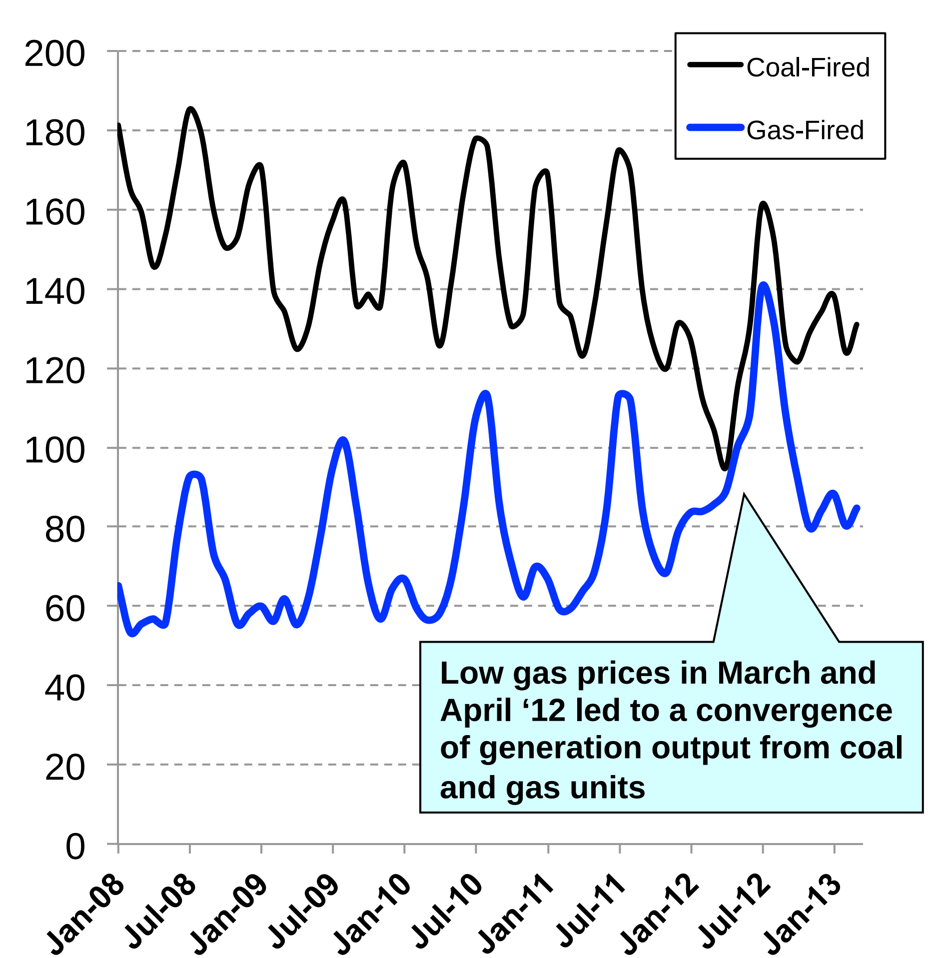
The past decade has been a period of huge change for natural gas in the United States – Perspectives on supply and price have been fundamentally altered and a much more gas-centric future is being envisaged by many

Comparison of spot natural gas price with historical oil-to-gas ratios
$/MMBtu of gas



Comparison of coal and gas-fired power generation levels in the U.S. since January 2008
TWhrs



Source: F. O’Sullivan, United States Energy Information Administration

The shale gas resource – Scale and uncertainty

Estimates of U.S. gas resources have grown dramatically since 2005 due to the emergence of shale as a recoverable resource – The resource's ability to support rapid production growth has also been notable

Illustration of growth in US natural gas proved reserve and resource estimates from '90 to '10
Tcf of gas

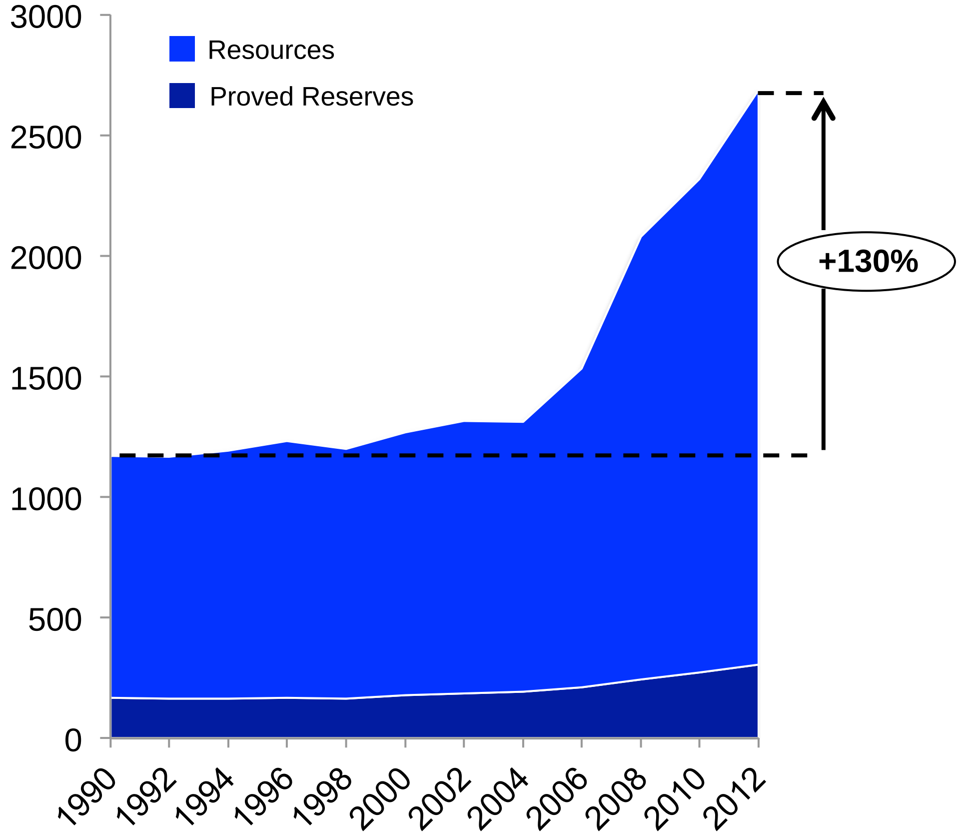
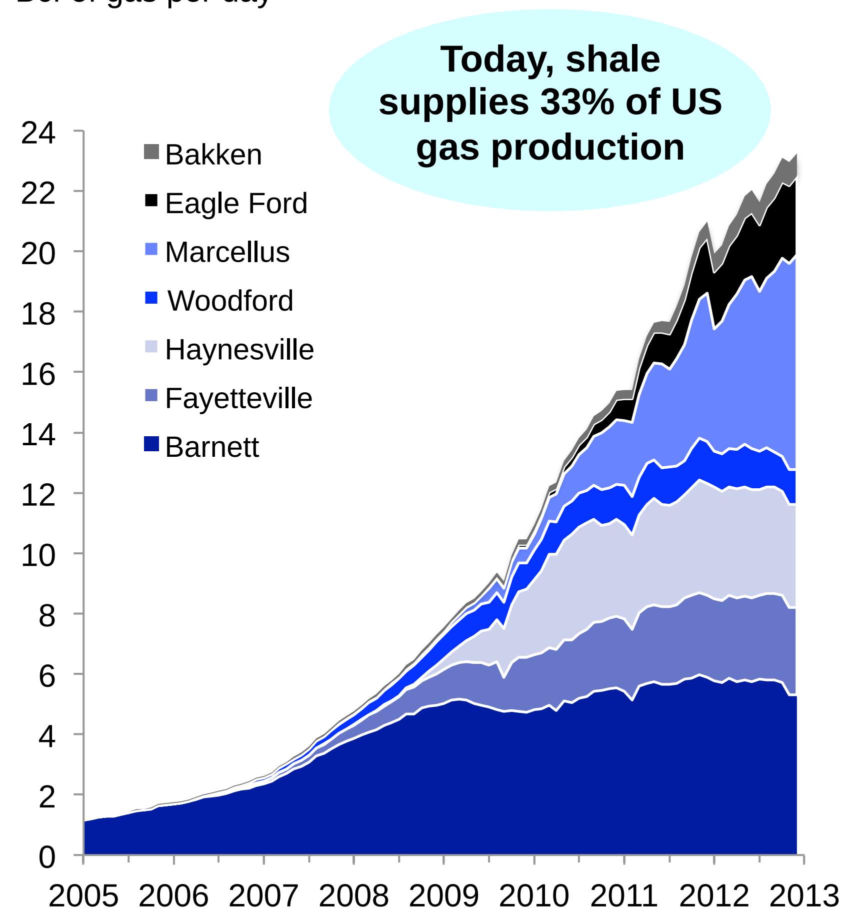


Illustration of production growth in the main U.S. shale plays since 2005
Bcf of gas per day

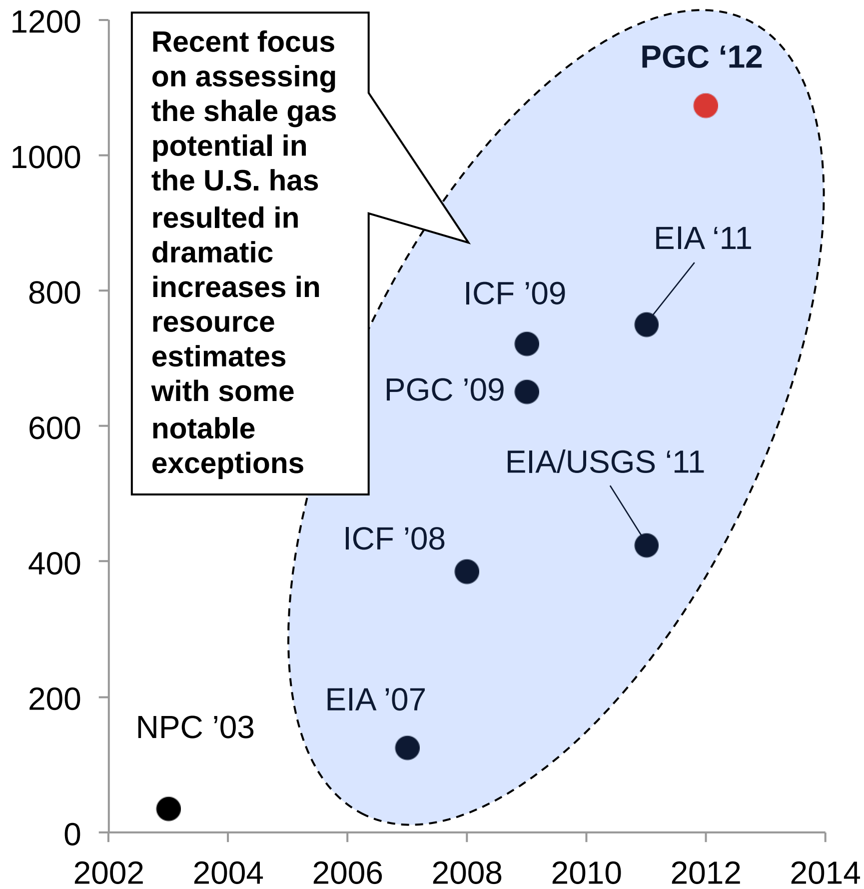


1. EIA 2010 assessment based on 2008 PGC assessment with updated estimates of technically recoverable shale gas volumes

Source: F. O'Sullivan, NPC data, PGC data, EIA data

However, shale gas production is still in its infancy and large uncertainty surrounds estimates of recoverable resources – The physics that govern production from shale are still not well understood

Comparison of mean estimates of shale gas resources in the United States
Tcf of Gas



Breakdown of the PGC 2012 shale gas resource estimates by major U.S. shale play*
Tcf of Gas

	Min	Most Likely	Max
Fort Worth Basin: Barnett Shale	11	48	83
Arkoma Basin: Fayetteville & Woodford	75	104	137
E. TX & LA Basin: Haynesville & Bossier	76	149	293
TX Gulf Coast Basin: Eagle Ford & Pearsall	29	59	105
Appalachian Basin: Marcellus, Ohio & Utica	220	563	1242
Uinta Basin: Mancos & Manning Canyon	37	60	129
Other Basins:	34	90	234
Total Mean Estimate:	482**	**1073**	2223**

* "Most likely" estimates can be aggregated by arithmetic addition to yield an aggregated estimate of shale gas resources in the United States. The per basin min and max numbers reported here assume perfect statistical correlation within basins

** US min and max totals are for illustrative purposes only, and are calculated by direct addition of volumes, not statistical aggregation

Source: F. O'Sullivan, Various commercial and institutional resource assessments

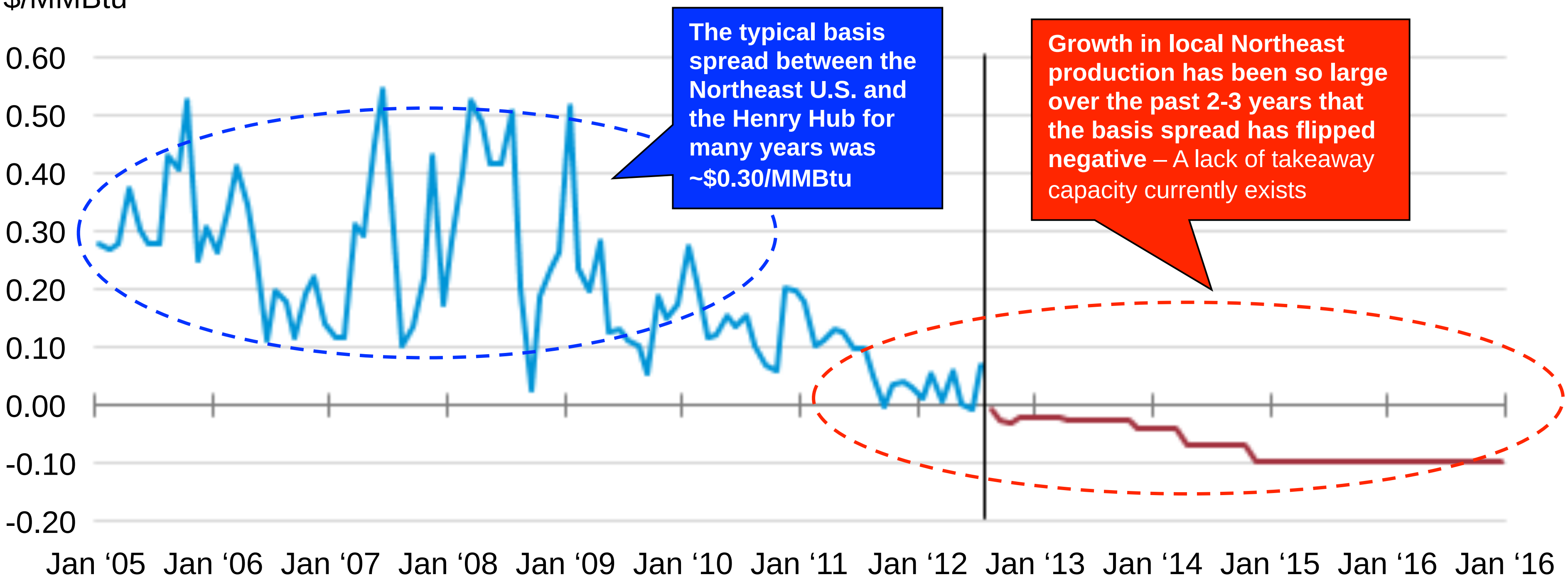
The emergence of unconventional gas has led to a major change in the geographical balance of U.S. production – The biggest play, the Marcellus, is located within the largest consuming region, the Northeast

Map of major North American shale plays – Active and prospective

Source: United States Energy Information Administration, Advanced Resources International

The elimination of the Northeast-Henry Hub "basis spread" is one major example of how the geographical balance of supply and demand has changed – Northeast midstream infrastructure has not been able to keep up with local production growth

Spread between Columbia TCO Appalachia (Marcellus Shale) and Henry Hub gas price
$/MMBtu

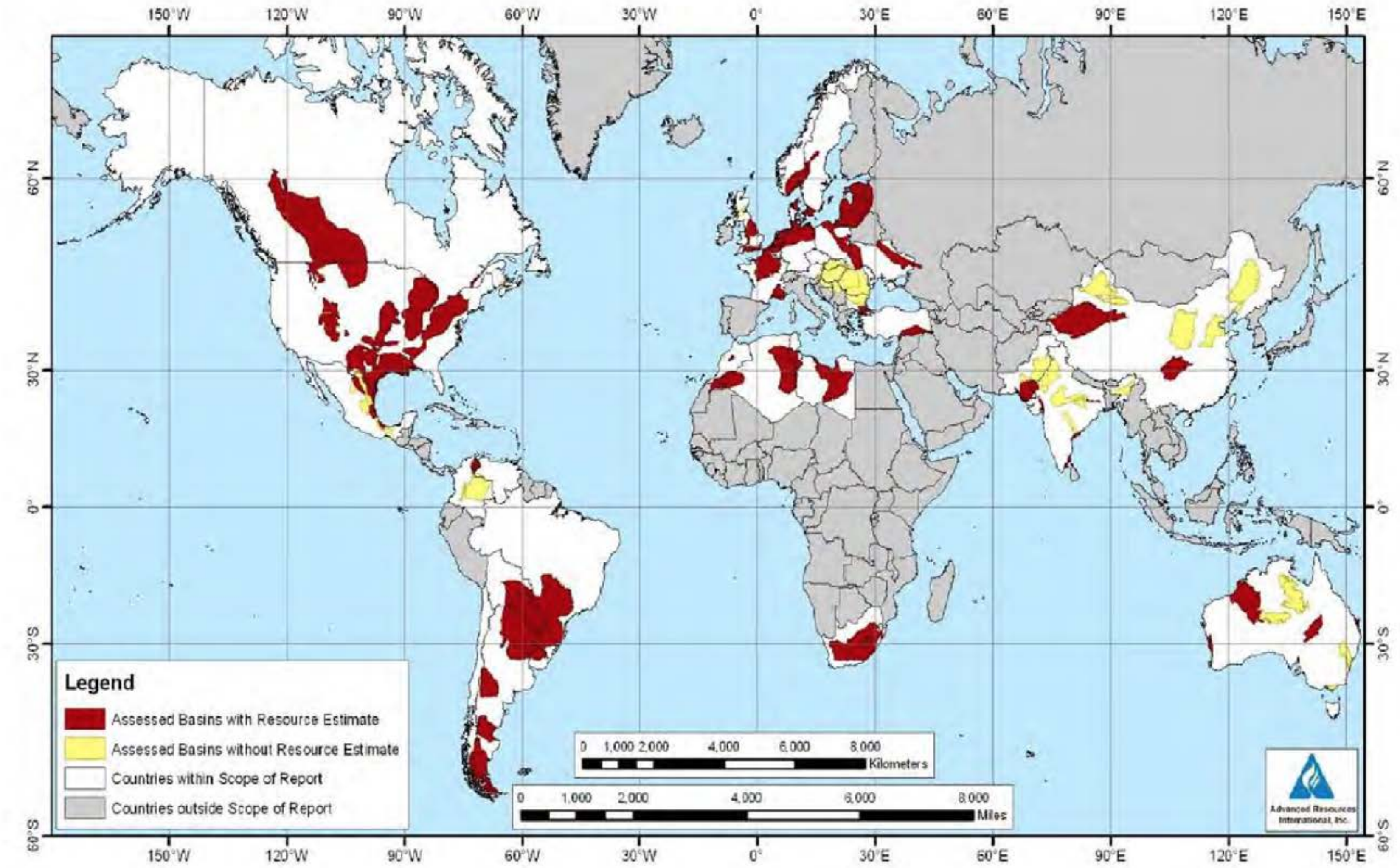


Today, the Marcellus Shale produces ~11% of total daily U.S. gas output – At the start of '10, it supplied <1%

Source: United States Energy Information Administration

Of course shale gas is not only a North American resources – There are numerous major shale basins across the globe

Map of selected global shale basins

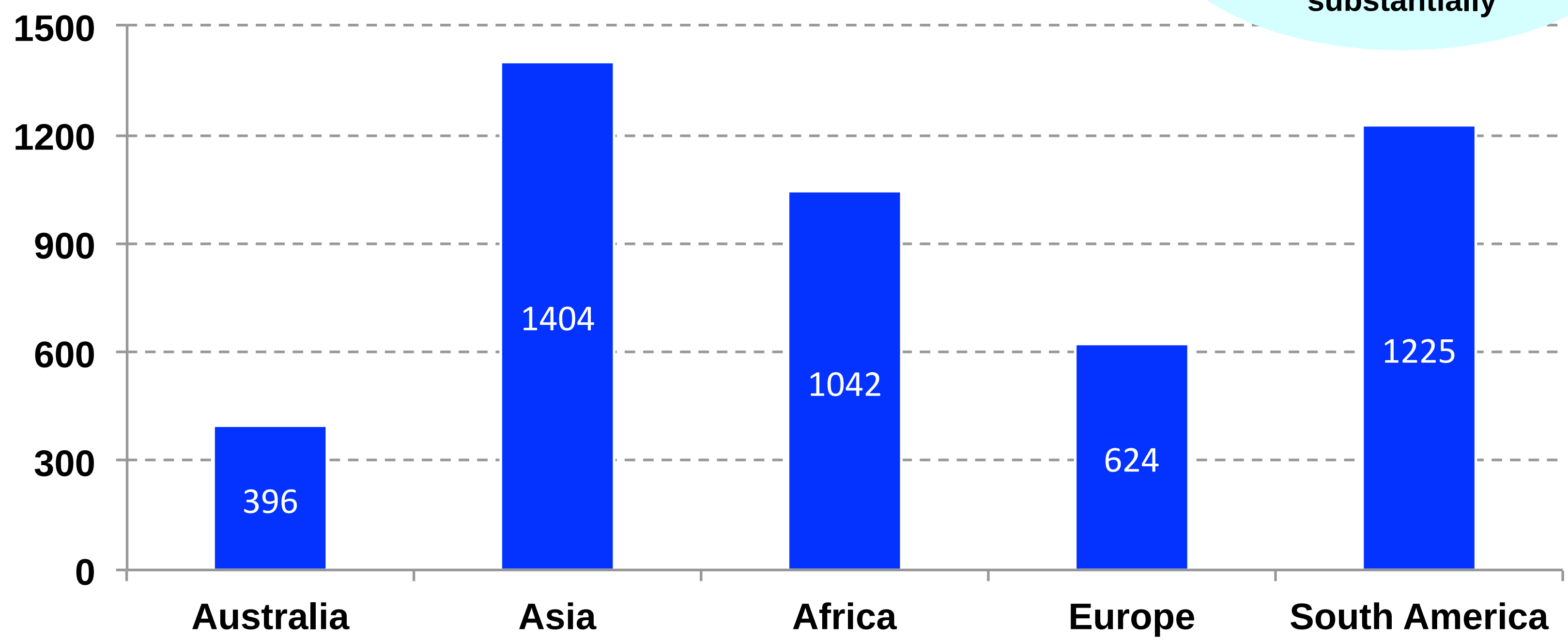


Source: EIA, Advanced Resources International

Early estimates suggest the scale of the global shale gas resource could be enormous – A recent assessment estimated that the global recoverable shale gas resource could be at least 6,000 Tcf

Breakdown of global recoverable shale gas resources by region
Tcf of gas

Study only assessed 31 countries – Future work expected to increase the resource estimate substantially

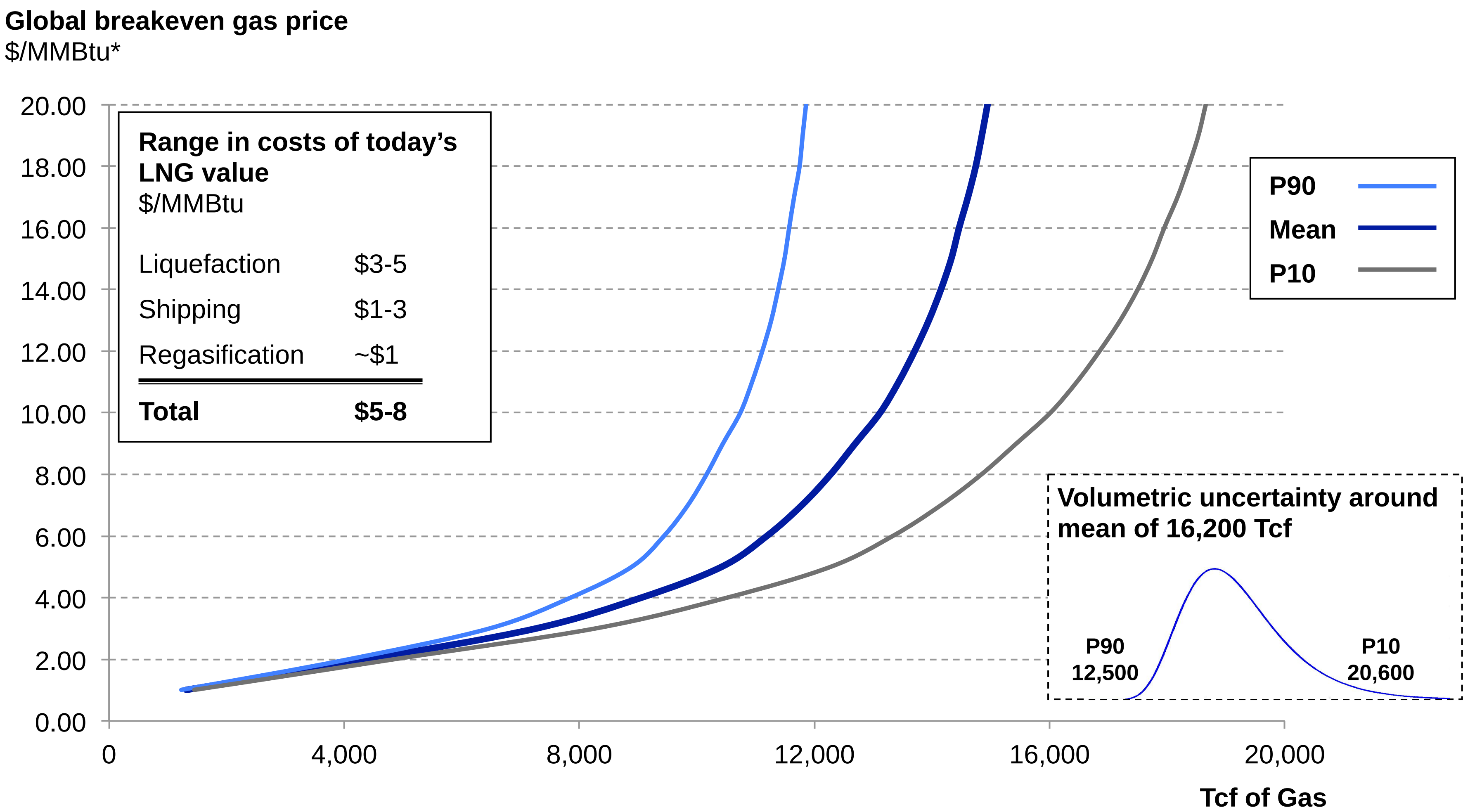


Top two shale gas resource holders by region	Asia	Africa	Europe	South America
	China : 1,275 Tcf	South Africa: 485 Tcf	Poland: 187 Tcf	Brazil: 226 Tcf
	India: 63 Tcf	Libya: 290 Tcf	France: 180 Tcf	Argentina: 774 Tcf

Source: World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, ARI 2011

Shale resource productivity and economics – What do these resources really cost?

Globally, large gas resource can be developed at very low cost, though delivery is not cheap – U.S. gas, even with the shale resource is structurally more expensive than much of the global resource

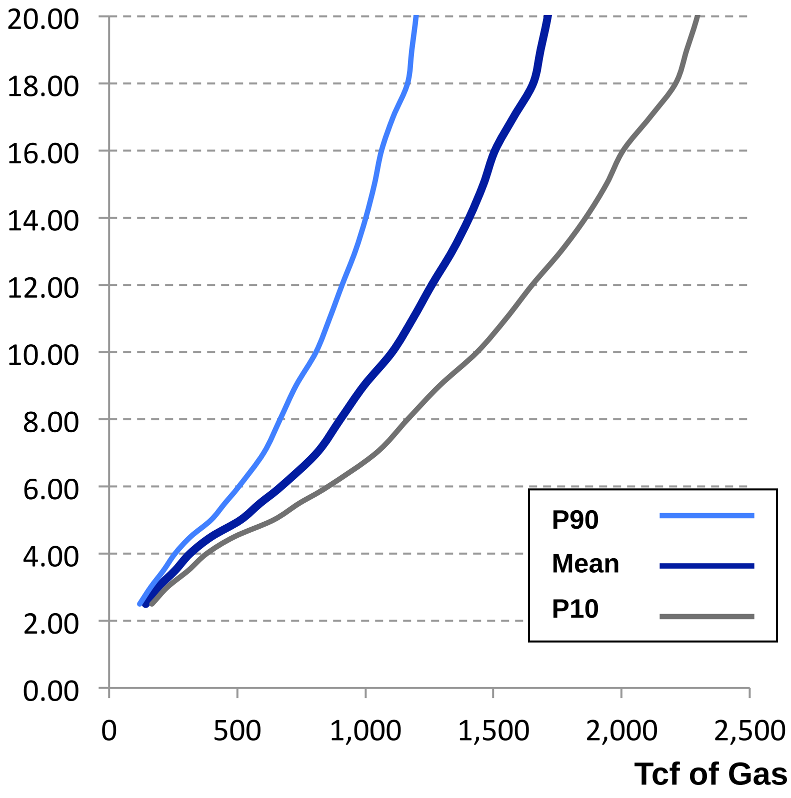


* Cost curves based on 2007 cost bases. North America cost represent wellhead breakeven costs. All curves for regions outside North America represent breakeven costs at export point. Cost curves calculated using 10% real discount rate

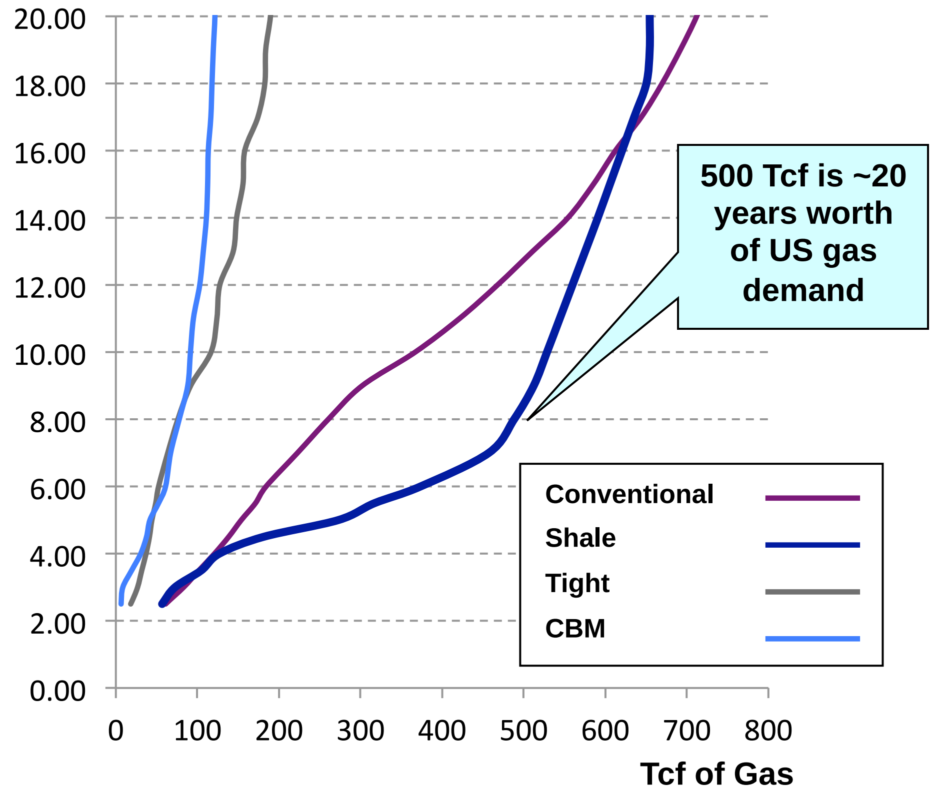
Source: F. O'Sullivan, MIT Gas Supply Team analysis, ICF Hydrocarbon Supply Model

The US has an abundance of moderate cost gas resources, with more than 30 years worth available at or below $6.00/MMBtu – Remarkably, shale gas makes up the majority of the lower-cost resource

Aggregate United States natural gas supply curve
$/MMBtu breakeven gas price*



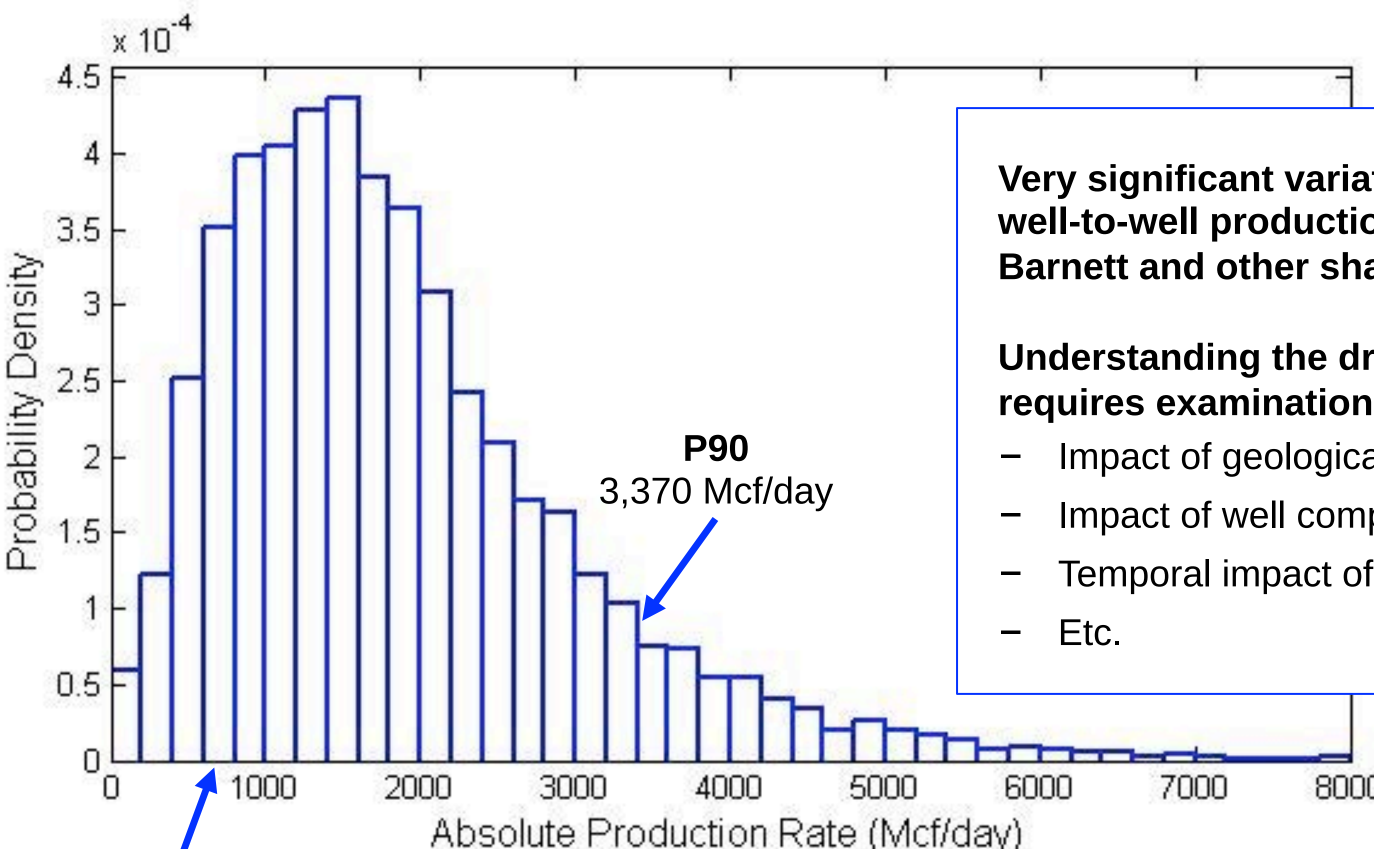
Breakdown of United States natural gas supply curves by resource type
$/MMBtu breakeven gas price*



* Cost curves calculated using 2007 cost bases. U.S. costs represent wellhead breakeven costs. Cost curves calculated assuming 10% real discount rate
Source: MIT Gas Supply Team analysis, ICF Hydrocarbon Supply Model, Data strictly for illustrative purposes only

An assessment of well performance in the Barnett Shale reveals interesting features – There is appreciable spread is in well-to-well performance and consistency in the shape of the distribution for different metrics

Distribution of absolute peak month well productivity[1]
All horizontal shale wells drilled in Barnett Shale between 2005 and 2011



P90
3,370 Mcf/day

P10
635 Mcf/day

Very significant variation is evident in the well-to-well production performance of Barnett and other shale play wells

Understanding the drivers of this variability requires examination of many factors

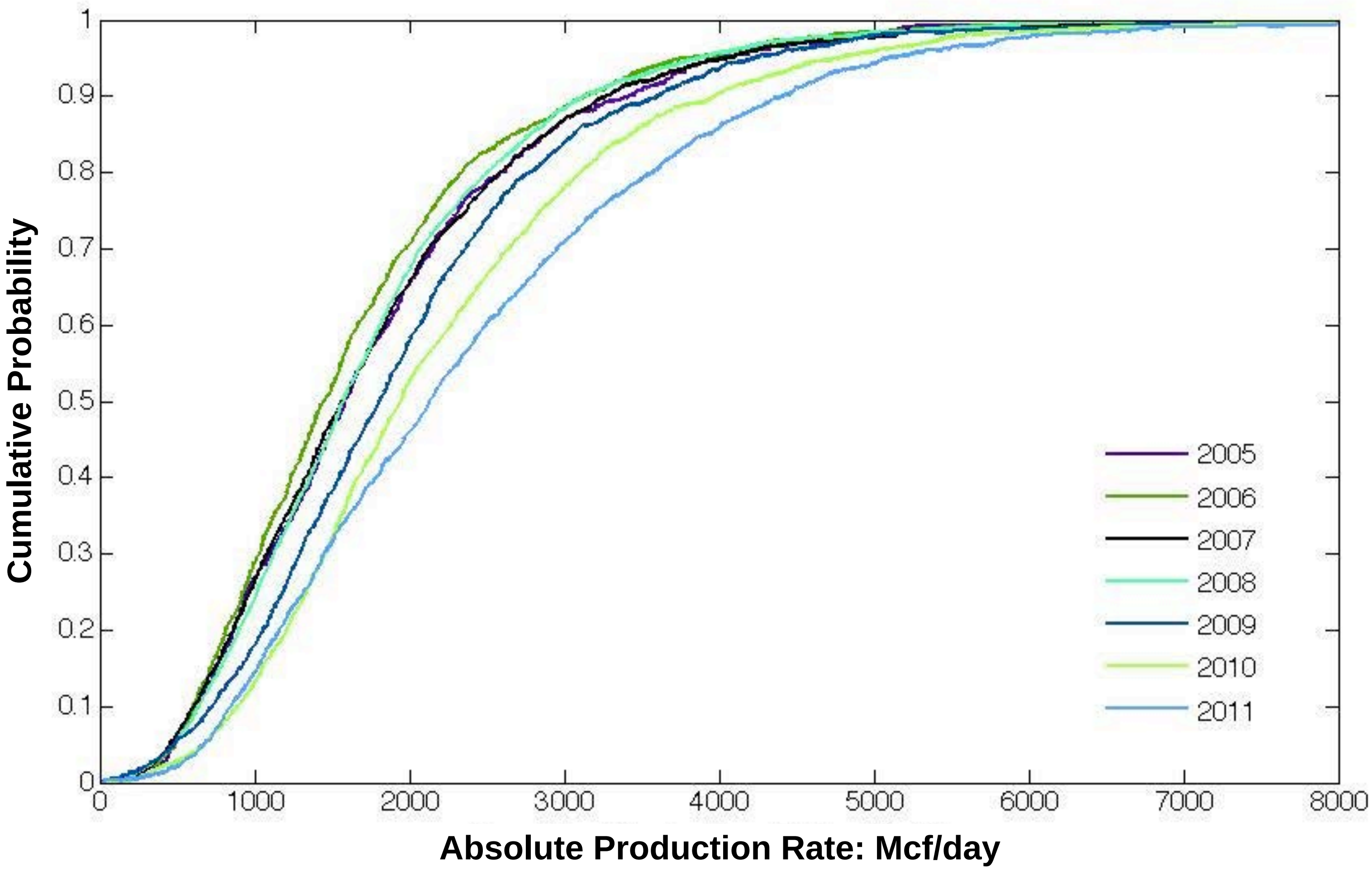
- Impact of geological variation
- Impact of well completion design
- Temporal impact of a creaming process
- Etc.

P90 – P10 Spread = 5.3X

1. Peak month production rate reported in units of Mcf/day
Source: F. O'Sullivan, HPDI production database

Since 2005, the mean absolute productivity of Barnett wells has increased; however, the scale of intra-vintage variation in well performance has remained consistent – This pattern can be observed across multiple performance metrics

Intra-vintage variation of Barnett Shale well absolute peak-month gas production
Horizontal wells only

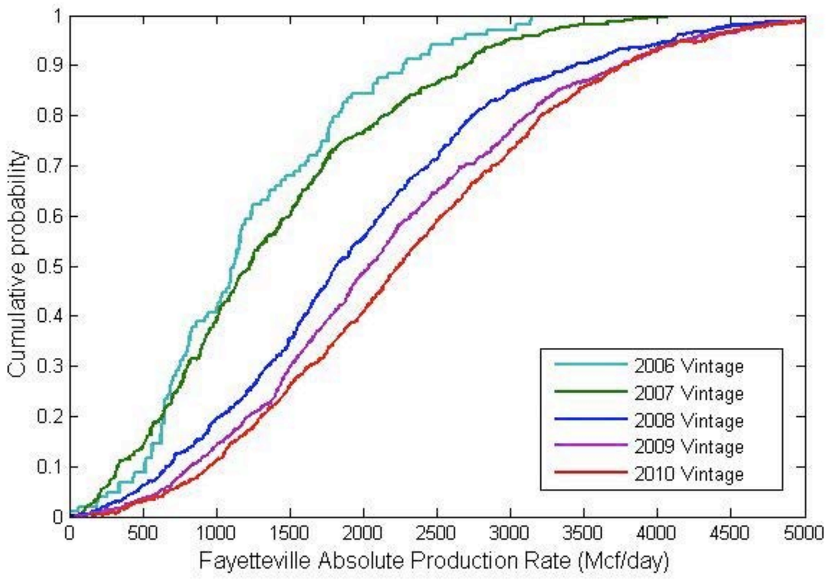


- **Absolute well productivity has been increasing since 2005**
- **The absolute productivity of a mean 2011 well was 33% higher than that of a '05 well**
- **The P90-P10 performance spread is ~5X for each vintage**

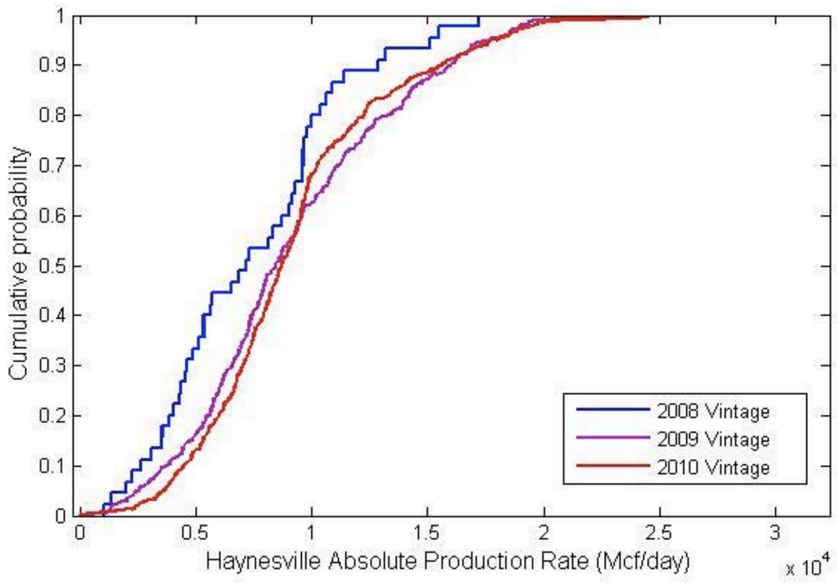
Source: F. O'Sullivan, HPDI production database

The trends observed in the Barnett well performance data are also evident in the well data of other plays – In particular, the large spread in intra-vintage well performance seen in the Barnett data can also be observed in other major plays

Per-vintage cdf of Fayetteville Shale well absolute peak-month gas production
Horizontal wells only



Per-vintage cdf of Haynesville Shale well absolute peak-month gas production
Horizontal wells only



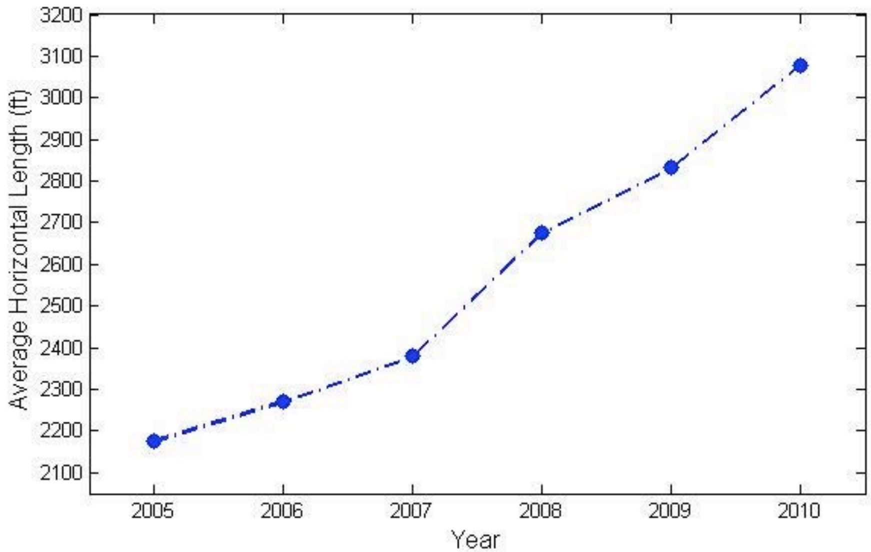
2010 vintage peak-month production rate data for Fayetteville, Haynesville and Marcellus Shale horizontal wells
Mcf/day

Play	# of wells	Mean	Median	P90	P10	P90-P10 Ratio
Fayetteville	870	2.320	2,240	3,750	960	3.9
Haynesville	478	9,300	8,690	15,560	4,510	3.5
Marcellus	468	3,280	2,780	6,130	1,180	5.2

Source: HPDI production database

The impact of increasing well lateral lengths on shale well performance is an important consideration and is captured by considered *specific* rather than *absolute* performance metrics – In the Barnett, the *specific* metrics have similar shaped distributions to those of the *absolute* metrics

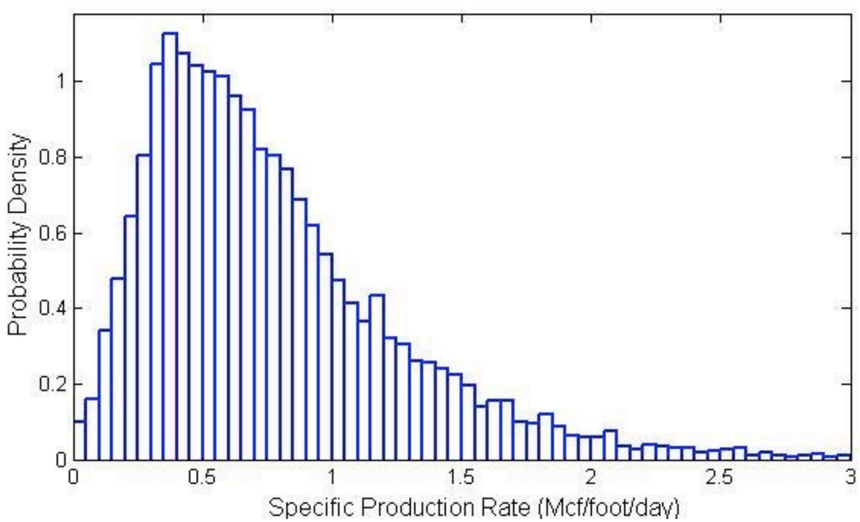
Year-to-year trend in average well lateral lengths in Barnett Shale



- ***Specific*** **rather than** ***absolute*** **metrics allows for a more apples-to-apples assessment of shale well productivity**
- **Between 2005 and 2010 the average lateral length of horizontal wells in the Barnett Shale increased by ~40% from 2,200' to 3,100'**

Distribution of specific peak month well productivity[1]

All horizontal shale wells drilled in Barnett Shale between '05 and '11

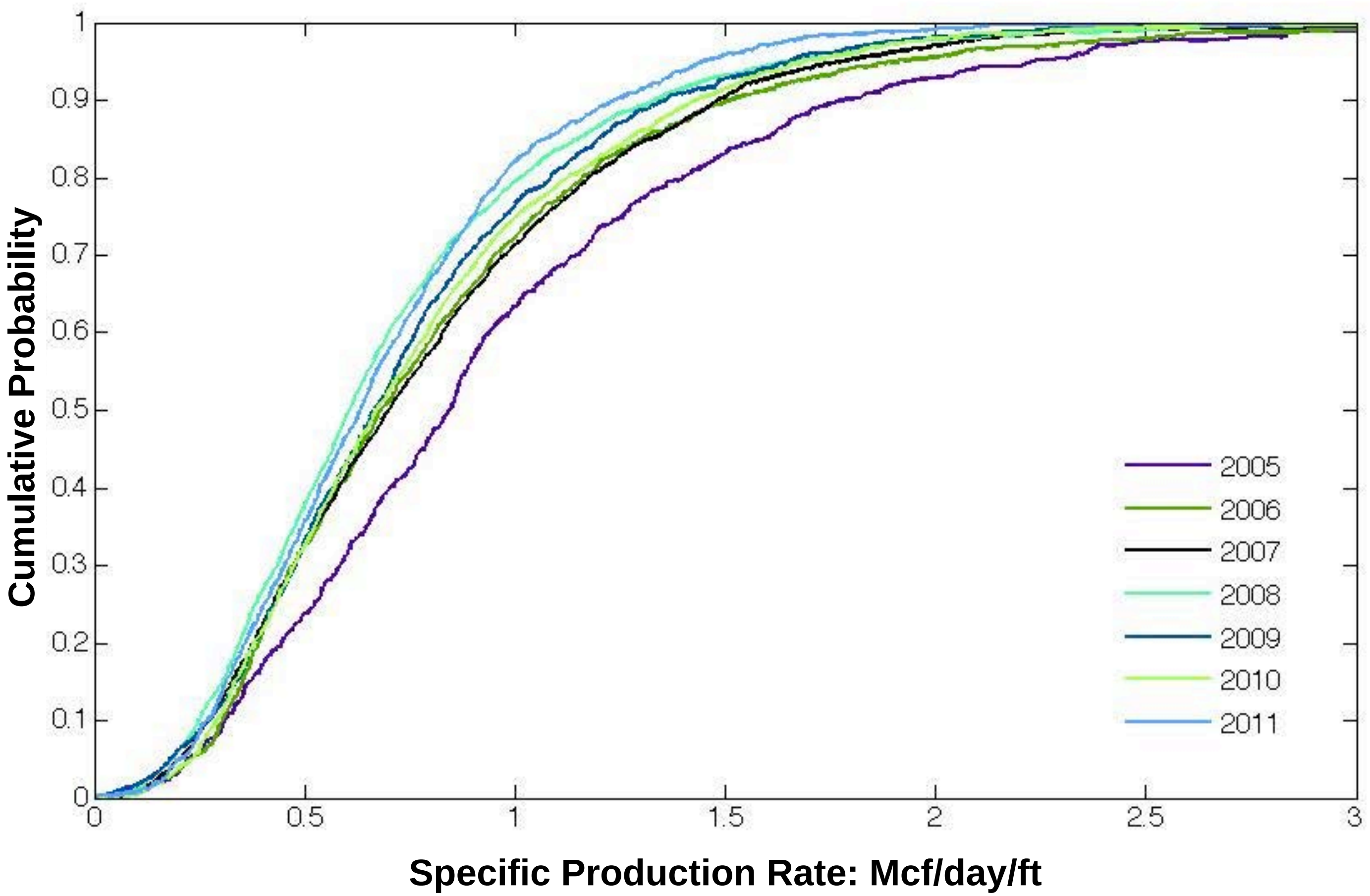


- ***Specific*** **productivity metrics for the Barnett have a very similar distribution to the** ***absolute*** **metrics**
- **The P90-P10 spread in** ***specific*** **productivity for the Barnett well ensemble is 5.4X**

Source: F. O'Sullivan & Q. Ejaz, "The North American Shale Resource – Characterization of Spatial and Temporal Variation in Productivity," IAMG 2013, Madrid Spain, HPDI production database

An analysis of *specific* well productivity data for the Barnett reveals that well productivity has actually fallen since 2005 – The average specific peak month well productivity in 2011 was 29% lower than it was in 2005

Intra-vintage variation of Barnett Shale well *specific* peak-month gas production
Horizontal wells only

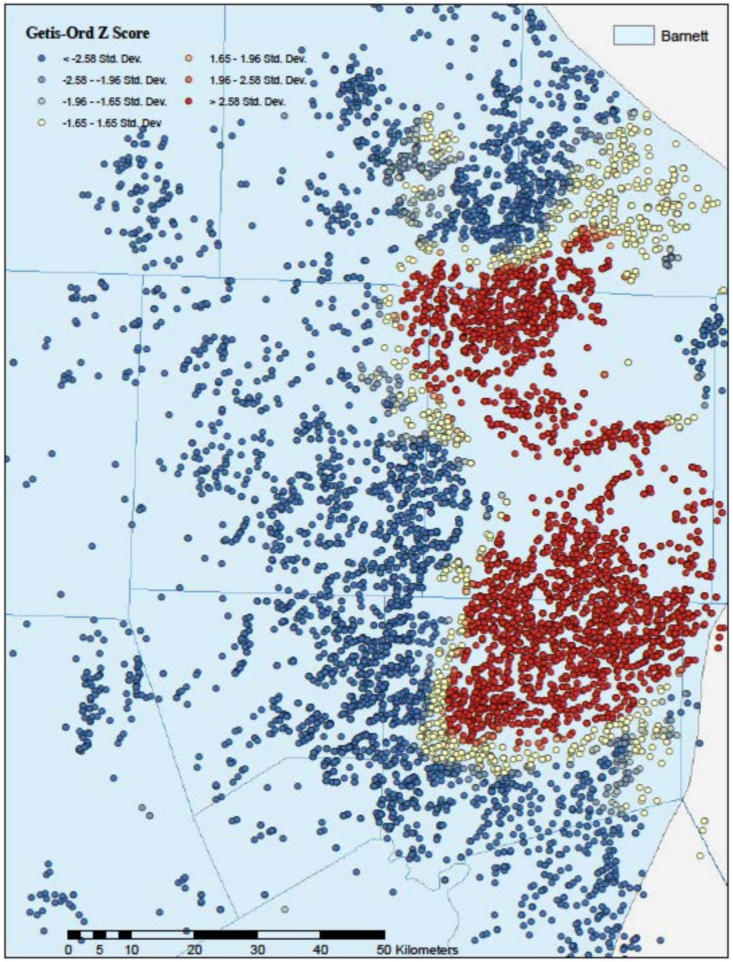


- The fall in *specific* well productivity means that on a per-foot-of-lateral basis, today's wells are not as productive as wells drilled in 2005
- The higher productivity of the 2005 well vintage may indicate some form of creaming process
- The year with the lowest *specific* productivity, 2008, also happened to be the year when the highest number of wells were drilled and so it is likely that lower quality acreage was being developed

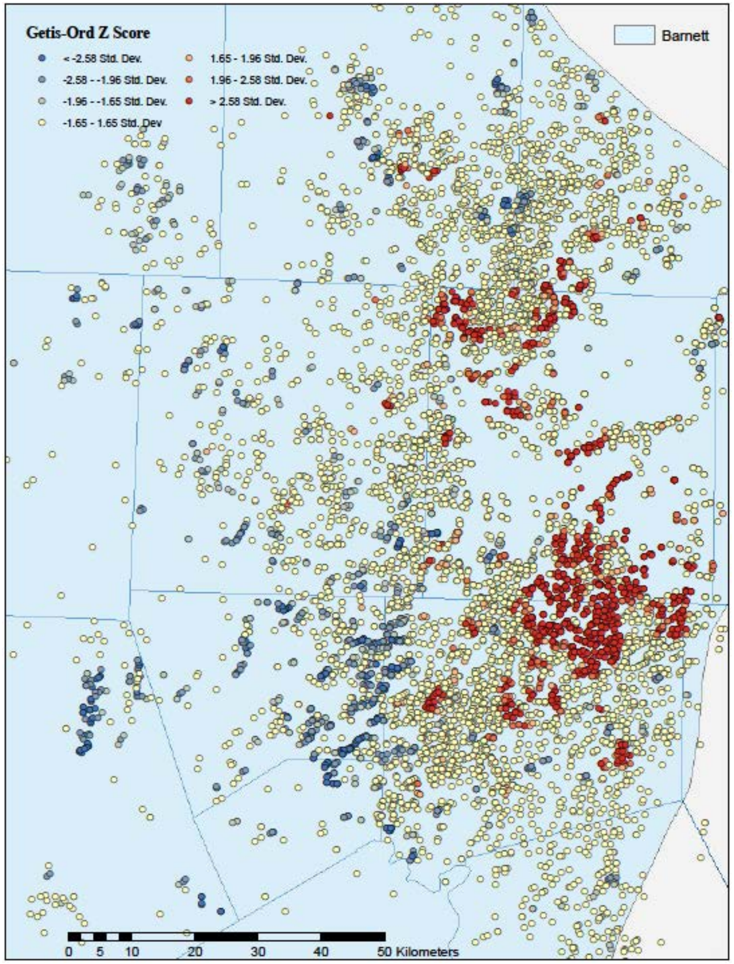
Source: F. O'Sullivan,, HPDI production database

Shale plays are generally characterized as having core and non-core acreage, but asset quality is in fact much more complex – In all plays, well performance is statistically random over operationally relevant length-scales

***Z*(*G*$_i$) scores of specific peak month Barnett well productivity calculated at 10km length scale**
All active H-wells drilled since 2005



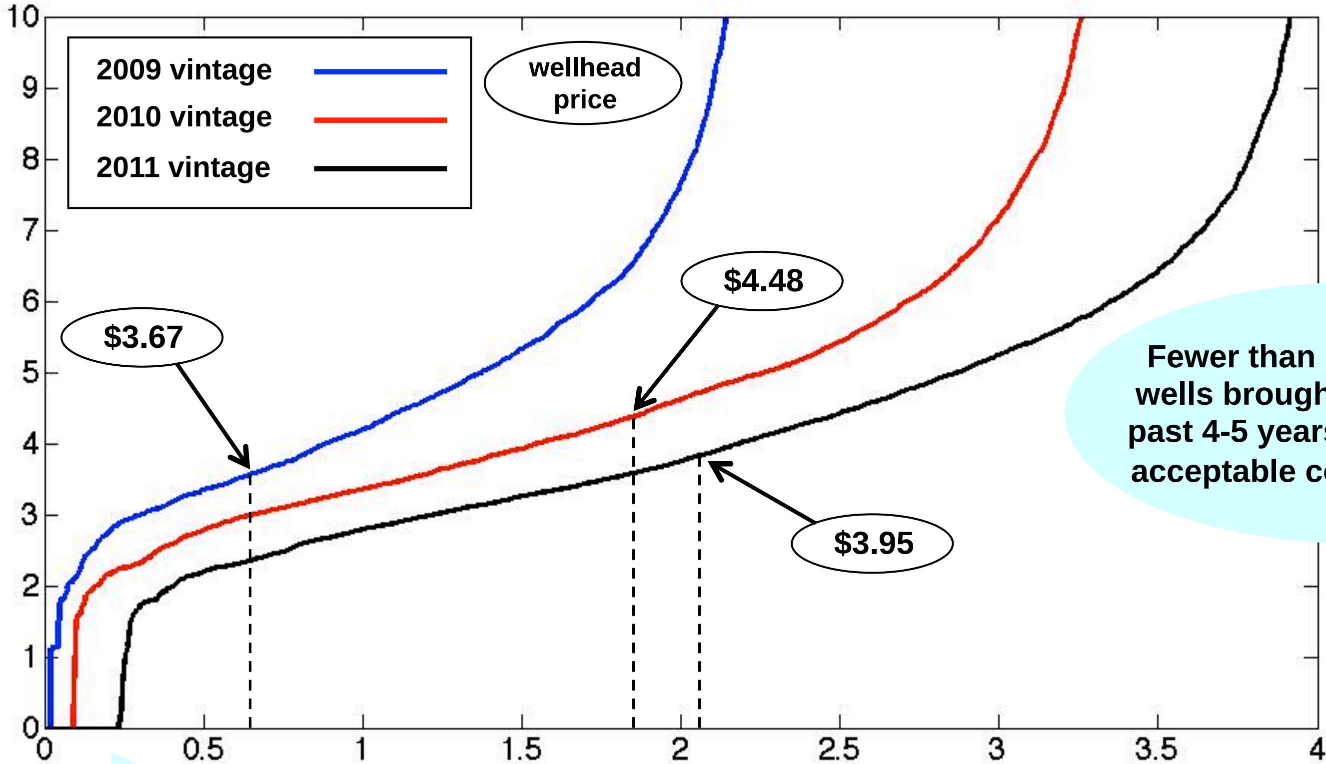
***Z*(*G*$_i$) scores of specific peak month Barnett well productivity calculated at 1km length scale**
All active H-wells drilled since 2005



Source: F. O'Sullivan & Q. Ejaz, "The North American Shale Resource – Characterization of Spatial and Temporal Variation in Productivity," to be presented at IAMG 2013, Madrid Spain

Intra and inter-play variability in shale productivity has major implications for the economics of the resource – Extensive drilling has pushed supply up and prices down, but much of this gas has been produced below cost

Retrospective U.S. shale gas curves for the '09, '10 and '11 well vintages
$/Mcf[1]



Fewer than half of the shale wells brought online over the past 4-5 years have yielded an acceptable commercial return

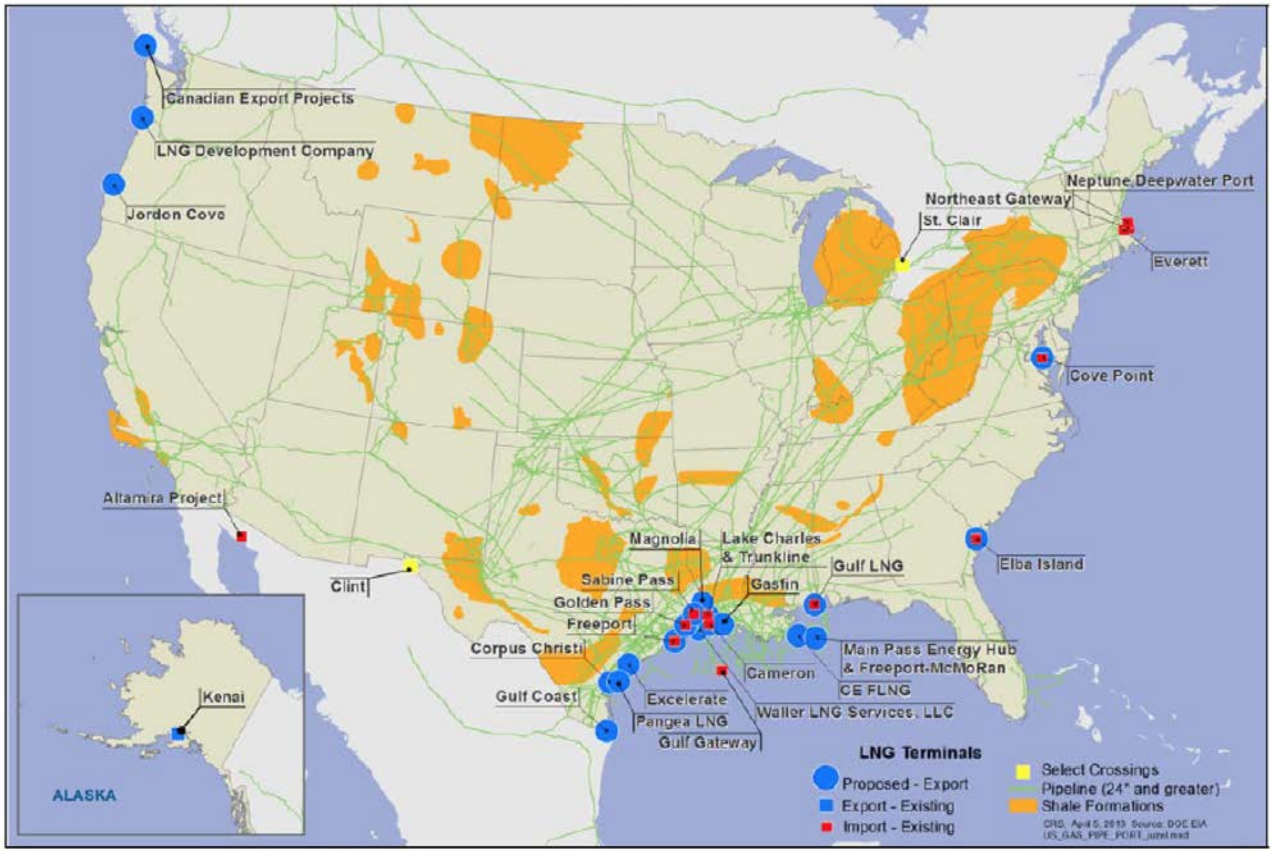
First 12 month gas production from shale well vintage
Tcf of Gas

Liquids targeted drilling is increasingly delivering ultra low-cost gas to the system

1. Supply curves include: Bakken, Barnett, Eagle Ford, Fayetteville, Haynesville, Marcellus and Woodford plays, and represent only gas produced by horizontal wells
Source: F. O'Sullivan

A controversial result of the U.S. gas renaissance is the potential for the export of gas via LNG – Perhaps the ultimate evidence of the impact of shale is that owners of LNG import terminals are trying to “turn around” their plant

Map of select U.S. gas import/export infrastructure

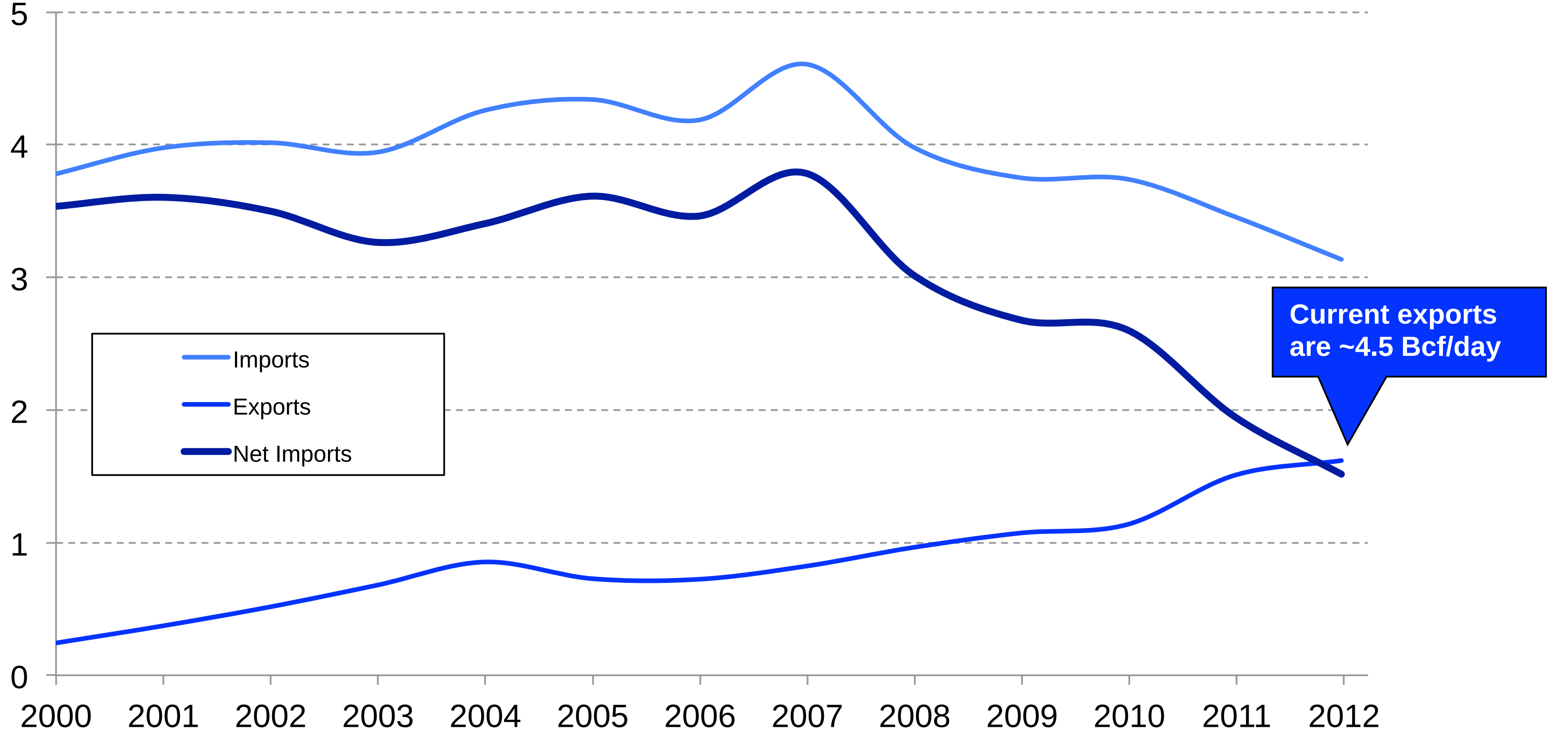


- The U.S. has the world’s second largest LNG import capacity (~17 Bcf/day)
- In 2011, the U.S. LNG import capacity factor was <5%
- Currently applications to export ~30 Bcf/day of LNG have been received by the U.S. DOE
- 25 Bcf/day of exports to FTA countries has been approved
- 3.6 Bcf/day of exports have been approved to non-FTA countries
  - 2.4 Bcf from Sabine Pass
  - 1.4 Bcf from Freeport
- 1.2 Bcf will come online in 2016 and a further 1.2 Bcf in 2018 at Sabine Pass

Source: United States Energy Information Administration, CRS

The potential for LNG exports from the US has led some domestic users to voice concern – The reality is that pipeline exports are already growing rapidly and the level of LNG exports is likely to be modest

Variation in U.S. natural gas imports and exports from 2000 and 2012
Tcf per year



Source: United States Energy Information Administration, CRS

The Natural Gas Revolution – Some synthesis

Over the past decade, the emergence of unconventional gas, and particularly shale gas has dramatically altered perceptions of long-term gas supply in North America – Estimates of the U.S. recoverable gas resource have more than doubled since 2005 to well over 2,500 Tcf

Along with its scale, the North American shale resource appears to have relatively attractive economics, with 350-400 Tcf of gas recoverable at $6.00/MMBtu or less – A key challenge being faced by operators today is learning how to deal with the large well-to-well performance variability evident among contemporary shale wells ensembles

The exceptionally low natural gas prices seen in North America over the past several years are not representative of the prices necessary to allow for the sustainable development of shale gas – Currently, the mean breakeven gas price for dry wells in all the major U.S. shale plays is at least $4.00. Co-production of liquids reduces this, but most plays are very dry.

The idea of LNG exports from the U.S. has become controversial; however exports are growing rapidly even without LNG and the additional demand this decade from LNG will likely be modest in overall terms – An important consideration for U.S. exports is what the “equilibrium” price of shale gas will be over the longer term

Initial assessments of the shale gas resources outside of North America suggests very large technically recoverable volumes, but there is also significant uncertainty – It remains unclear what it will cost to develop many of the internationals shales; however, they are likely to be appreciably more expensive than U.S. plays

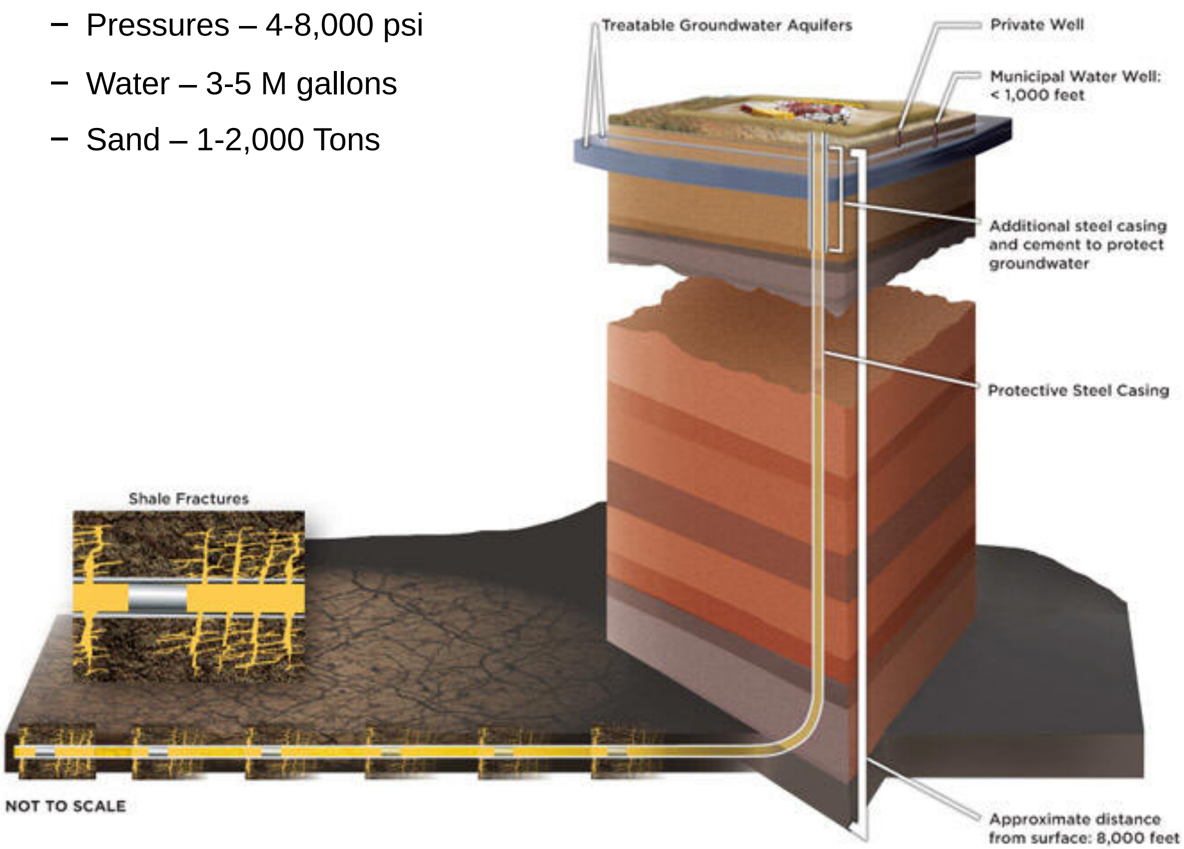
Very real environmental concerns exist regarding the water, air and community impacts that accompany unconventional gas and oil development – These issues are certainly challenging, however, on balance it appears they are also manageable given effective regulation

Unconventional natural gas production – The environmental issues

Hydraulic fracturing and horizontal drilling have been central enablers of the contemporary exploitation of unconventional resources – Fracturing is accompanied by a range of complex environmental issues

Contemporary hydraulic fracturing

- Hydraulic fracturing a single well demands:
  - Horse power – 20–30,000 HP
  - Pressures – 4-8,000 psi
  - Water – 3-5 M gallons
  - Sand – 1-2,000 Tons

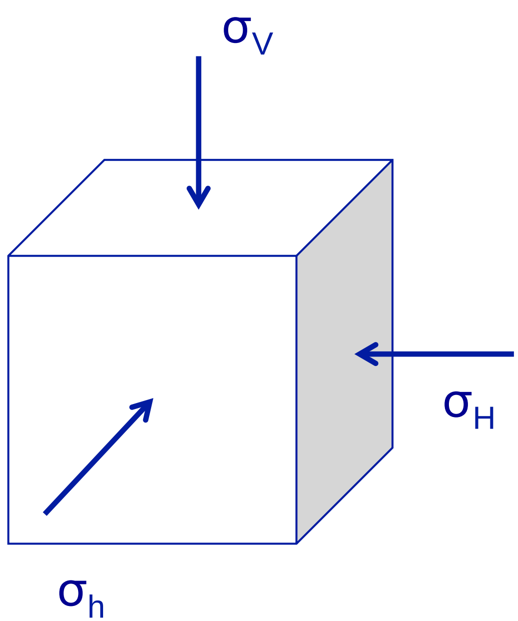


Some of the environmental issues associated with hydraulic fracturing

- **Water impacts**
  - Ground water and surface water contamination
  - Very large and impulsive demand on limited local resources
- **Air impacts**
  - Fugitive methane leakage
  - VOC emissions and other local air quality impacts
- **Community impacts**
  - Heavy traffic and surface disturbance
  - Ecosystem fragmentation

Rock strata in the lithosphere exist in a complex stress environment that has important implications on hydraulic fracturing – Induced fractures will generally form normal to the direction of the smallest principal *in situ* stress

Illustration of in situ principal stresses acting on a rock layer



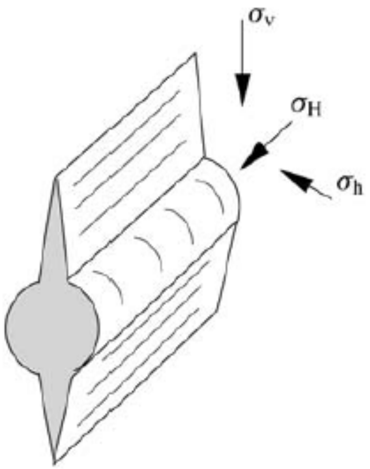
It is typical that the vertical stress be the largest which has implications for fracture orientation

$$\sigma_V > \sigma_H > \sigma_h$$

Fracturing from horizontal wells

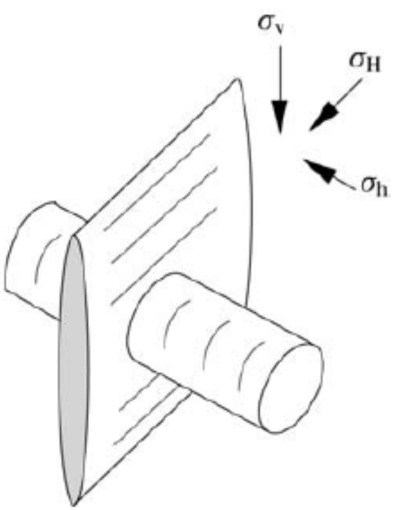
Case 1: Well bore azimuth parallel to maximum horizontal stress

Fracture will be parallel to well bore



Case 2: Well bore azimuth parallel to minimum horizontal stress

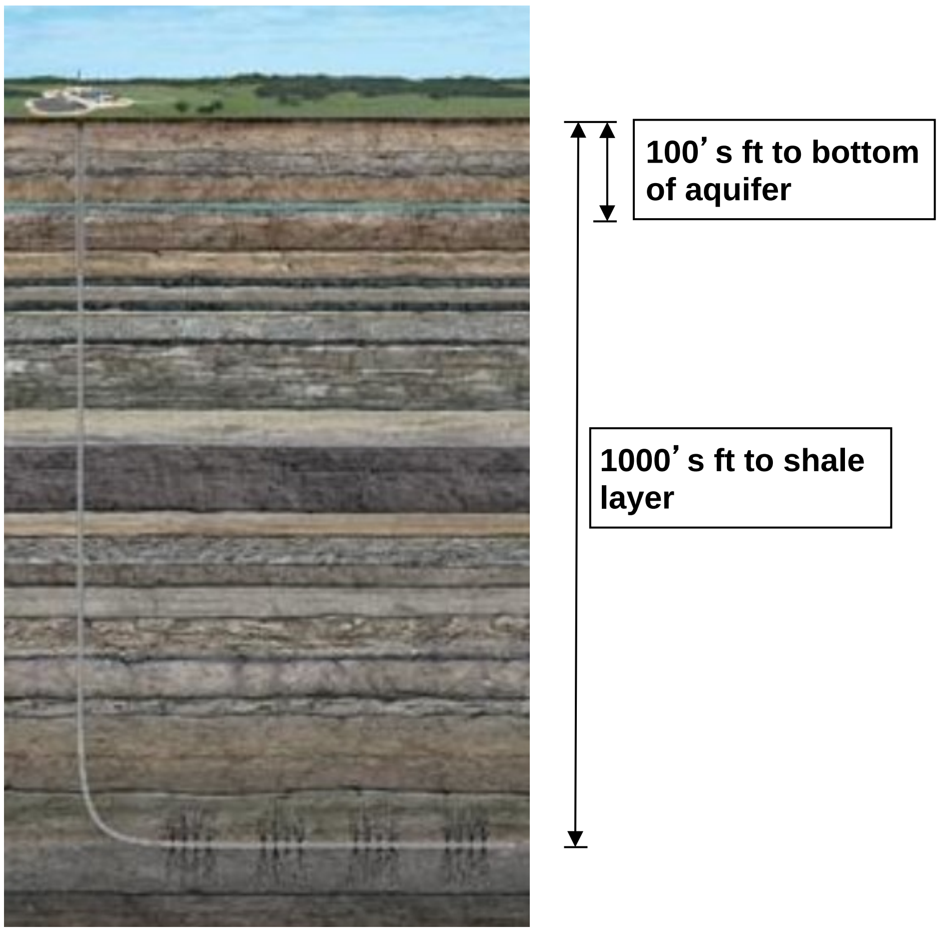
Fracture will be normal to well bore



Source: Petroleum Related Rock Mechanics, 2008

Concern exists about many water-related issues including contamination of freshwater aquifers with fracturing fluids – Analysis suggests this may be less of an issue than surface water management

Illustration of separation between freshwater aquifers and shale zone



Depths to freshwater aquifers and producing layers in major shale plays[1]

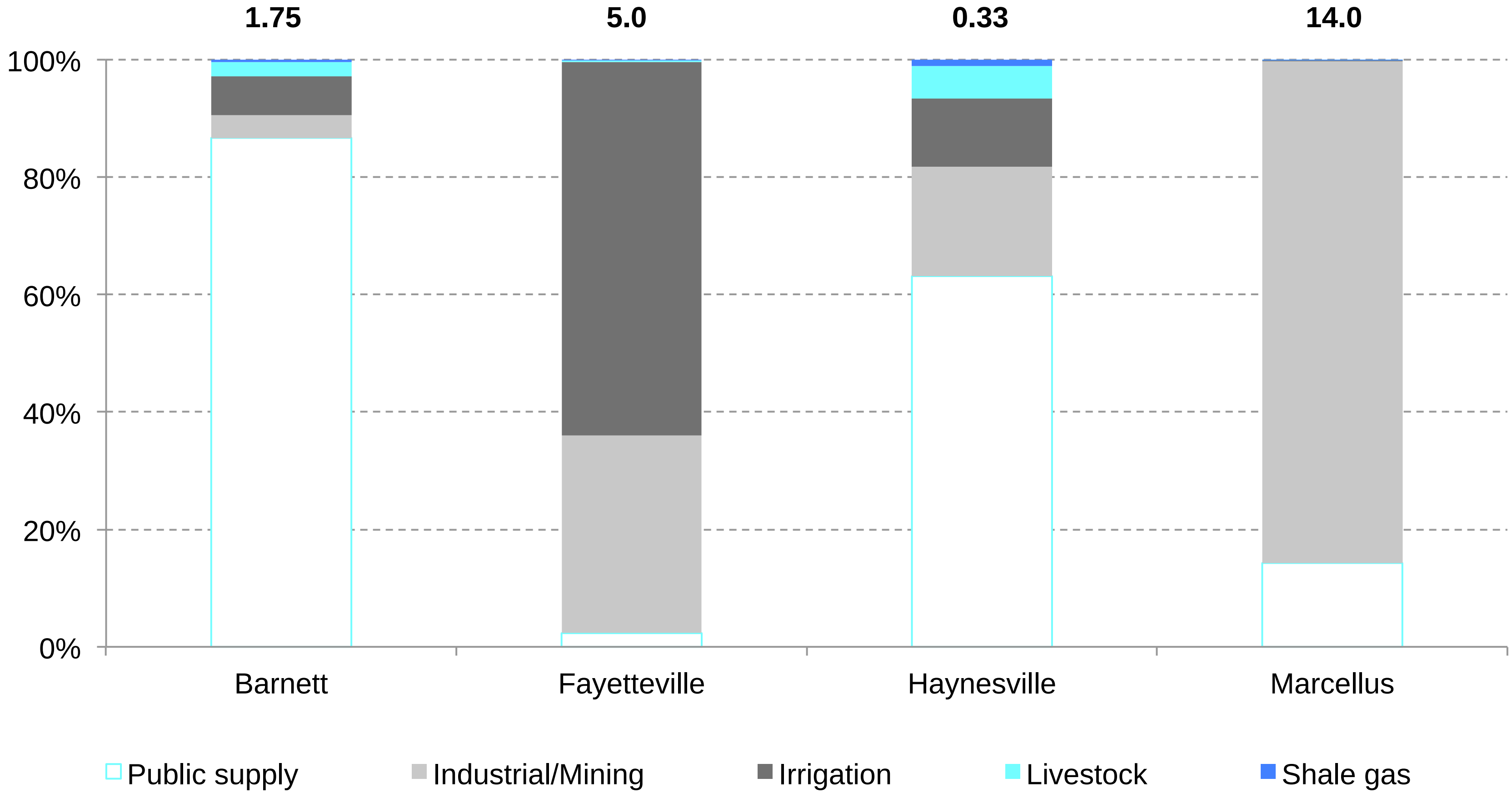
Basin	Depth to shale (ft)	Depth to aquifer (ft)
Barnett	6,500 – 8,500	1,200
Fayetteville	1450 – 6,700	500
Marcellus	4,000 – 8,500	850
Woodford	6,000 – 11,000	400
Haynesville	10,500 – 13,500	400

Shale gas resources are separated from freshwater aquifers by 1,000s of feet of alternating layers of siltstones, shales, sandstones

1 "Modern Shale Gas: A Primer," United States Department of Energy, April 2009
Source: MIT gas supply team

There is wide variation in water use both within and between shale plays – Although shale gas is 4-6X more water intensive than conventional gas, the volume of water needed is rarely the issue

2008 water consumption by type in the major shale gas plays[2]
Percent of total, Billions of M^3 per year

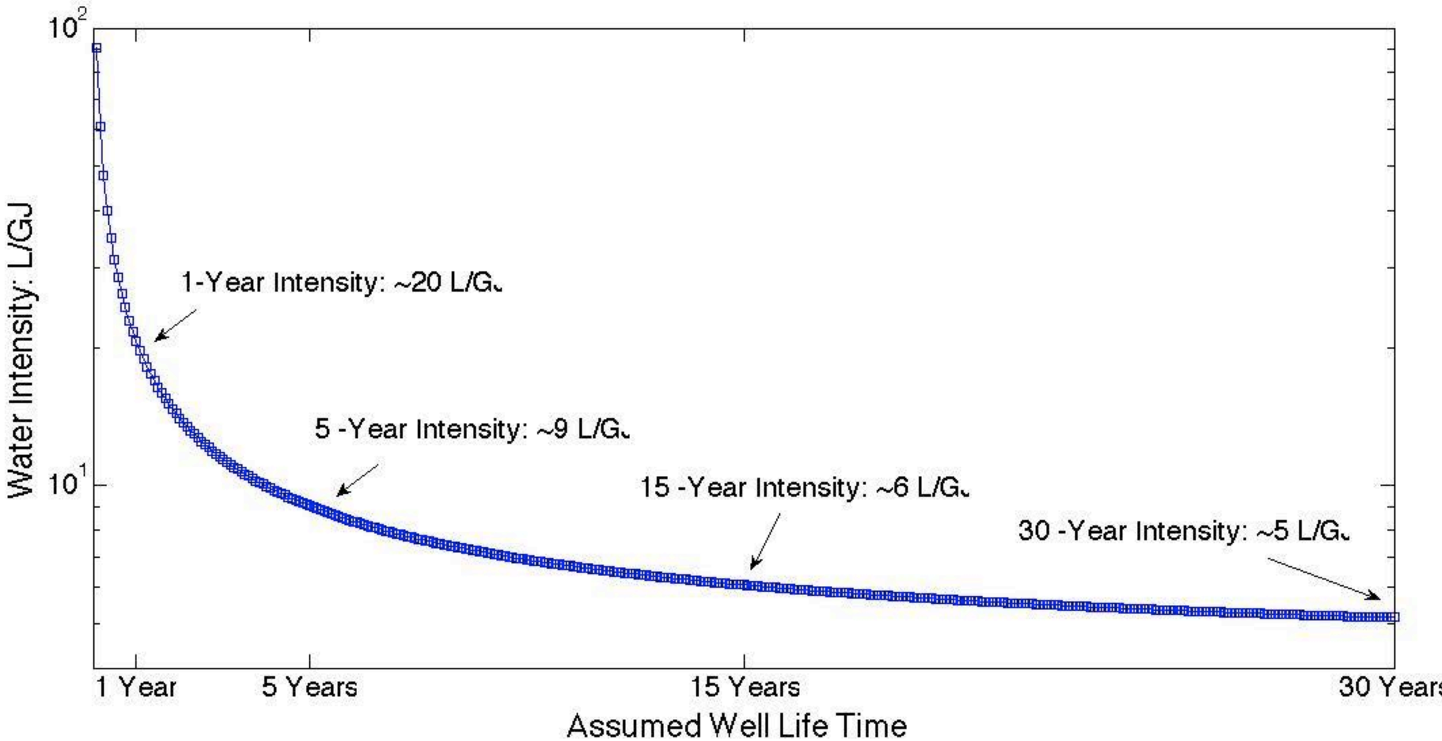


1. Based on 2009 well performance data and assuming 30-year EUR estimates
2. "Modern Shale Gas in the United States: A Primer," United States Department of Energy, 2009

Source: MIT/UT ESC team

Life cycle water intensity metric mask an extreme temporal asymmetry in water input versus energy production – Thoughtful assessments of fracturing water intensity needs to consider this temporal feature

Illustration of how the water intensity of hydraulic fracturing changes relative to the temporal horizon

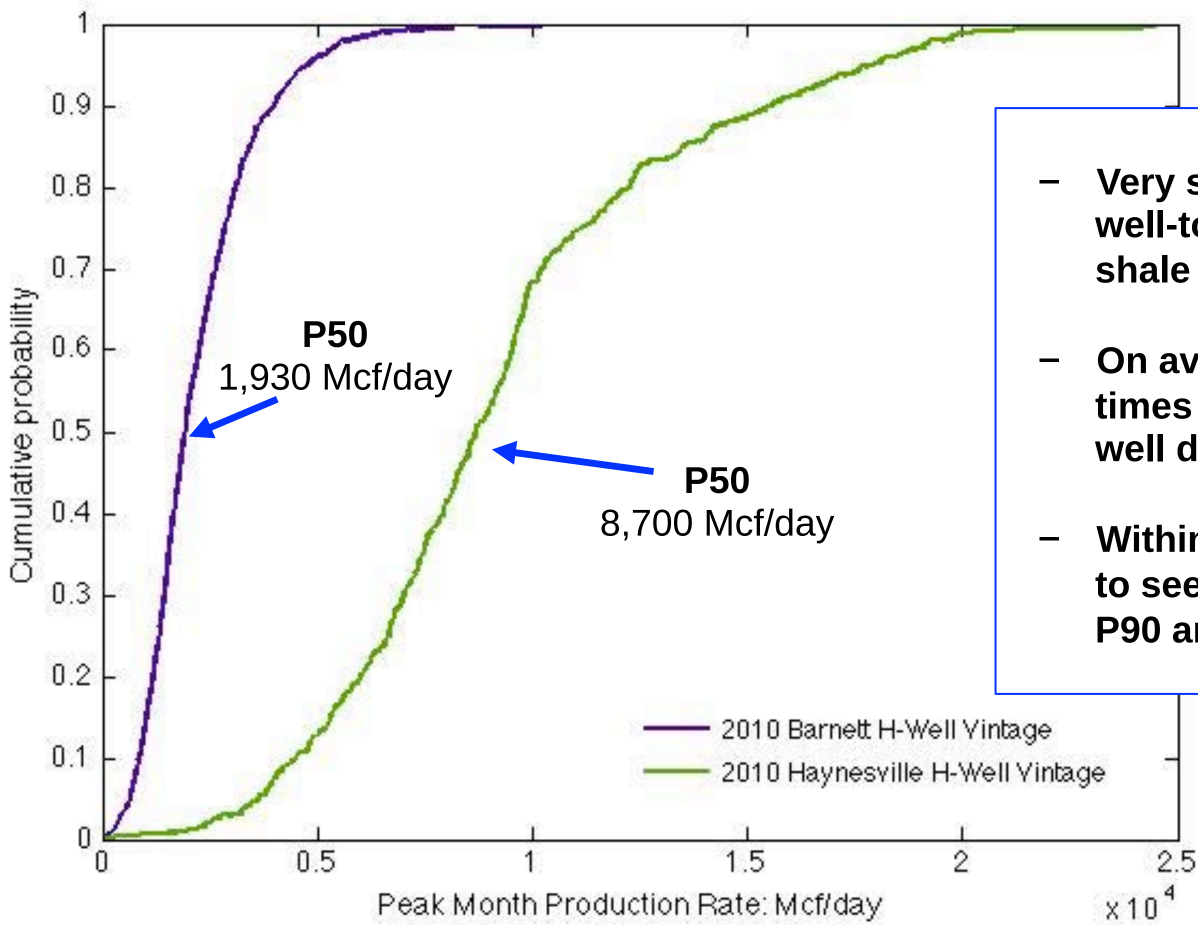


- Re-fracturing must be considered if you wish to use the life cycle metric
- Re-fracturing experience to date suggest a specific intensity in the 14-18 L/GJ range for the incremental energy production

Source: F. O'Sullivan

Fugitive GHG emissions, particularly those from hydraulic fracturing are a major issue, and rightly so – To date the analysis has been hampered by poor data and a lack of insight into field practice

Distribution of peak month well productivity in Barnett and Haynesville shales[1]
All horizontal shale wells drilled in Barnett and Haynesville Shales during 2010



- **Very significant variation is evident in well-to-well performance of all the main shale plays**
- **On average a Haynesville well will be 4-5 times more productive than a Barnett well during the first few months**
- **Within all the main plays you can expect to see at least a 3.5X difference between P90 and P10 well productivity**

1. Peak month production rate reported in units of Mcf/day
Source: HPDI production database

How gas is handled at the wellhead immediately after hydraulic fracturing is the critical factor – The GHG impact of any given well completion can vary by an order of magnitude depending on how those potential emissions are handled

The options for gas handling during shale well completion operations

Cold-Venting

- Direct release of natural gas to atmosphere
- 13.5 kg CO_2e / m^3 of natural gas

Flaring

- Burn the natural gas as it is released
- 1.7 kg CO_2e / m^3 of natural gas[1]

Reduced Emissions "Green" Completion

- Capture and deliver gas to gathering system
- 1.3 kg CO_2e / m^3 of natural gas[2]

1 Assuming 98% combustion efficiency per U.S. EPA
2 Assuming 90% of natural gas is captured by system

Analyzing gas handling scenarios reveals how easy it is to arrive at differing conclusions regarding the GHG intensity of shale well completions

Per-well fugitive GHG emissions intensity based on 2010 play-level mean well performance, and assumptions in scenarios A-D for gas handling during well completion
Mg CO_2e per well assuming 100 year GWP of 25 for CH_4

	Barnett	Fayetteville	Haynesville	Woodford	Marcellus
Scenario A 100% Vented	3,669	3,978	15,816	6,544	5,442
Scenario B 49% Vented, 51% Flared	2,036	2,208	8,779	3,632	3,021
Scenario C 3% Vented, 4% Flared, 93% GC	470	510	2,026	838	697
Scenario D 15% Vented, 15% Flared, 70% GC	877	951	3,782	1,565	1,301

- The differences in inter-play average well performance levels means that for any gas handling scenario, the GHG intensity of a “typical” well could vary by a factor of >4X

- The GHG intensity could vary by almost 8X depending on which gas handling scenario is assumed to be “representative” of field practice

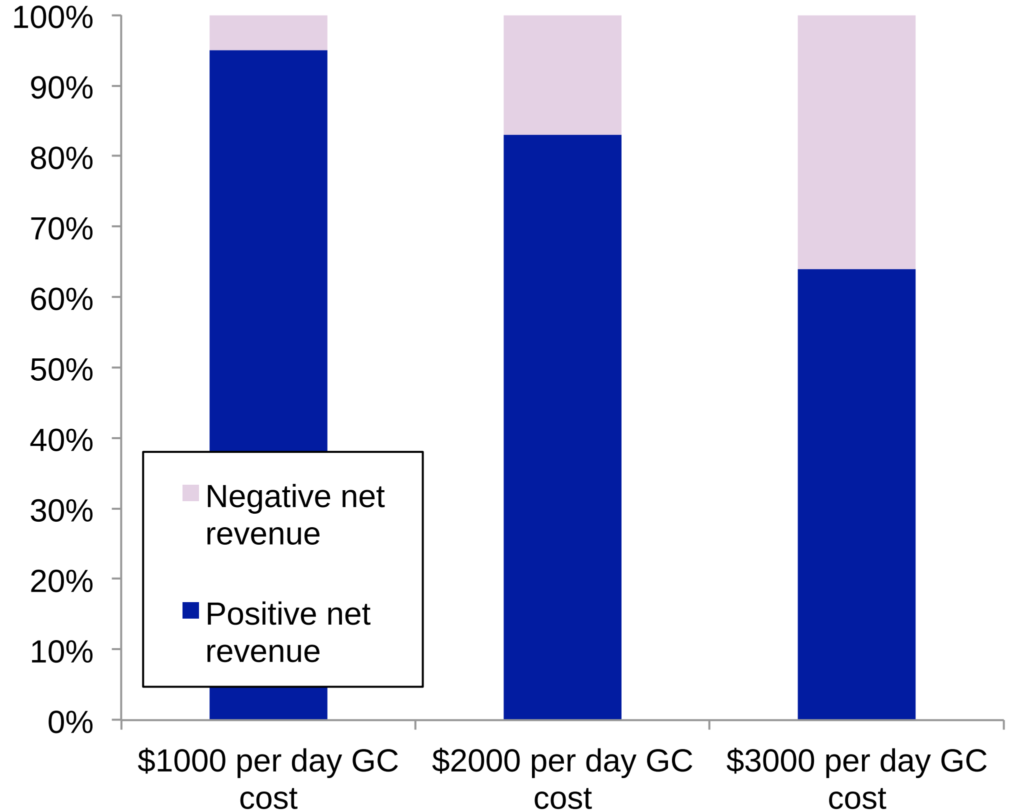
Source:F. O’Sullivan & S. Paltsev, “Shale gas production: potential versus actual GHG emissions,” *Environmental Research Letters*, 7 044030, 2012

Minimizing fugitive emissions during shale gas well-completion is a value creating activity for operators – It is hard to see a reason why green completion techniques should not be required for all shale wells

Shale development model aligns well with the use of green completion techniques

- Access to gas gathering systems during the well completion process is common
- High flowback gas production rates mean significant value lost if gas is vented or flared
- Multi-well pad operations enable high levels of operational efficiency

Economic attractiveness of using green completions in the Barnett shale[1]
% of wells completed during 2010 assuming $4.00/Mcf



1 Assuming $4.00/Mcf wellhead gas price, 9 day flowback duration and average flowback production rate equal to 0.5 IP rate
Source: F. O'Sullivan & S. Paltsev, "Shale gas production: potential versus actual GHG emissions," Environmental Research Letters, 7 044030, 2012, HPDI Production Database