Current and Projected Natural Gas Markets

for
Council of Industrial Boiler Owners
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Outline

- Current natural gas market conditions.
- Annual Energy Outlook 2012 natural gas projections.
- Shale gas well heterogeneity and uncertainty.

Current natural gas market conditions

Current natural gas prices

"And what I can tell you is the cost to supply is not $2.50. We are all losing our shirts today. You know, we're making no money. It's all in the red."

Rex Tillerson
ExxonMobil CEO
June 27, 2012
Council on Foreign Relations

El Paso Corp. data implies that Eagle Ford dry gas production revenues cannot cover a significant portion of its well drilling and completion costs at current prices ($2.80/MMBtu Henry Hub).

	NORTHERN ACREAGE (Oil)	CENTRAL ACREAGE (Oil)	SOUTHERN ACREAGE (Dry Gas)
Overview			
Objective	Eagle Ford Shale	Eagle Ford Shale	Eagle Ford Shale
Depth	6,000'–7,000'	7,000'–10,000'	9,000'–14,000'
Lateral Length:	4,500'–5,500'	4,500'–5,500'	4,500'–5,500'
Capital costs:	$5.0–$7.5 MM	$7.0–$9.0 MM	$7.0–$12.0 MM
EUR (Gross):	400–550 MBOE	400–900 MBOE	4.0–8.0 Bcfe
Initial prod:	400–800 BOED	600–1,100 BOED	5–15 MMcfe/d
IP (30):	300–600 BOED	400–900 BOED	4–12 MMcfe/d
Metrics ($4.00/MMBtu, $80/Bbl)			
IRR:	25%–45%	25%–>50%	0%–15%
PVR:	1.20–1.40	1.20–1.50	0.85–1.0
F&D costs:	$14–$22 ($/BOE)	$12–$20 ($/BOE)	$1.50–$3.50 ($/Mcfe)

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Note: Capital, Production and EUR are gross numbers and do not account for royalties

El Paso slide nomenclature

EUR = “Estimated Ultimate Recovery” = cumulative production over the life of the well

IP(30) = Average daily production rate for the first 30 days; note the wide variation of 4 - 12 MMcfe per day. (EUR is highly correlated with IP(30), so EUR range might be understated.)

F&D Costs = Finding and Development Costs = cash cost of well drilling and completion; includes lease purchase costs, but not debt interest payments, taxes, or royalties.

IRR = Internal Rate of Return

What El Paso is implicitly telling us

- At $4/MMBtu wellhead gas price, some of their Eagle Ford shale gas wells will have zero return on investment.

- Given that royalties run between 12% to 20%, the wellhead gas price needed to make sufficient profits and to pay for royalties, interest, and taxes is about $5 to $6/MMBtu, especially given the wide variation in shale gas well productivity.

- Assuming a $1/MMBtu cost to gather, process, and transport gas to final consumers results in $6 to $7/MMBtu delivered.

Recent Gas Market Behavior

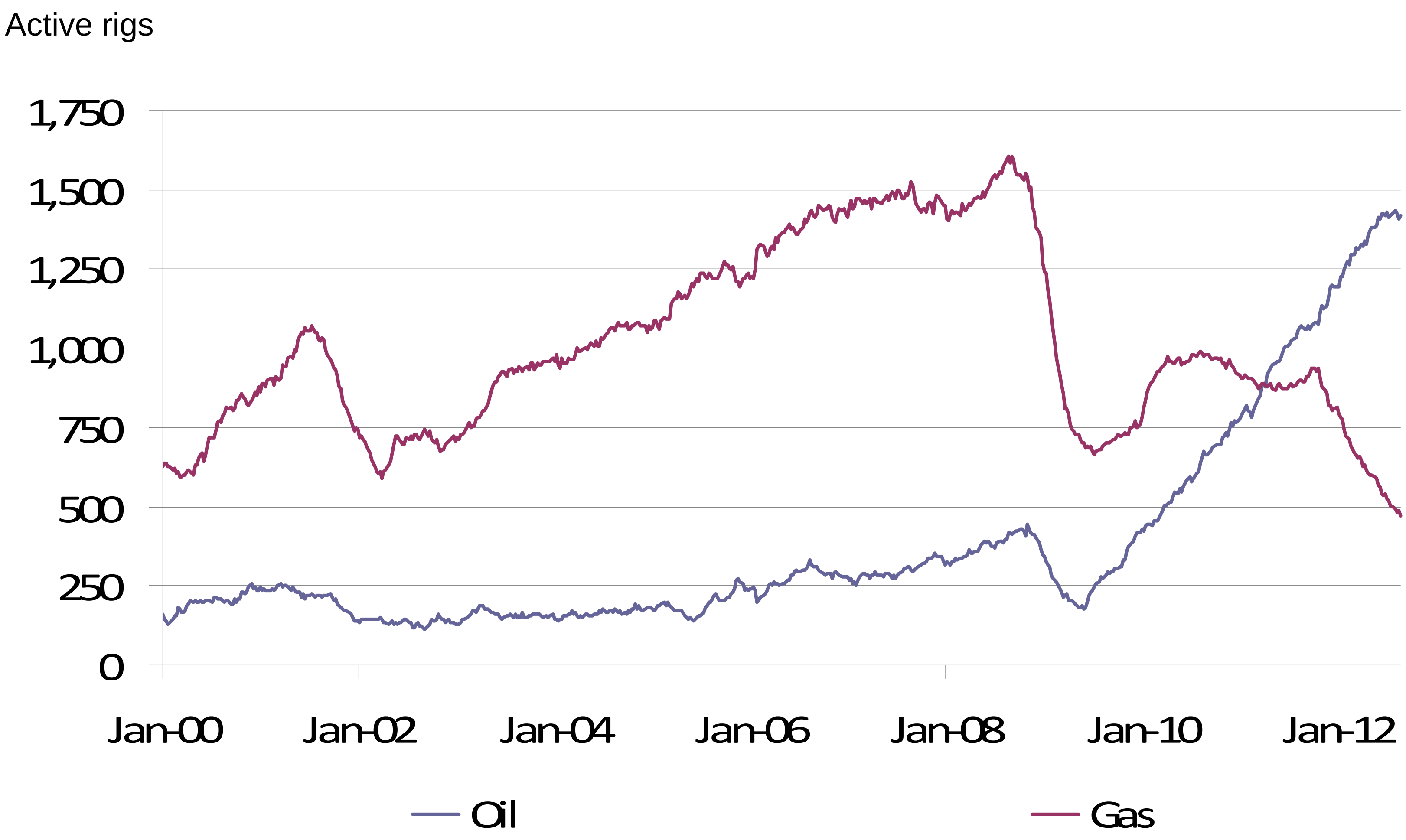
- As natural gas prices rose in the mid-2000's, natural gas producers were infected by "gold fever," buying up more leases and drilling more wells than were necessary to supply the market.

- Over capacity led to a rapid decline in gas prices after 2008.

- The mild 2011-2012 winter left a large inventory of gas in storage. This overhang resulted in gas prices temporarily below $2/MMBtu in the Spring of 2012.

- Producers have moved their drilling activities to "tight" oil production, but a large proportion of this production is in the form of methane (20% to 40% of the total "barrel").

Oil and natural gas drilling rig count



Source: Baker-Hughes

Natural gas and tight oil production

- Tight oil production requires natural gas to drive the fluids to the wellbore, a.k.a. “reservoir drive.”

- Tight oil production is typically:

  - 1/3 methane,
  - 1/3 natural gas liquids (ethane, propane, butane),
  - 1/3 condensates and oil.

- Although producers financially benefit from liquids production, due to their higher prices, natural gas liquid (NGL) prices have been declining over the last year due the high level of tight oil drilling and production. NGL prices were historically 55% - 70% of the WTI oil price; now down to ~43%.

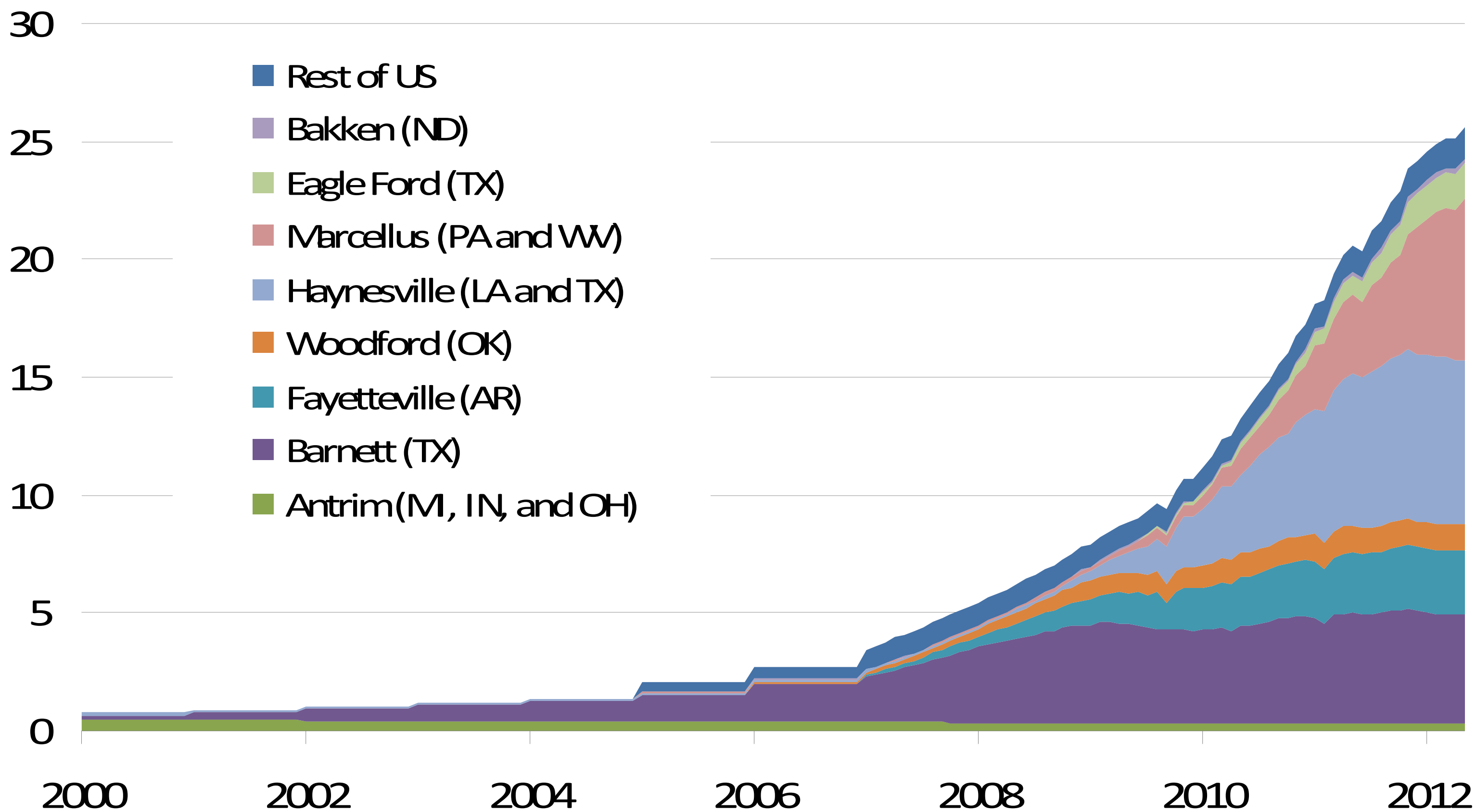
How long will low natural gas prices continue?

Difficult to determine; depends on such factors as:

- 1) future gas well drilling activity; how rapidly and to what level does gas rig activity decline.
- 2) future tight oil drilling activity; depends upon how low NGL prices fall and how high oil prices stay,
- 5) growth in natural gas electricity generation capacity,
- 6) how soon and how much liquefied natural gas (LNG) is exported (or not),
- 7) availability of bank credit and investor money,
- 8) future U.S. economic activity, which plays a large role in determining industrial and electric power gas consumption growth.

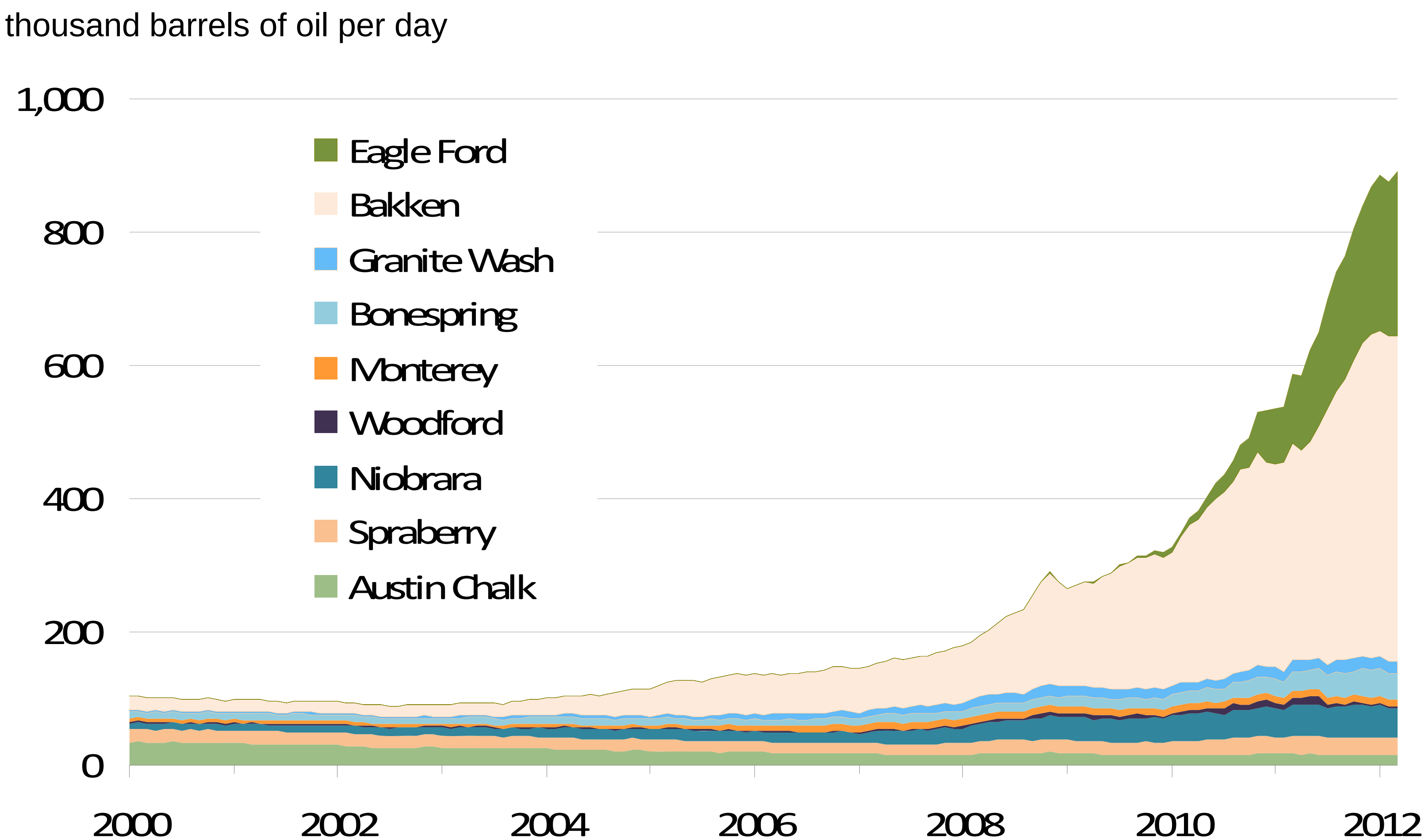
U.S. shale gas production comprised over 30 percent of total U.S. dry production, in 2011

shale gas production (dry)
billion cubic feet per day



Sources: Lippman Consulting, Inc. gross withdrawal estimates as of May 2012 and converted to dry production estimates with EIA-calculated average gross-to-dry shrinkage factors by state and/or shale play.

Tight oil production for selected plays in March 2012 approaches 900,000 barrels per day



Source: HPDI, Texas RRC, North Dakota department of mineral resources, and EIA, through March, 2012.

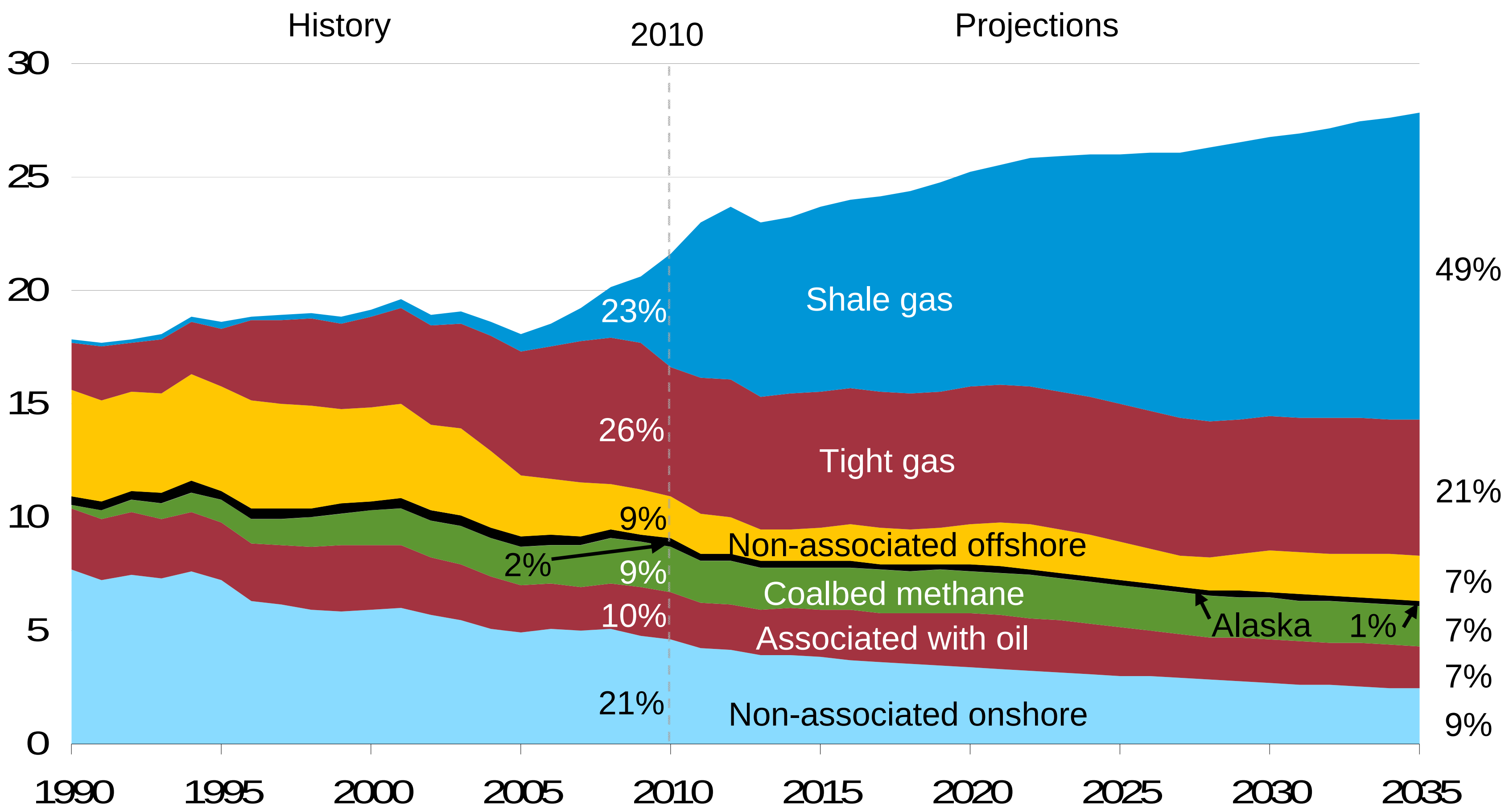
AEO2012 natural gas market projections

EIA natural gas model dynamics

- Natural gas prices largely driven the marginal cost of new natural gas production.
- As the lower cost gas deposits deplete, the marginal cost of new production increases over time.
- Technological innovation is represented by reducing well drilling and completion costs at the industry's historic rate.
- Model assumes "normal" weather and inventory storage.
- Model assumes industry is a "rationale actor," which precludes drilling booms and busts.

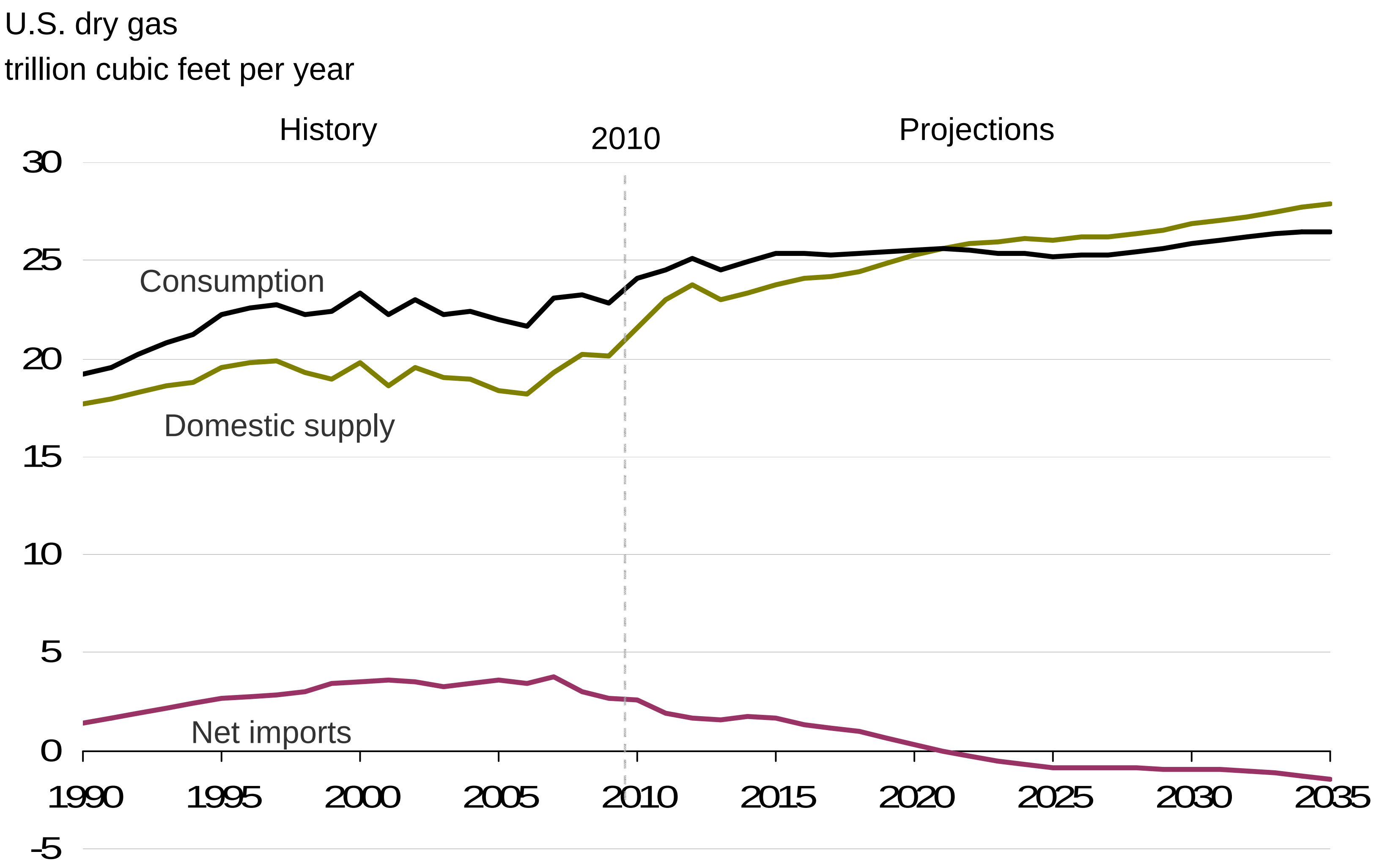
Shale gas offsets declines in other U.S. natural gas production sources

U.S. dry gas production
trillion cubic feet per year



Source: EIA, Annual Energy Outlook 2012 , Reference Case

Domestic natural gas production grows faster than consumption



Source: EIA, Annual Energy Outlook 2012 , Reference Case

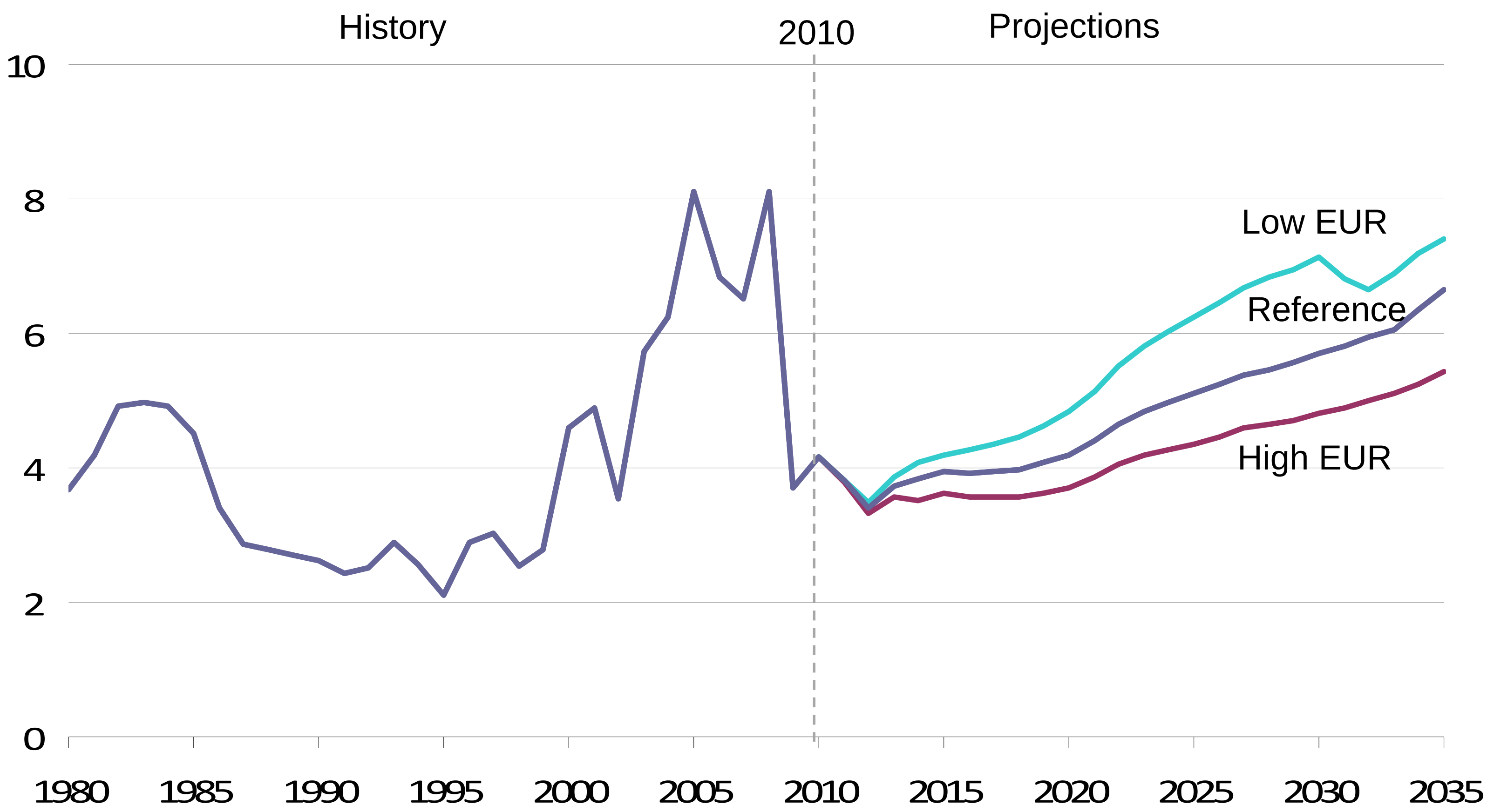
Testing U.S. shale gas resource uncertainty

- The *Low Estimated Ultimate Recovery (EUR)* case assumes that the EUR per shale gas well is 50 percent lower than in the Reference case. The total unproved shale gas resource is decreased to 241 trillion cubic feet, compared to 482 trillion cubic feet of shale gas in the Reference case.

- The *High EUR* case assumes that the EUR per shale gas well is 50 percent higher than in the Reference case. The total unproved shale gas resource is increased to 723 trillion cubic feet.

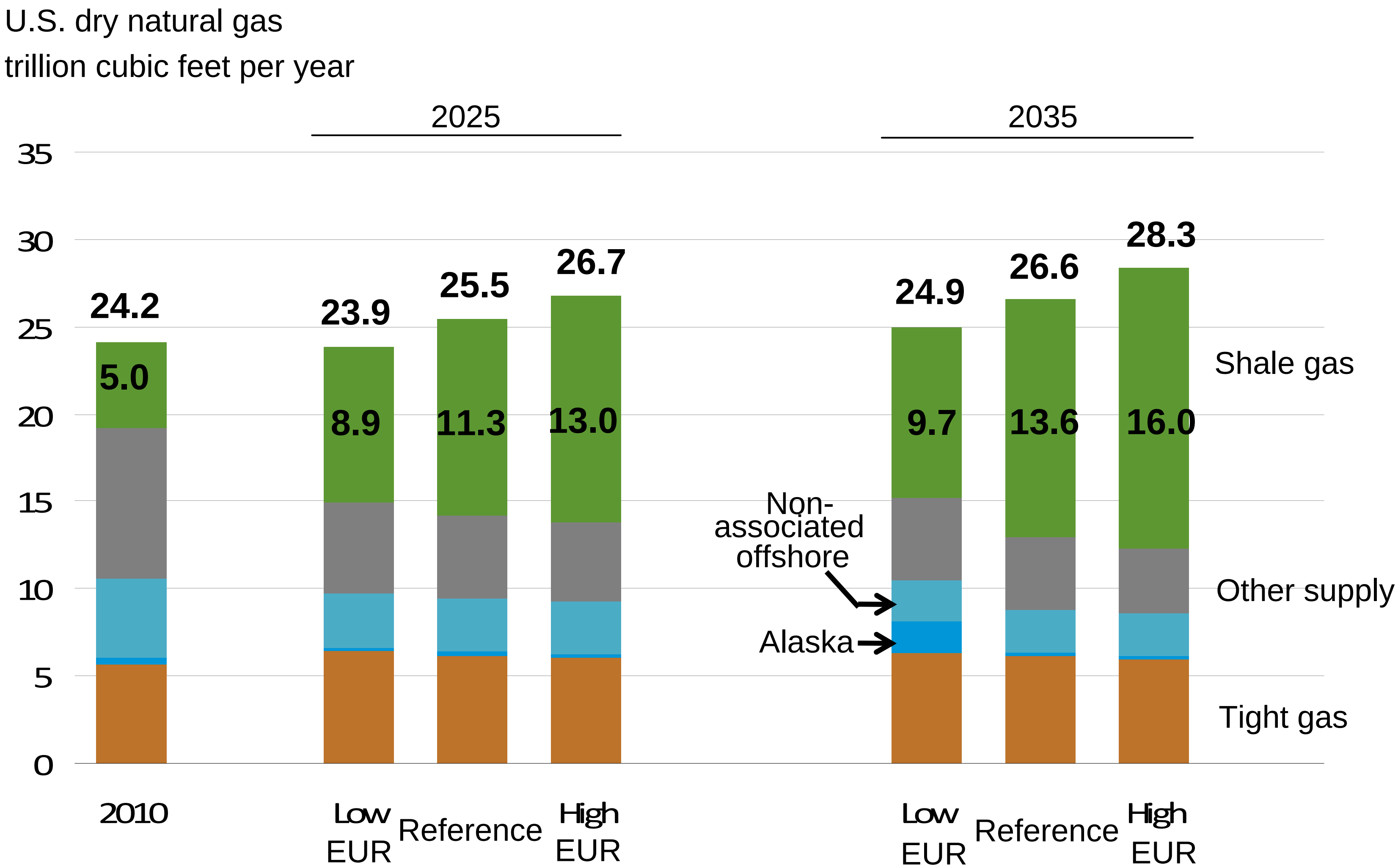
Natural gas price projections vary based on shale gas resource base assumptions

lower-48 average natural gas wellhead price
2010 dollars per thousand cubic feet



Source: EIA, Annual Energy Outlook 2012

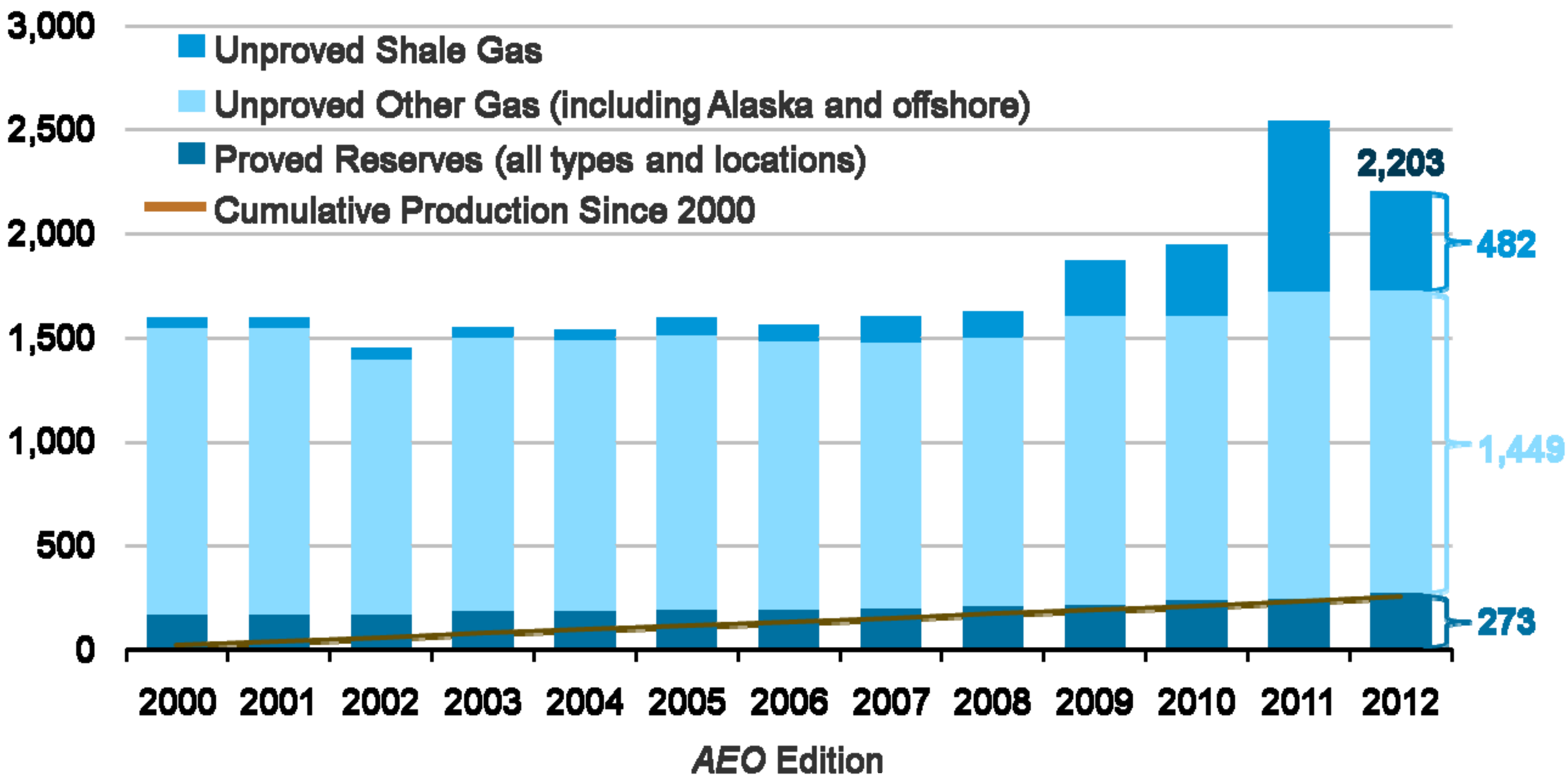
Uncertainty surrounding shale gas resource estimates can result in significantly different futures for natural gas production.



Source: EIA, Annual Energy Outlook 2012

Technically recoverable dry gas resource estimates change over time

U.S. dry gas resources
trillion cubic feet



Source: EIA, Annual Energy Outlook 2012, Reference Case

Shale gas well heterogeneity and uncertainty

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.
- Most shale wells are relatively young; their long-term productive capability is unknown
- Future improvements in technology cannot be anticipated.

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

- 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.

Long horizontal laterals reduce uncertainty

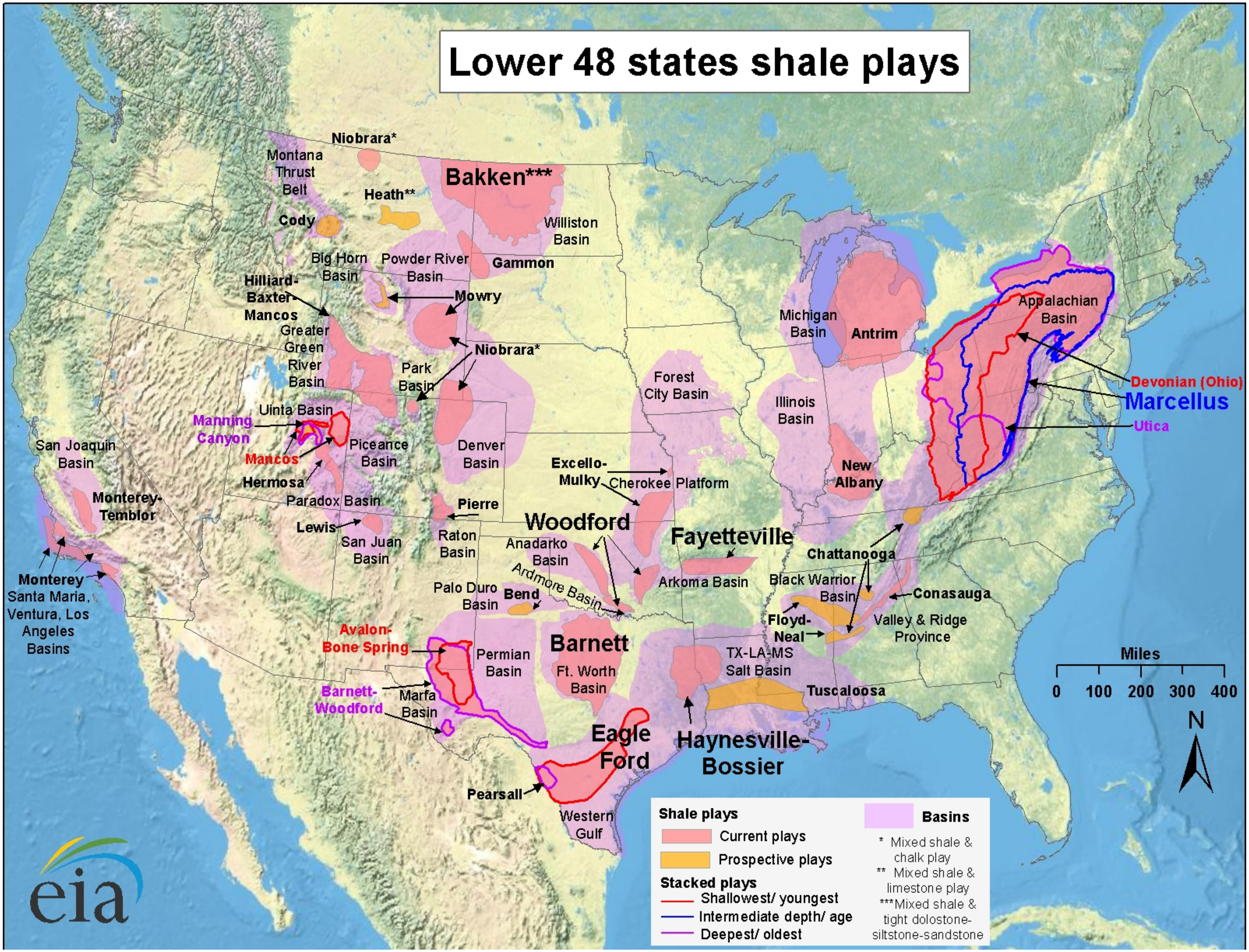
Significant heterogeneity within each shale gas well. In a shale gas well with 15 hydraulic fracturing stages:

- 5 stages might produce 60% of the total gas volume
- 5 stages might produce 30% of the total gas volume
- 5 stages might produce 10% of the total gas volume

Long horizontal laterals are one way reduce production risk.

“Dry holes” do occur, but infrequently. Dry holes occur when operating costs exceed production revenues.

Long laterals with many frack stages increase well costs.



Lower 48 states shale plays
Niobrara*
Montana Thrust Belt
Bakken***
Heath**
Cody
Williston Basin
Big Horn Basin
Powder River Basin
Gammon
Hilliard-Baxter-Mancos
Mowry
Greater Green River Basin
Niobrara*
Park Basin
Uinta Basin
Manning Canyon
Mancos
Piceance Basin
Denver Basin
Hermosa
Paradox Basin
Pierre
Lewis
San Juan Basin
Raton Basin
San Joaquin Basin
Monterey-Temblor
Monterey
Santa Maria, Ventura, Los Angeles Basins
Forest City Basin
Excello-Mulky
Cherokee Platform
Woodford
Anadarko Basin
Ardmore Basin
Fayetteville
Arkoma Basin
Palo Duro Basin
Bend
Avalon-Bone Spring
Permian Basin
Barnett
Ft. Worth Basin
Barnett-Woodford
Marfa Basin
Eagle Ford
Pearsall
Western Gulf
Haynesville-Bossier
TX-LA-MS Salt Basin
Tuscaloosa
Michigan Basin
Antrim
Illinois Basin
New Albany
Black Warrior Basin
Chattanooga
Conasauga
Floyd-Neal
Valley & Ridge Province
Appalachian Basin
Devonian (Ohio)
Marcellus
Utica
Miles
0 100 200 300 400
N
Shale plays
Current plays
Prospective plays
Stacked plays
Shallowest/ youngest
Intermediate depth/ age
Deepest/ oldest
Basins
* Mixed shale & chalk play
** Mixed shale & limestone play
***Mixed shale & tight dolostone-siltstone-sandstone

For more information

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