Assumptions and Expectations for *Annual Energy Outlook 2014:* Oil and Gas Working Group

AEO2014 Oil and Gas Supply Working Group Meeting

Office of Petroleum, Gas, and Biofuels Analysis

July 25, 2013 | Washington, DC

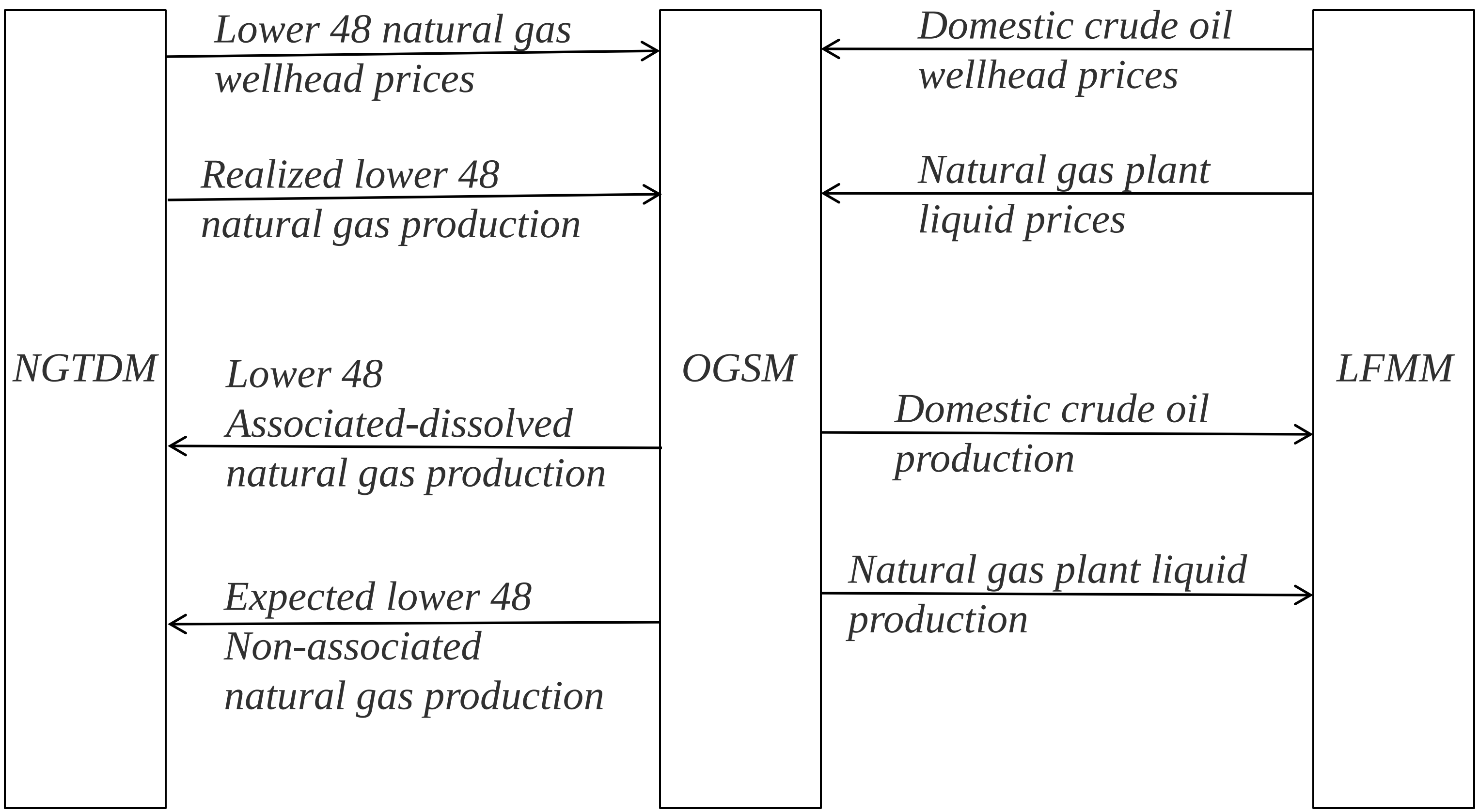
http://www.eia.gov/forecasts/aeo/workinggroup/

WORKING GROUP PRESENTATION FOR DISCUSSION PURPOSES
DO NOT QUOTE OR CITE AS RESULTS ARE SUBJECT TO CHANGE

Introduction/Background

- Working group (history, purpose)
- National Energy Modeling System (NEMS)
  - Annual Energy Outlook
  - Requested service reports
  - Assumptions/Documentation
  - Model code and data input files
- Natural gas, petroleum, and biofuels modules
  - Oil and Gas Supply Module (OGSM)
  - Natural Gas Transmission and Distribution Module (NGTDM)
  - Liquid Fuels Market Module (LFMM)
    - Formerly Petroleum Market Module (PMM)
    - Discussed in earlier working group

Primary data flows between oil and gas modules of NEMS



Assumptions
Natural Gas Transmission and Distribution Module (NGTDM)

Overview

- Benchmark model to average regional historical hub prices
- Endogenously set exports from U.S. to Canada
- Reassess assumptions related to consumption and production in Mexico, and therefore exports to Mexico from the United States
- Reevaluate assumptions related to LNG exports out of U.S. and Canada
- Reestimate distributor tariffs and Canada supply equations
- Natural gas used in trains and ships is now included in NEMS

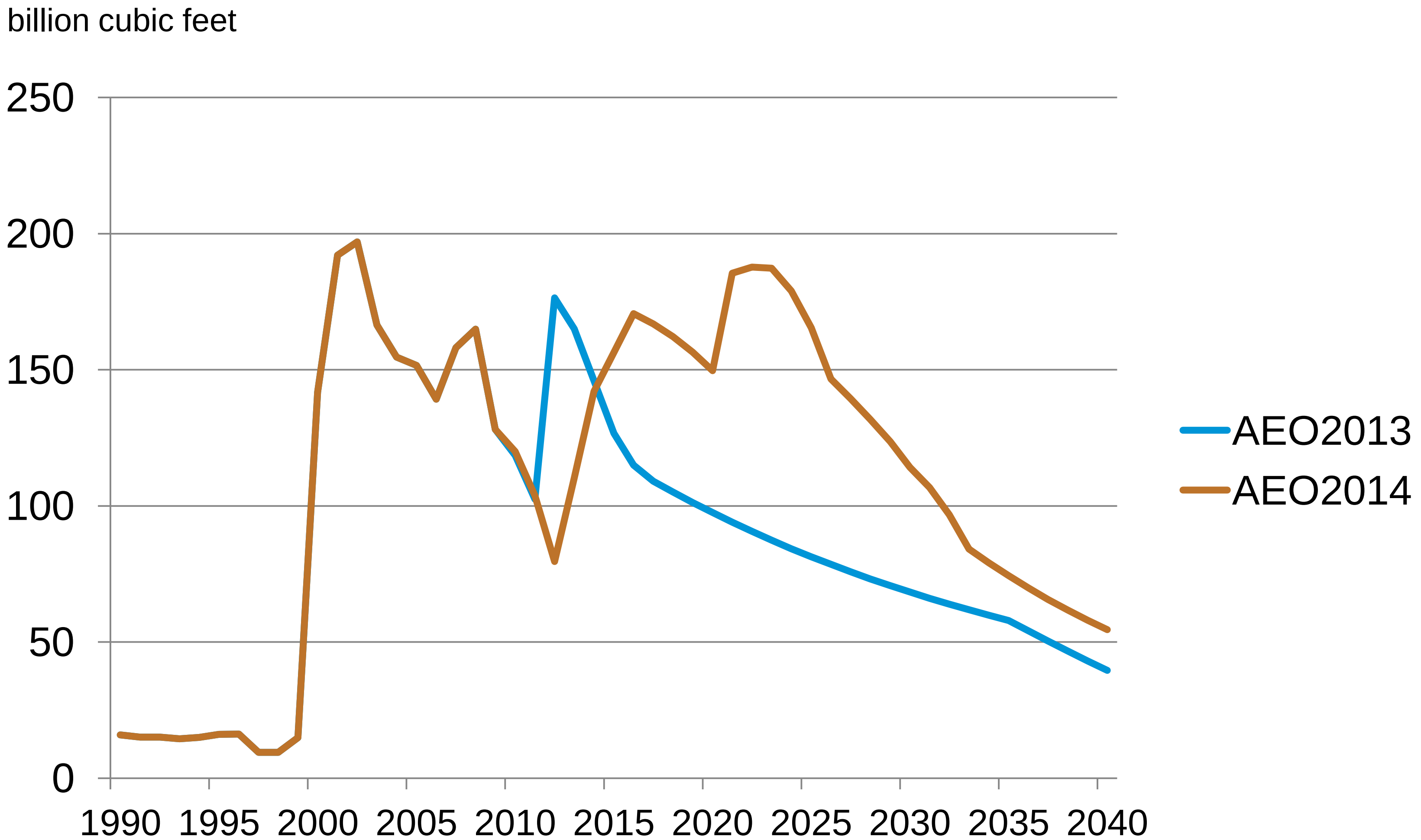
Regional natural gas pricing

- Previously the NGTDM was effectively benchmarked at the wellhead and city gate level
- With the pending discontinuation of the reporting of historical wellhead prices, for AEO2013 regional wellhead prices were replaced with representative spot prices less gathering charge
- For AEO2014, wellhead prices will be set as a netback from the regional hub price and hub prices will be benchmarked to representative historical spot prices
- While residential and commercial prices will still see a distributor markup off of the citygate price, industrial and electric generator prices will be marked up off of the regional hub price

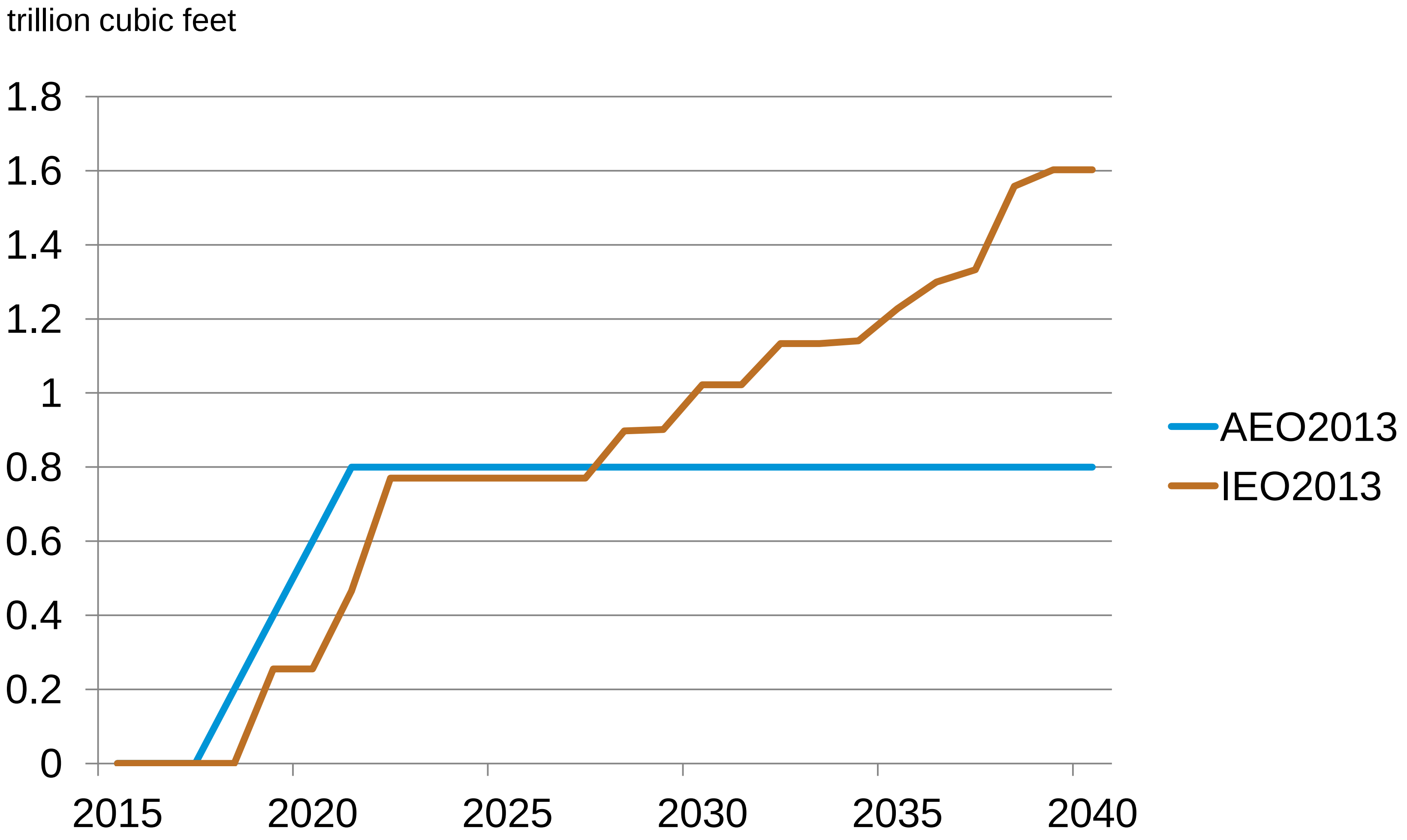
Canada

- Exports from eastern U.S. to Canada, which had been set exogenously, now set endogenously based on relative prices. Expect volumes in same range (1.4 Tcf by 2040 in AEO2013).
- Eastern Canada production still exogenous, based on assumptions about offshore projects
- Western Canada production --update with new data, reestimate
- For AEO2013, LNG exports endogenous, draw from W. Canada market and based on W. Canada price, limited to 800 Bcf/y.
- For AEO2014, set exogenously consistent with IEO2013, assumed to draw from stranded resources (i.e., no influence W. Canada price)

Eastern Canada natural gas production, exogenous projection



Eastern Canada natural gas production, exogenous projection



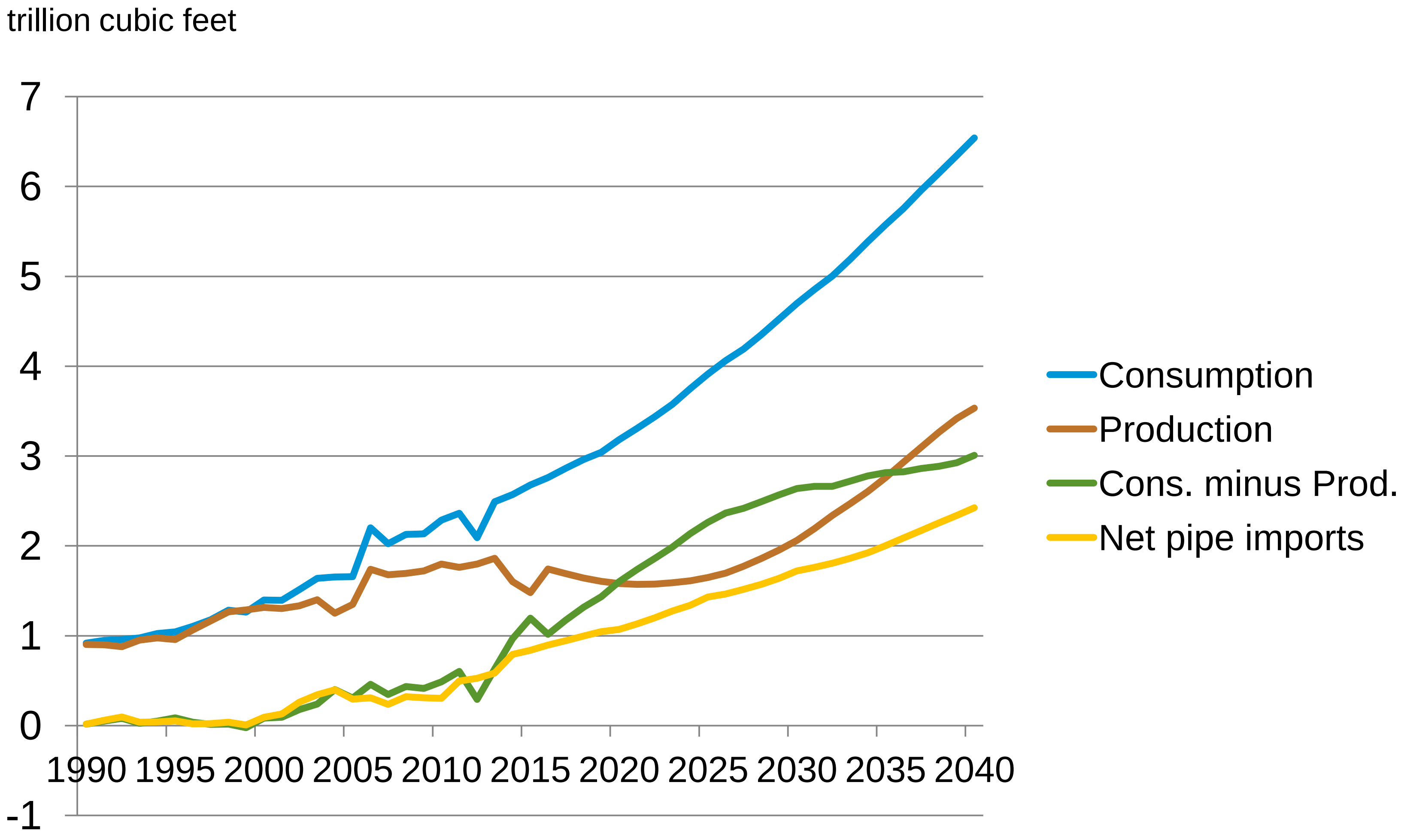
Mexico

- Expect exports to Mexico from the U.S. to be higher in AEO2014 compared to AEO2013, largely due to lower LNG imports into Mexico. Will depend on timing of infrastructure to support.

- Consumption set exogenously based on IEO2013 levels, higher towards the end of the forecast (in 2040, 6.0 Tcf in AEO2013 versus 6.5 Tcf in IEO2013).

- While production is set endogenously it is based on IEO2013 projections. If anything, will be slightly lower than IEO2013 levels.

IEO2013 Mexico natural gas consumption and production AEO2013 net pipeline imports to Mexico from U.S.



LNG exports of domestically produced gas

- Minimum export levels set based on assessment of high likelihood of project going forward given reported project status.
  - Plan to set minimums consistent with four trains at the Sabine Pass facility

- Model assesses the economic viability of a project based on a 20-year net present value assessment of the difference between the fully loaded price for natural gas from the U.S. as delivered to the Europe and Asia versus the estimated market price in the two areas.

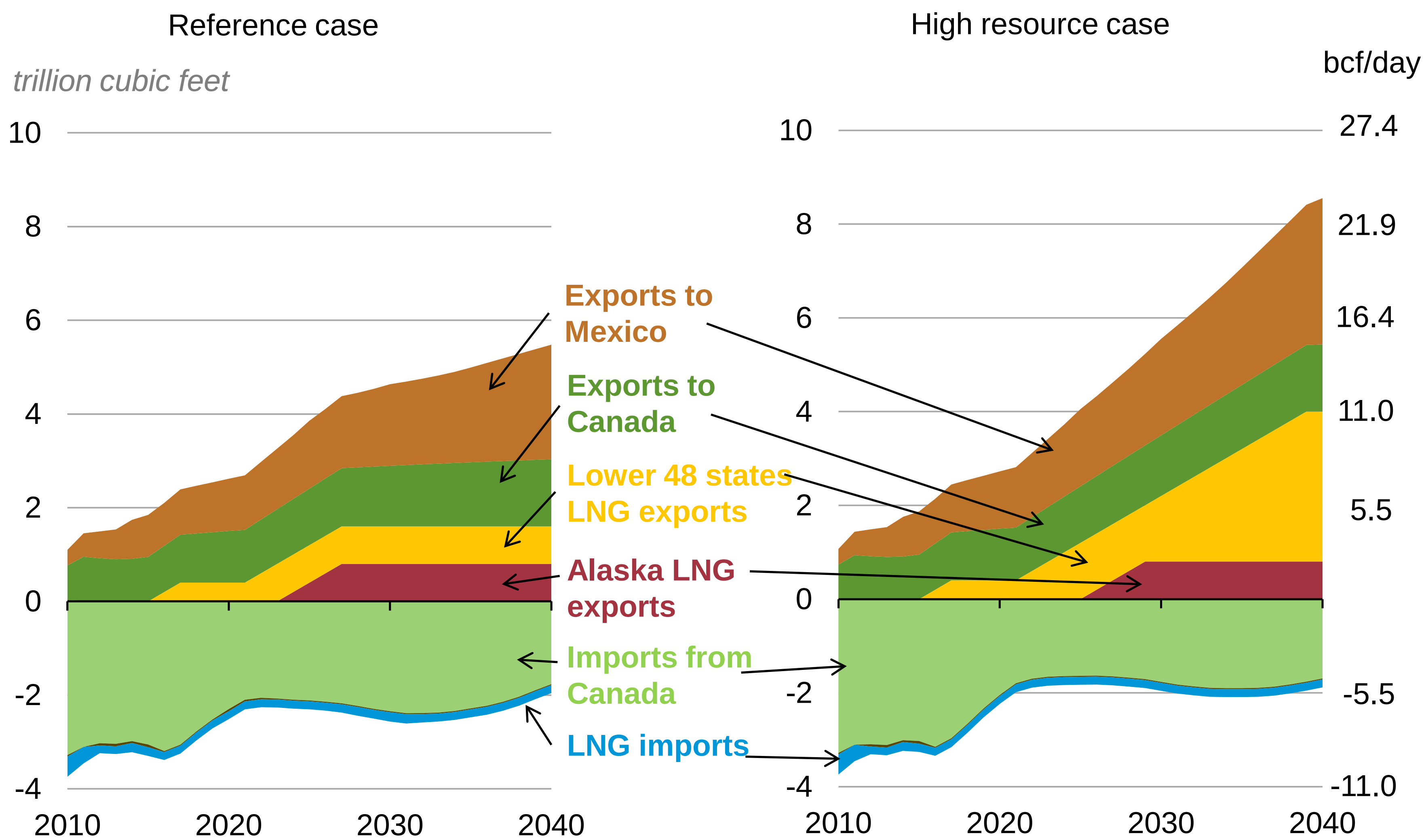
- Each project will consist of two 200 Bcf/y trains, with a limit of one (?) train built in the lower 48 states in a given forecast year.

- If a liquefaction facility is built by the model, it will be assumed that it is used to full operating capacity thereafter.

Charges and assumptions related to LNG exports for AEO2013

(2010$/MMBtu)	**S. Atlantic**	**W.S. Cntl**	**WA/OR**	**Alaska**
Liquefaction and Pipe Fee	3.30	3.00	4.10	7.00
Shipping to Europe	0.98	1.28	3.86	3.65
Shipping to Asia	2.63	2.55	1.15	0.90
Regasification	0.10	0.10	0.10	0.10
Fuel charge (percent)	15	15	15	15
Nonfuel markup to Europe	4.38	4.38	8.06	10.75
Nonfuel markup to Asia	6.03	5.65	5.35	8.00
Risk	0.00	0.00	0.00	0.00
Maximum exports (Bcf)	9999	9999	9999	800
Earliest start year	2019	2018	2019	2023

U.S. natural gas imports and exports, AEO2013



Contacts

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General oil and gas questions | angelina.larose@eia.gov

Assumptions
Oil and Gas Supply Module (OGSM)

Overview

- Introduction/background
- Oil and natural gas supply assumptions
  - Alaska
  - Offshore
  - CO2 EOR
  - Drilling cost equations
  - Lower 48 continuous plays
    - county level evaluation
- Side cases/Issues in focus
  - pending tax change legislation
  - high resources; same as last AEO?

Goals for AEO2014

- Streamline I/O system for historical data by transitioning from Fortran to SAS
- Reporting of NGPL technically recoverable resources
- New drilling cost equations
- Tight oil and shale gas EURs at county level, improves granularity
- Improved interfaces with LFMM and EMM

Challenges/issues

- Data no longer available for historical updates
  - Wells completed (IHS & EIA)
  - Lease equipment & operating costs (EIA)
  - Drilling costs (JAS)
  - What's next?
- DI database play name aliases and type (LP, SH) designations
  - Definition consistent with monthly generated production charts
  - Clean up play names in additional tight and shale plays
- Nehring reservoir database 2007 version
  - API gravity, Sulfur, Depth, temperature, maturity, porosity, CO_2 content, NGPL factor

Alaska

Alaska North Slope shale oil production potential

- U.S. Geological Survey assessment (February 2012)
- Activities to-date
- Constraints to the development of shale oil resources
- North Slope wellhead oil prices
- Conclusions

U.S. Geological Survey assessments of North Slope and Bakken shale oil technically recoverable resources (TRR)

Shale formation	Mean value potential production area (million acres)	Mean estimated Oil + NGPL TRR (million barrels)	Mean estimated ultimate recovery for "sweet spot" wells (thousand barrels per well)
Shublik	6.6	475	61
Brookian	17.4	471	43
Kingak	6.8	29	43
Bakken (only)	11.3	3,890	250 to 430

Sources: U.S. Geological Survey, AK North Slope - Fact Sheet 2012-3013 & Bakken – Fact Sheet 2013-3013

Alaska North Slope shale oil: activities to-date

- Great Bear Petroleum
  - leased ~500,000 acres in the shale oil “window” from the State in Oct. 2010
  - formed JV with Halliburton in Nov. 2011 to test shale “proof-of-concept”
  - JV drilled 2 wells and extracted rock cores in late 2012
  - in April 2013, said more time was needed to analyze the shale rock cores
  - no new company statements since April 2013…lack of good news to release?
- Royale Energy
  - purchased 56 State leases in December 2011 auction
  - formed JV with unnamed company in April 2013 to pay for initial shale test wells
  - no new company statements since April 2013

Source: Petroleum News, Anchorage, Alaska

Alaska North Slope shale oil: constraints to production

- Natural gas - shale oil production requires associated natural gas to provide reservoir-drive through gas expansion. Absent a market for North Slope natural gas, the co-production of natural gas imposes a re-injection cost, rather than being a revenue source, as it is in the lower-48.

- Drilling costs – North Slope shale well drilling and completion costs could be 2 times or more expensive than that experienced in the lower-48.

- Environmental – the construction of North Slope gravel roads and drilling pads is expensive due to permafrost conditions. Opposition to an extensive network of roads, drilling pads, gathering pipelines, and processing plants is expected.

Alaska North Slope shale oil: wellhead oil prices

- In 2012, the average North Slope first purchase oil price was $94.52 per barrel.

- In 2012, Brent crude oil averaged $111.63 per barrel, indicating that North Slope crude oil was selling at a $17.11 per barrel discount due to pipeline and marine transportation charges.

- If North Slope oil production continues to decline, thereby causing pipeline transportation rates to increase, then North Slope shale oil wellhead revenues per barrel would decline over time, if world oil prices stayed constant.

Source: U.S. Energy Information Administration

Alaska North Slope shale oil: conclusions

- Development of Alaska North Slope shale oil production is not expected prior to 2040 due to:

  - low expected shale oil well recovery rates,

  - high drilling, completion, and infrastructure costs,

  - discounted wellhead oil prices,

  - natural gas and frack water disposal costs, and

  - expected opposition by environmental groups.

Lower 48 Offshore

Lower 48 offshore leasing availability (no changes)

	AEO2013	AEO2014
North Atlantic	none	None
Mid Atlantic	2018	2018
South Atlantic	2018	2018
Northern & Central California	none	none
Southern California	2023	2023
Eastern GOM	2022	2022

Lower 48 offshore deepwater projects

BOEM Field Name	Nickname	Water Depth	Field Size (MMBoe)	Discovery Year	Start Year of Production
WR250	Cascade	8143	372	2002	2012*
GC683	Caesar	4457	45	2006	2012*
GC726	West Tonga	4674	372	2007	2012*
MC241	MC241	2427	45	1987	2012*
MC292	Raton South	3400	12	2008	2012*
LL400	Cheyenne East	9200	12	2011	2012*
MC199	Mandy	2478	182	2010	2012*
MC562	Isabela	6535	45	2007	2012*
MC563	Santa Cruz	6515		2009	2012*
MC519	Santiago	6500		2011	2012*
GB293	Pyrenees	2100	89	2009	2012*
WR469	Chinook	8831	372	2003	2012*
GC299	Clipper	3452	45	2005	2012*
GC490	Wide Berth	3700	89	2009	2012*
MC751	Goose	1624	45	2003	2012*
GB463	Bushwood	2700	89	2009	2013
GB506	Danny II	2800		2012	2013
GC512	Knotty Head	3557	372	2005	2013
GB782	Entrada	4690	372	2000	2014
WR029	Big Foot	5235	182	2005	2014
KC875	Lucius	7168	182	2009	2014
MC725	Tubular Bells	4334	89	2003	2014
WR678	St. Malo	7036	372	2003	2014
WR759	Jack	6963	372	2004	2014
AC856	Gotcha/Great White West	7844		2006	2014
KC964	Hadrian South	7586	182	2009	2014

BOEM Field Name	Nickname	Water Depth	Field Size (MMBoe)	Discovery Year	Start Year of Production
DC048	Dalmatian	5876	89	2008	2015
DC004	Axe	5822	89	2010	2015
GB605	Winter	3400	45	2009	2015
GC432	Samurai	3400	89	2009	2015
GC468	Pony	3497	372	2006	2015
MC771	Kodiak	4986	182	2008	2015
GB427	Cardamom Deep	2720	182	2010	2015
MC762	Deimos South	3122		2010	2015
MC792	West Boreas	3112		2004	2015
GC955	Mission Deep	7300	182	1999	2016
KC102	Tiber	4132	691	2009	2016
KC292	Kaskida	5860	691	2006	2016
MC984	Vito	4038	182	2009	2016
WR508	Stones	9556	89	2005	2016
MC948	Gunflint/Freedom	6095	691	2008	2016
GC859	Heidelberg	5000	182	2009	2016
WR052	Shenandoah	5750	182	2009	2017
KC872	Buckskin	6920	182	2009	2018
LL370	Diamond	9975	45	2008	2018
WR627	Julia	7087	89	2007	2018
KC736	Moccasin	6759		2011	2018
DC353	Vicksburg	7457	372	2007	2019
MC392	Appomattox	7217	691	2009	2019
WR848	Hal	7657	45	2008	2019
DC004	Dalmatian N	5831	89	2010	2020
KC919	Hadrian North	7000	372	2010	2020

* Currently producing

OCS undiscovered technically recoverable resources (mean estimates) – minor changes

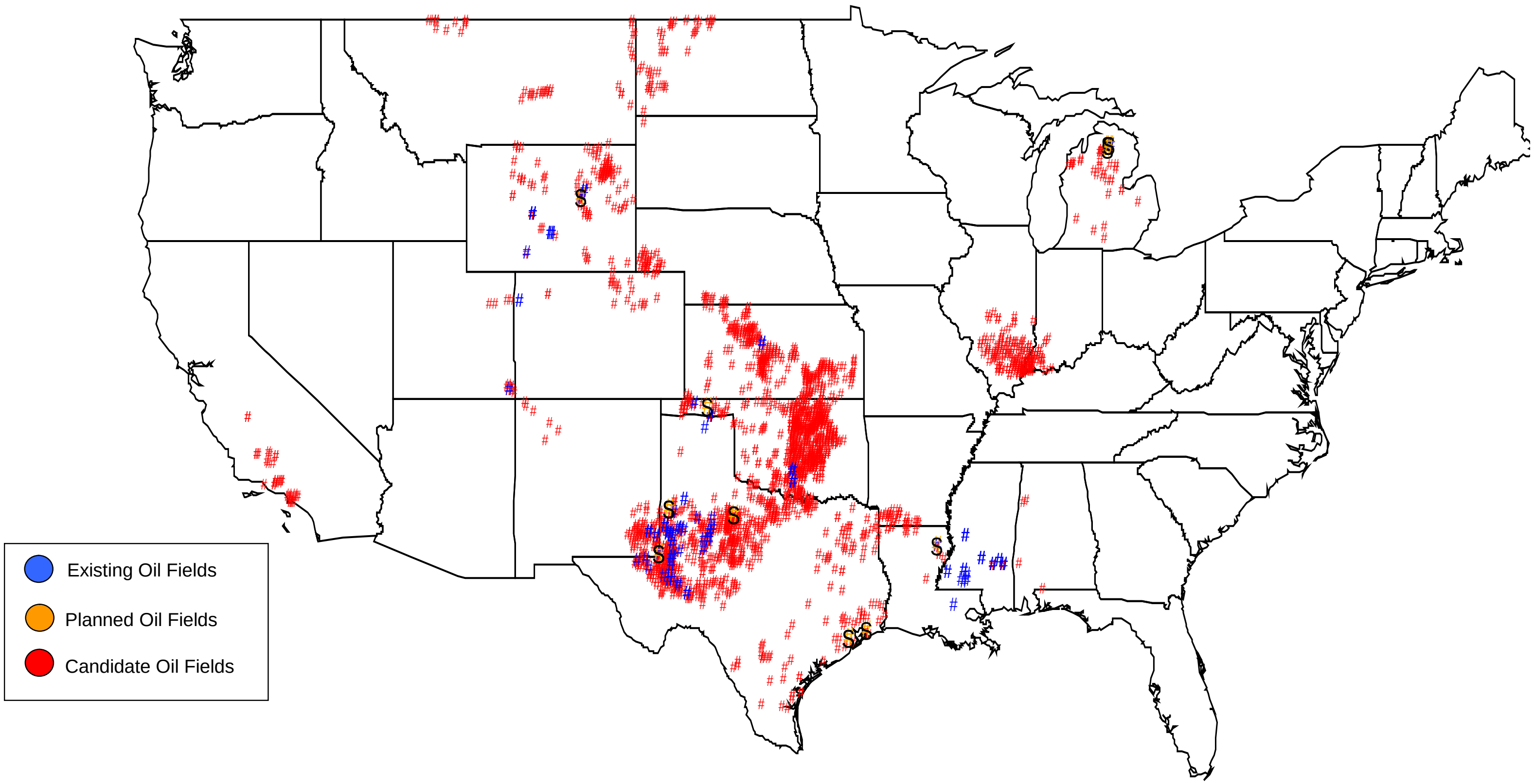
backup

Region	BOEM 2006 Assessment			BOEM 2011 Assessment		
	Oil (Bbo)	Natural Gas (tcf)	BOE (Bbo)	Oil (Bbo)	Natural Gas (tcf)	BOE (Bbo)
Alaska	**26.61**	**132.06**	**50.11**	**26.61**	**131.45**	**50.00**
Atlantic	**3.82**	**36.99**	**10.40**	**3.30**	**31.28**	**8.87**
North	1.91	17.99	5.12	1.35	9.87	3.11
Mid	1.50	15.13	4.19	1.42	19.36	4.87
South	0.41	3.86	1.10	0.53	2.04	0.89
Gulf of Mexico	**44.92**	**232.54**	**86.30**	**48.40**	**219.46**	**87.45**
Western	10.70	66.25	22.49	12.38	69.45	24.74
Eastern	3.88	21.51	7.71	5.07	16.08	7.93
Central	30.32	144.77	56.08	30.93	133.90	54.76
Pacific	**10.53**	**18.29**	**13.79**	**10.20**	**16.10**	**13.07**
WA/OR	0.40	2.28	0.81	0.40	2.28	0.81
Northern CA	2.08	3.58	2.71	2.08	3.58	2.71
Central CA	2.31	2.41	2.74	2.40	2.49	2.84
Southern CA	5.74	10.03	7.52	5.32	7.76	6.70
Total U.S. OCS	85.88	419.88	160.60	88.59	398.37	159.49

CO2 EOR

Potential and current CO_2 EOR projects

Category	Field Count
Active (as of Jan. 1, 2012)	120
Planned (including ROZ)	11
Candidates	2,229



CO_2 availability assumptions

Source Type	Infrastructure Development (years)	Market Acceptance (years)	Ultimate Market Acceptance	Maximum CO_2 Volumes (million tons)	Average Carbon Capture & Transportation (within Region) Cost ($/ton)
Ammonia Plants	2	10	100%	4.5	31
Natural Gas Processing	2	10	100%	10.9	27
Ethanol Plants	4	10	100%	18.4	33
Hydrogen Plants	4	10	100%	0.2	37
Refineries	4	10	100%	16.7	29
Cement Plants	7	10	100%	21.6	70
Fossil Fuel Plants	Determined by the Electricity Market Module (EMM)				
Coal-to-Liquids	Determined by the Liquid Fuels Market Module (LFMM)				

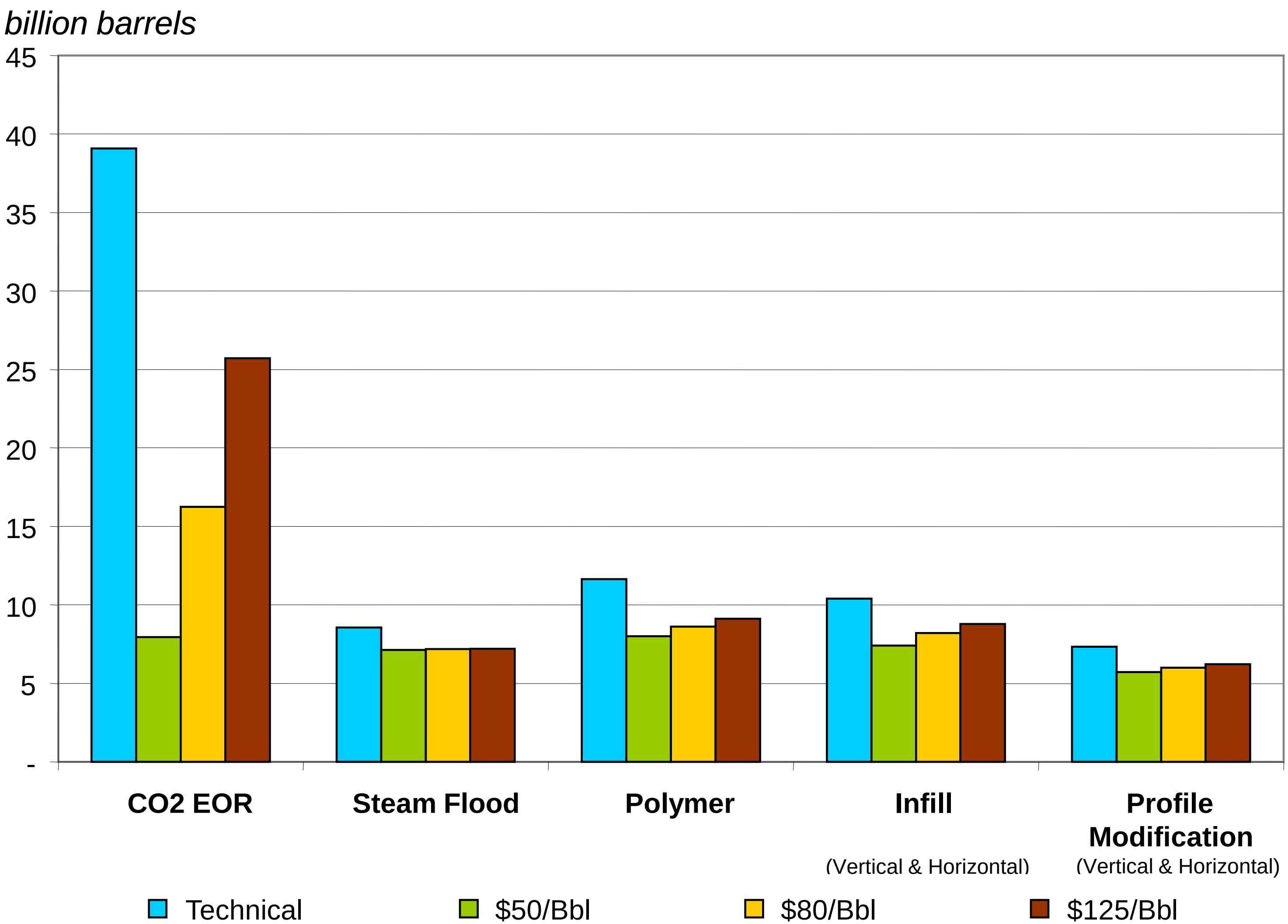
New EMM CO_2 Supply Interface

- EMM determines cost of CO_2 capture and transportation to potential CO_2 EOR fields from new and existing electric power plants.

- OGSM producers see the delivered volume and wellhead cost of CO_2 provided by power plants and determine whether to use that incremental CO_2 supply based on the economics of EOR recovery for their field.

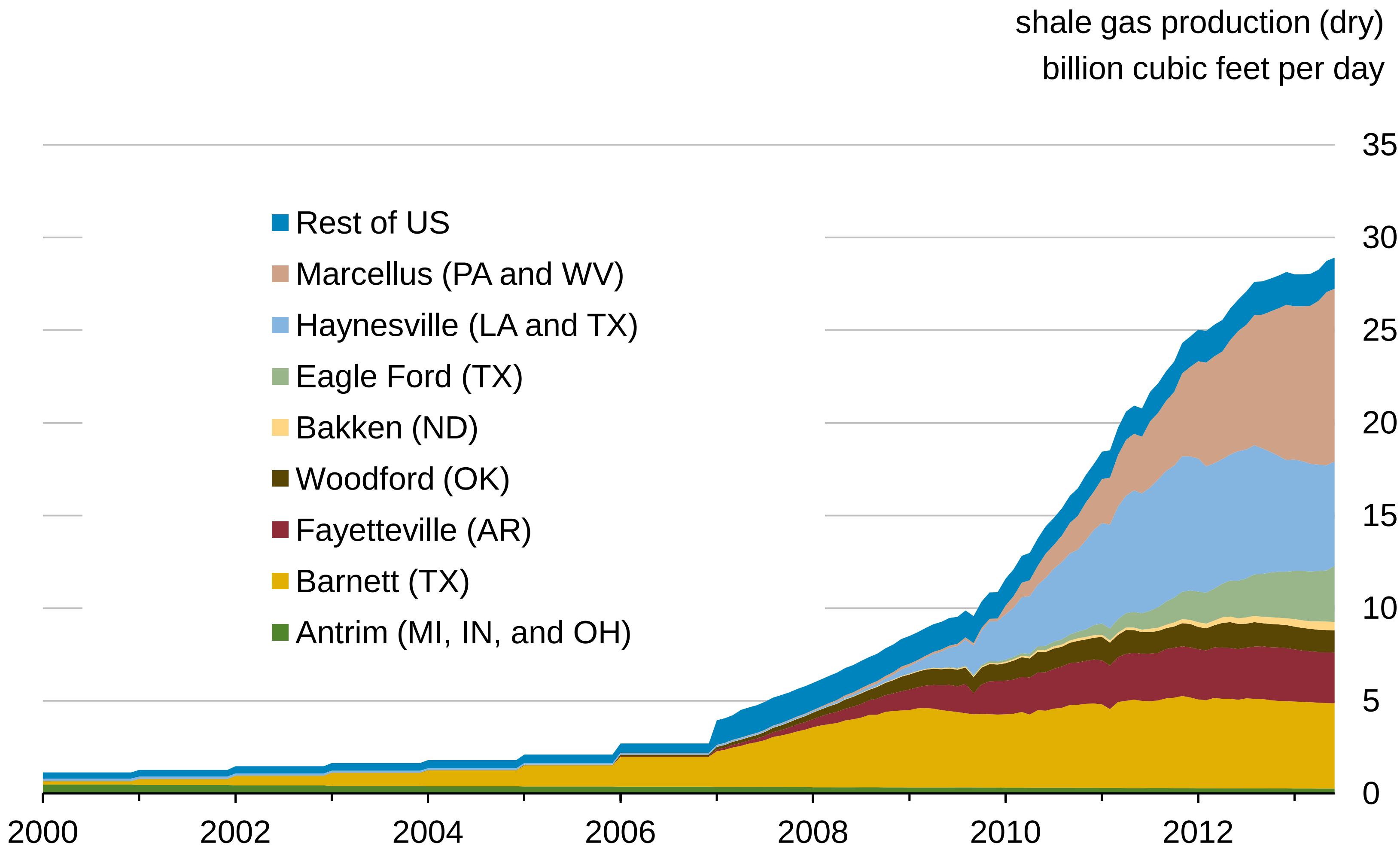
Recoverable EOR/ASR resources

backup



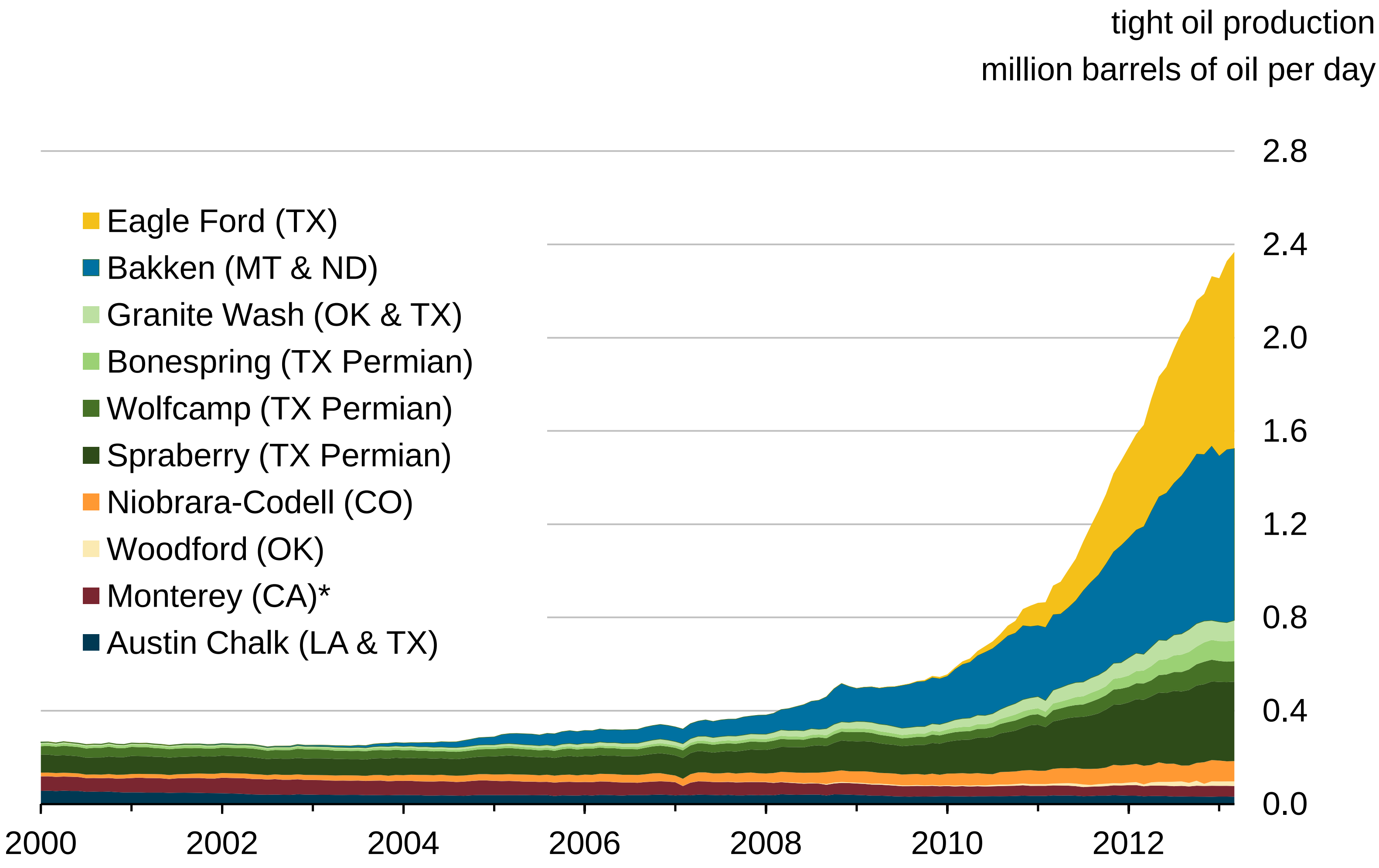
Onshore Lower 48

U.S. dry shale gas production was 28.9 Bcf/d in June 2013. 8% growth over June 2012, 1% growth over May 2013



Sources: LCI Energy Insight gross withdrawal estimates as of June 2013 and converted to dry production estimates with EIA-calculated average gross-to-dry shrinkage factors by state and/or shale play. State abbreviations indicate primary state(s).

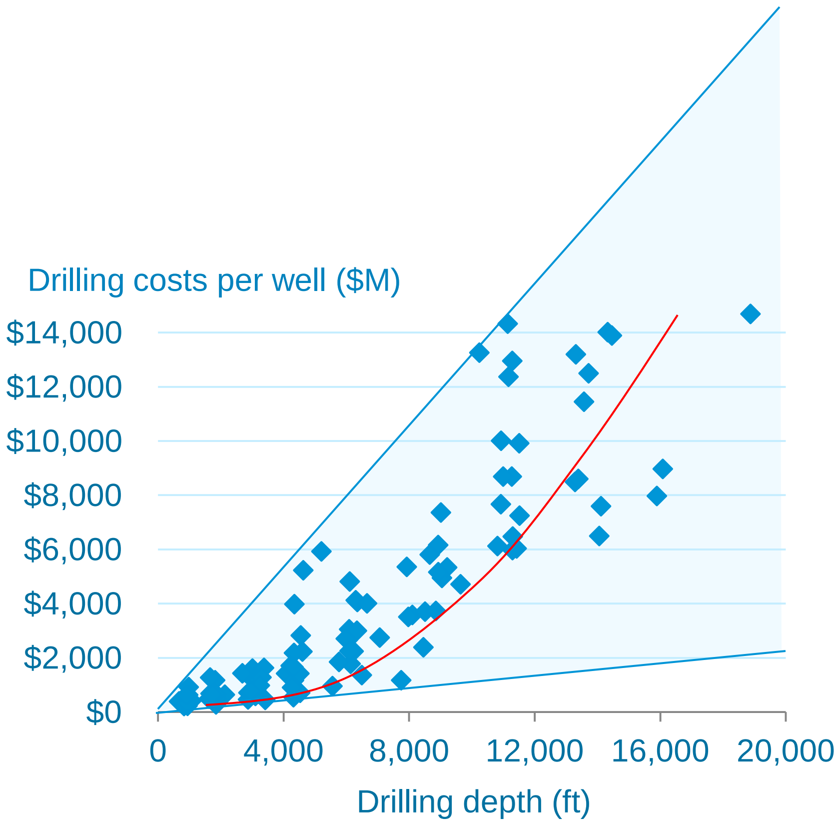
U.S. tight oil production was 2.4 mmbbl/d in March 2013. 46% growth over March 2012, 2% growth over Feb. 2013

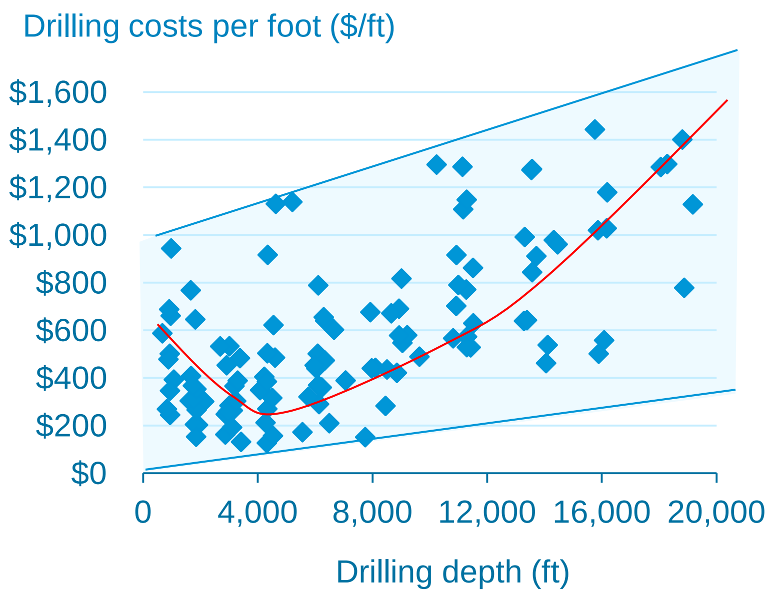


Source: Drilling Info, and EIA, through March 2013. State abbreviations indicate primary state(s).

Drilling cost equations

Wide distribution in drilling costs

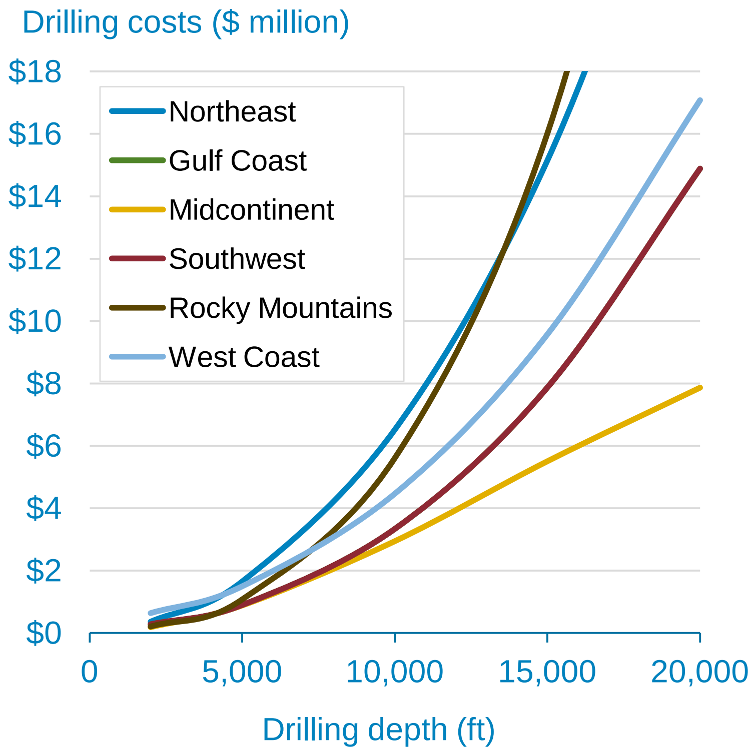


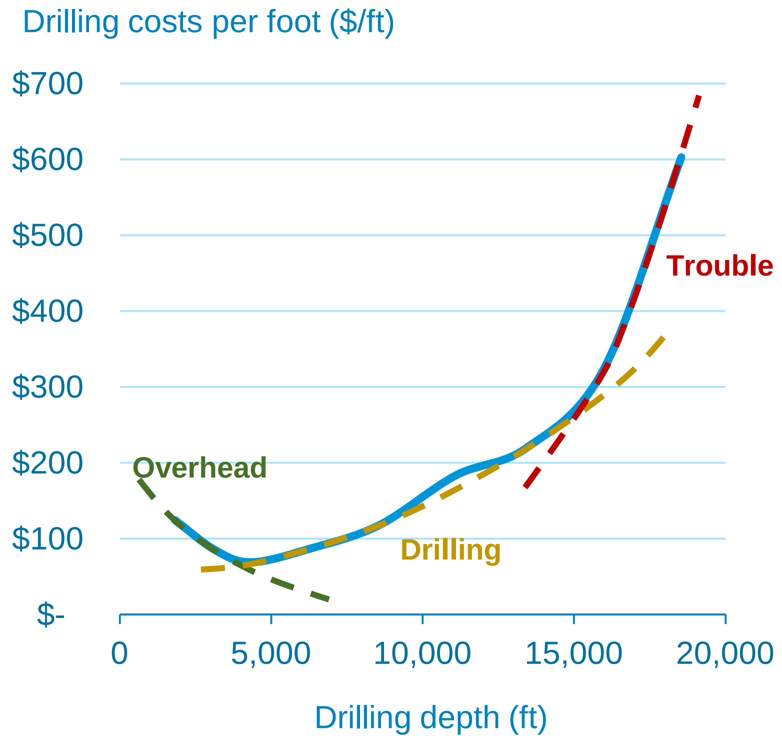


Drilling costs and drilling costs per foot vary more than 100% due to many factors (location, geology, experience, etc.)

Source: JAS 2007

Average drilling costs per foot suggest three dominate cost drivers





Drilling cost equations were revised to represent real-world cost drivers

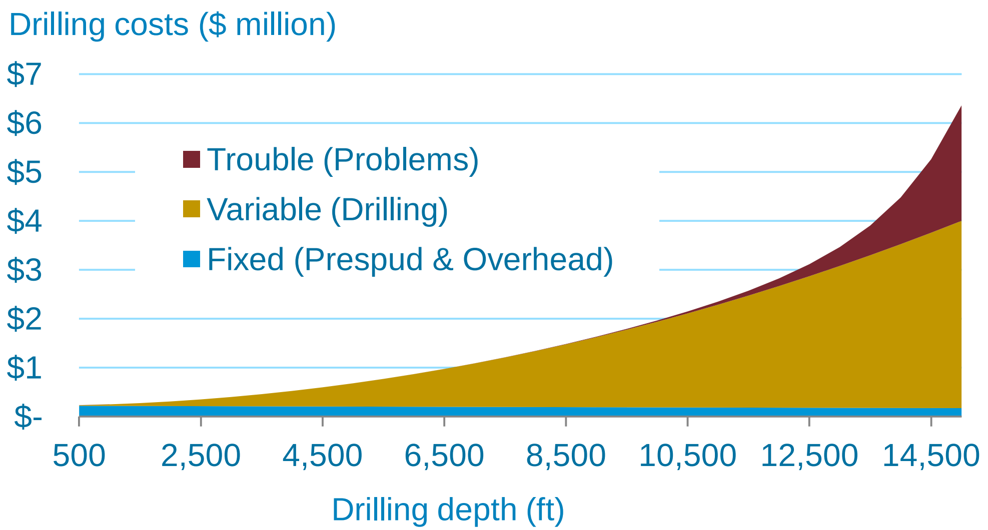
Drilling and completion cost equations

Old Equation : **A** + **B***Depth + **C***Depth^2 + **D***Depth^3 (truncated 3rd Order Polynomial)

New Equation : <u>**A***exp(-**b***Depth)</u> + (**C***Depth + **D***Depth^2) + <u>**E***exp(**f***Depth)</u>

fixed --------------- drilling -------------- trouble

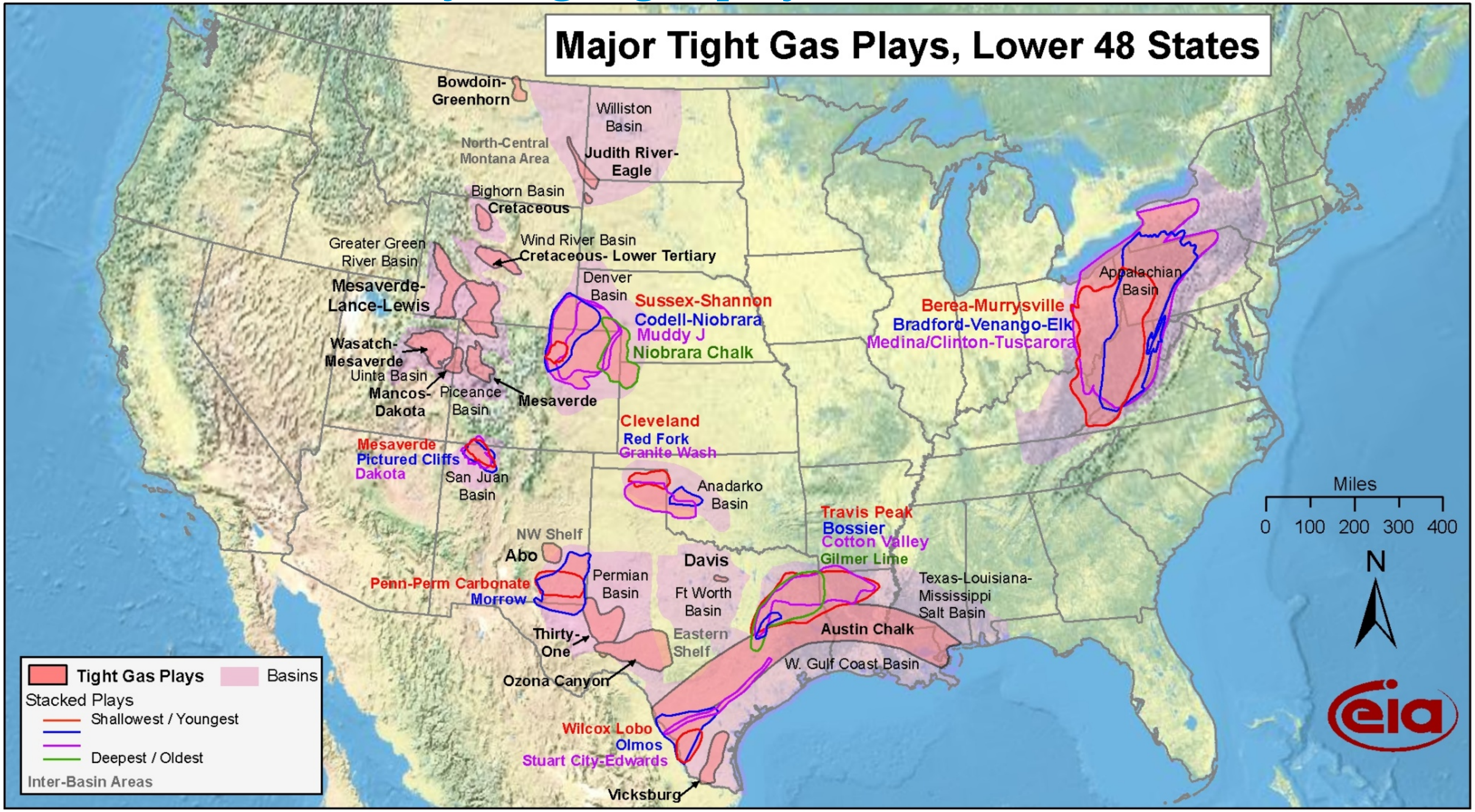
Provides better representation of dominating cost drivers: economy of scale and learning for **fixed costs** (overhead, pre-spud, surface work) and deep well **trouble** (kicks, trips, lower ROPs, rig type switching)



Estimated Ultimate Recovery – continuous plays

Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Lower 48 states major tight gas plays



Source: Energy Information Administration based on data from various published studies
Updated: June 6, 2010

Estimated ultimate recovery (EUR) – continuous plays

- USGS 2012-2013 updates
  - Utica Shale, Appalachian Basin
  - Bakken and Three Forks Formations, Williston Basin
- Play-level EURs are based on historical well performance
  - Individual well performance analyzed (2008-2012)
  - Hyperbolic decline

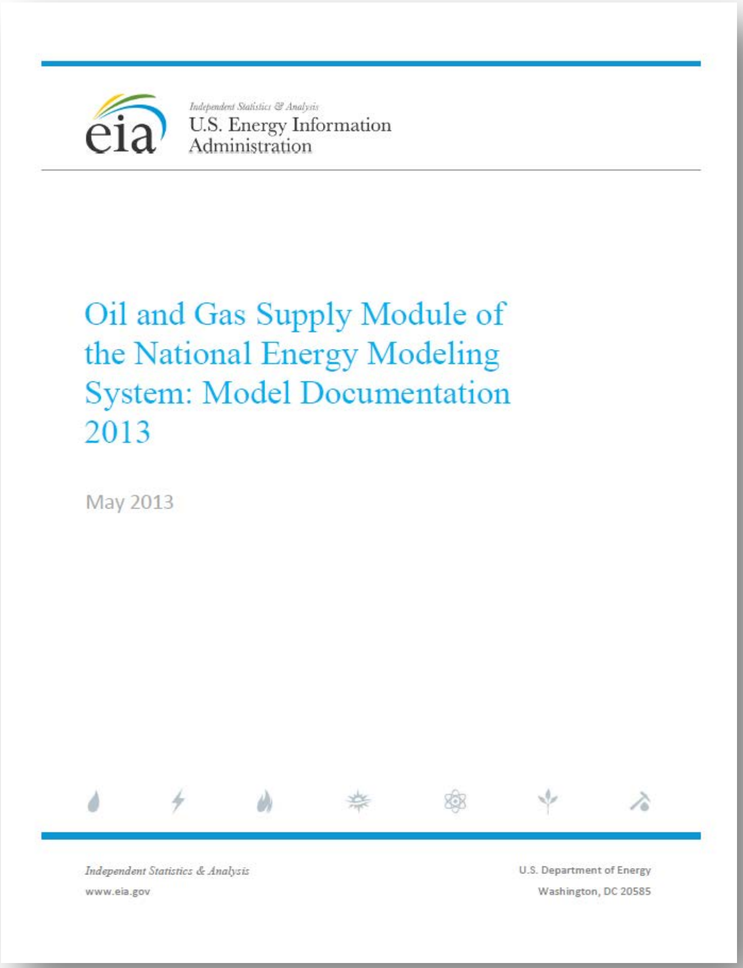
$$Q_t = \frac{Q_i}{\left(1 + b \times D_i \times t\right)^{1/b}}$$

where, $0 < b < 2$ and $0 < D_i < 1$

  - Converts to exponential decline when decline rate reaches Q_{∞}

AEO2013 documentation

http://www.eia.gov/forecasts/nemsdoc/ogsm/pdf/m063(2013).pdf


Independent Statistics & Analysis
U.S. Energy Information Administration

Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2013

May 2013

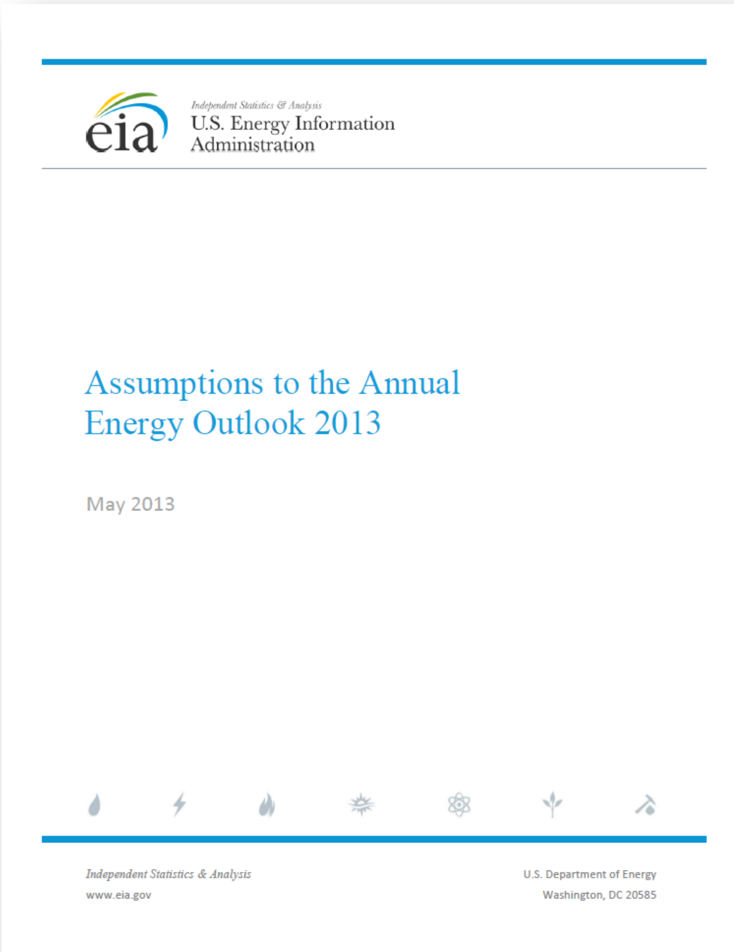
Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

- Pages 182-184 “Appendix 2.C: Decline curve analysis”
- Provides hyperbolic decline curve parameters for selected plays

AEO2013 assumptions

http://www.eia.gov/forecasts/aeo/assumptions/index.cfm


Independent Statistics & Analysis
U.S. Energy Information Administration

Assumptions to the Annual Energy Outlook 2013

May 2013

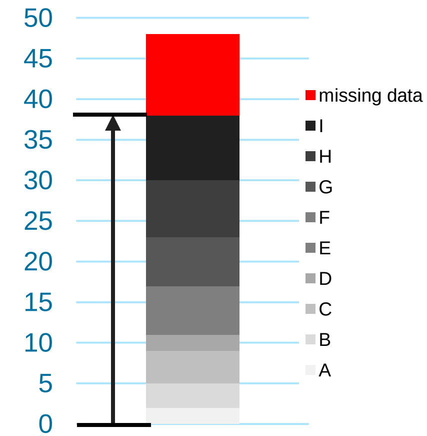
Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

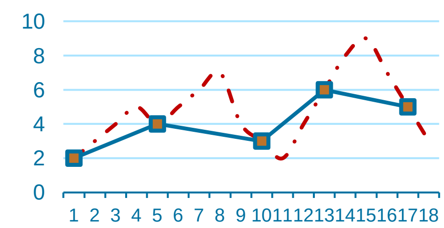
- pages 117-132
- Provides play level
  - well spacing,
  - areas,
  - EUR, and
  - TRR
- CO_2 EOR parameters
- Offshore projects

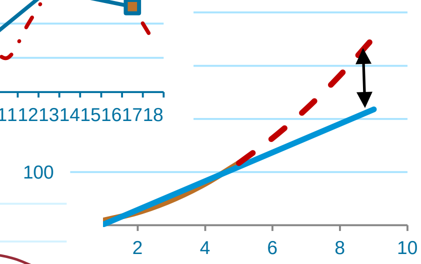
Guarding against conservative biases (blind spots)

- Develop fitting procedures that do not contain “built-in” biases (e.g. working up from zero)

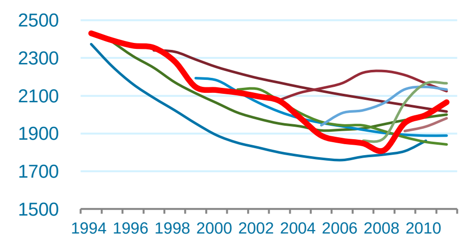


- Limits of interpolation and extrapolation





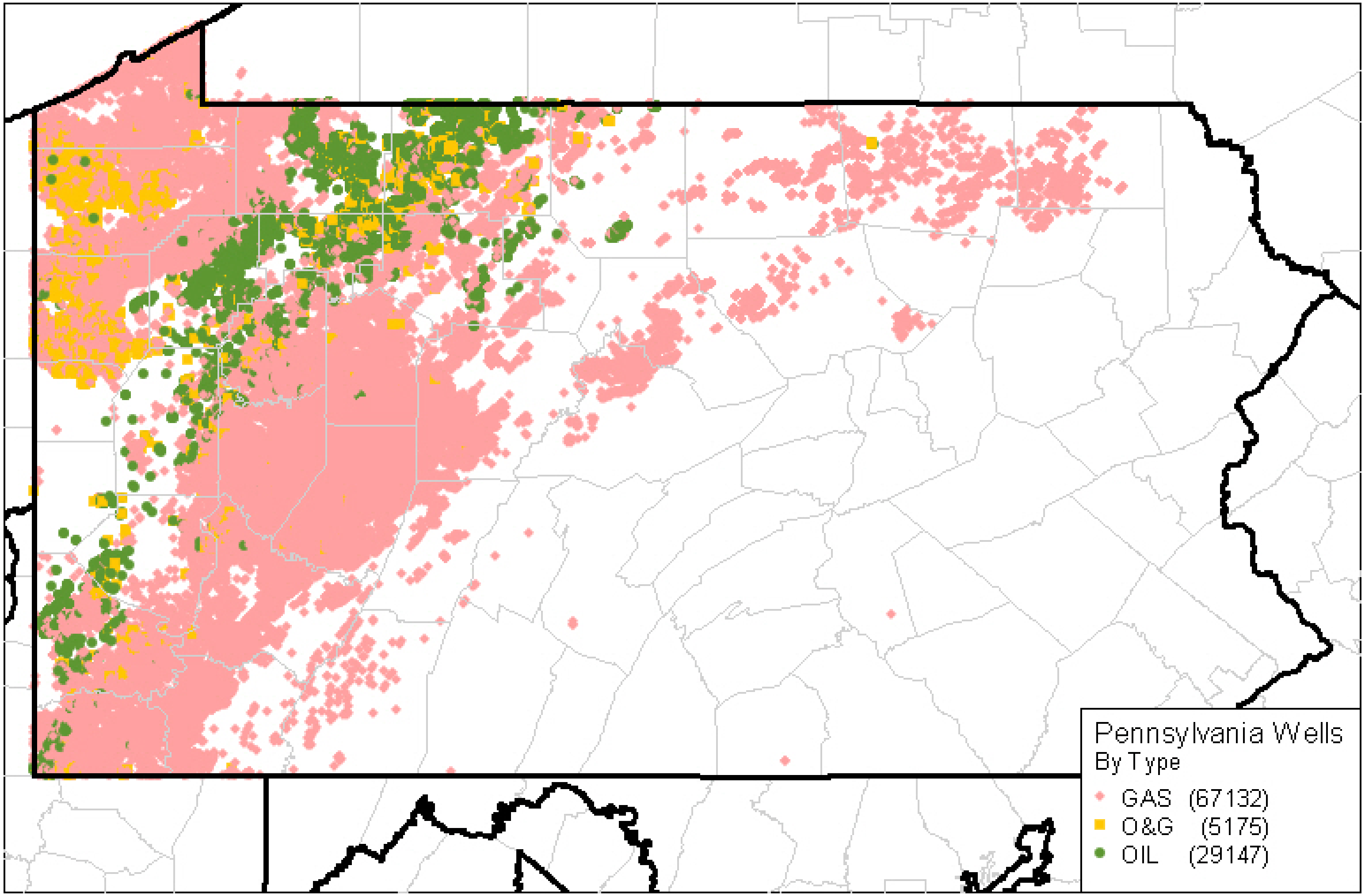
- Historical over and under-estimating



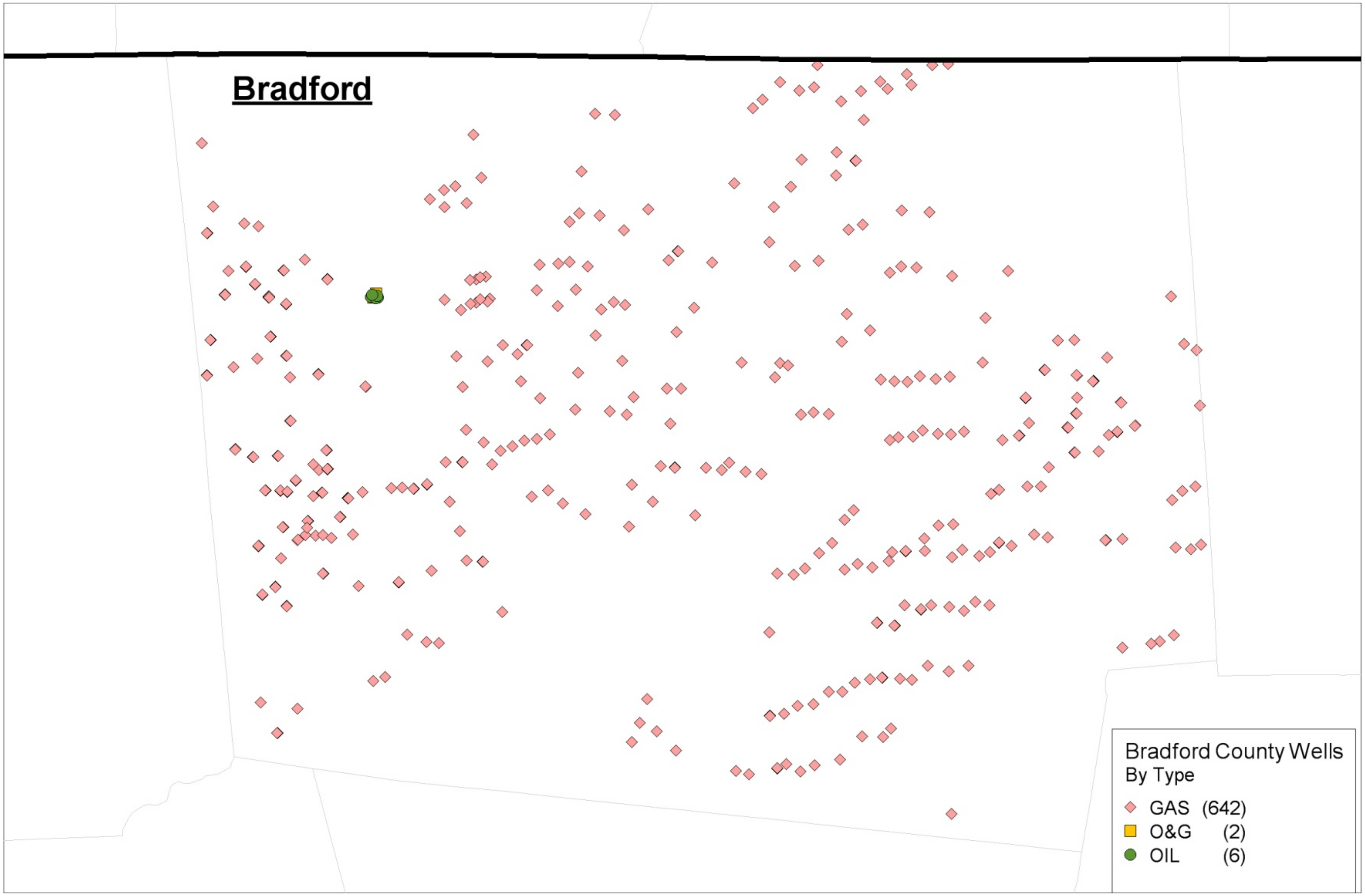
EUR analysis

- County-level review
  - Step 1: Automated fitting routine
  - Step 2: Spot check groups of wells
  - Counties with few to no wells producing?
  - Counties with wide range of EURs?
- Vintage
- Marcellus Example

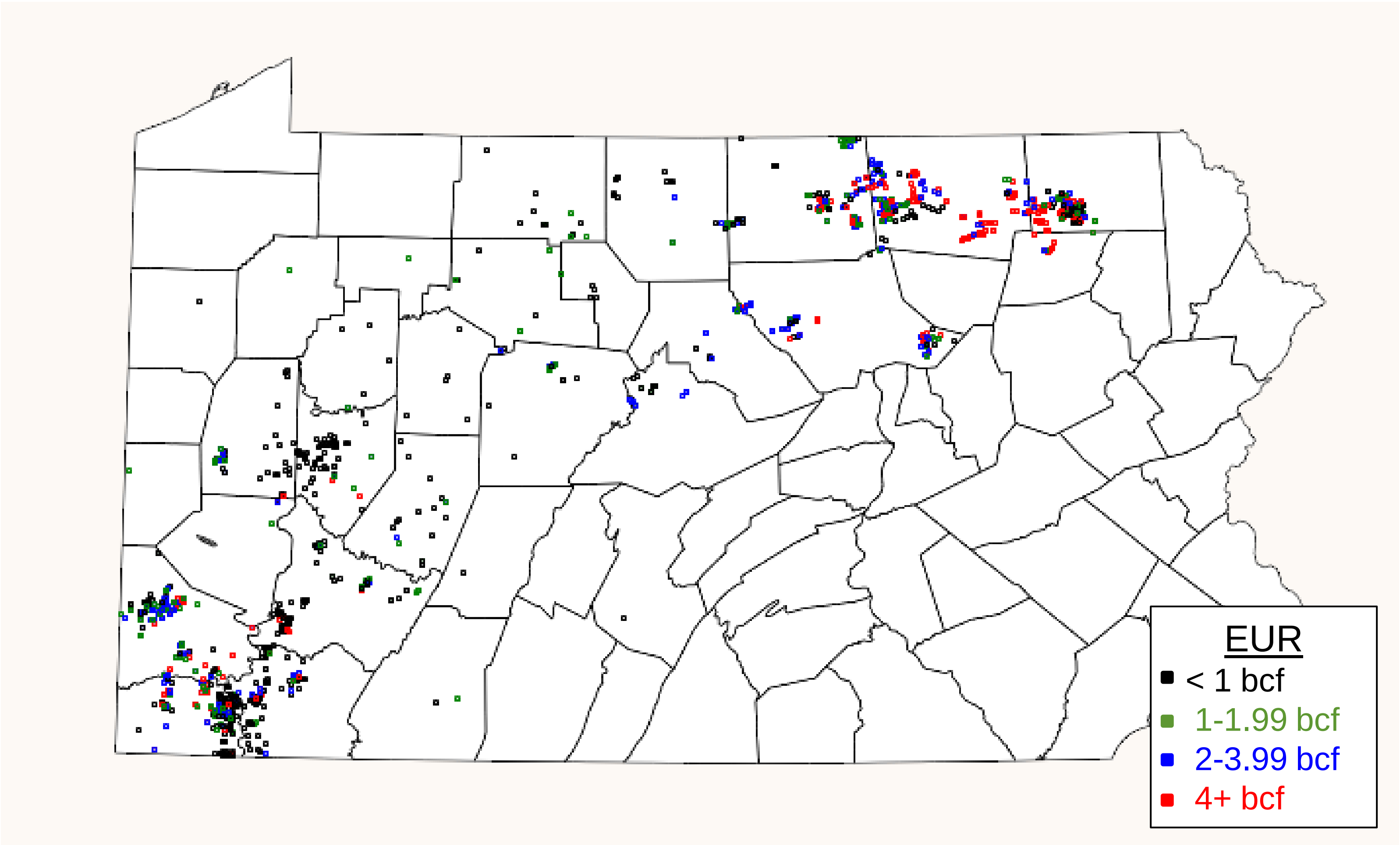
Oil and natural gas drilling in Pennsylvania



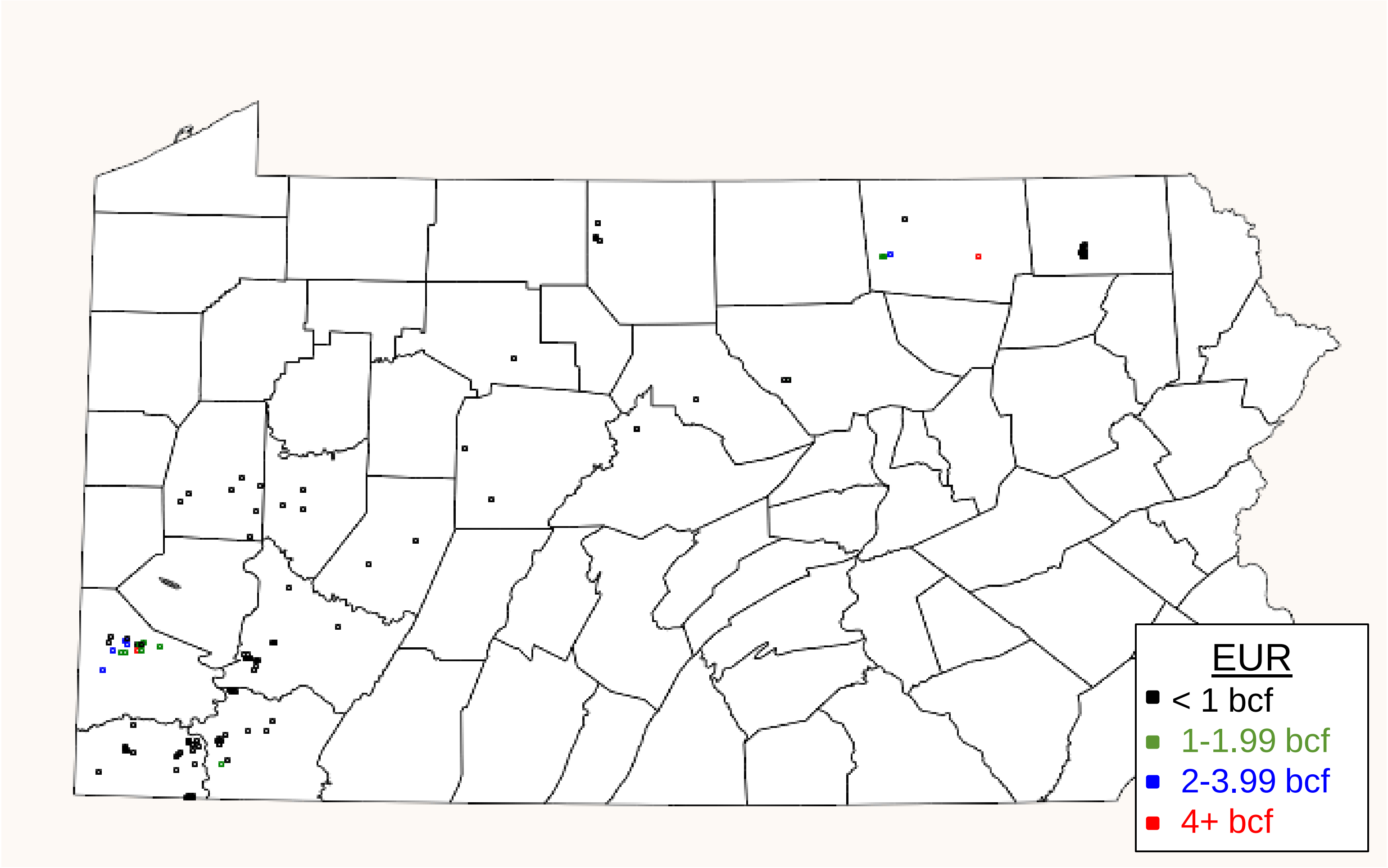
Oil and natural gas drilling in Bradford County, PA



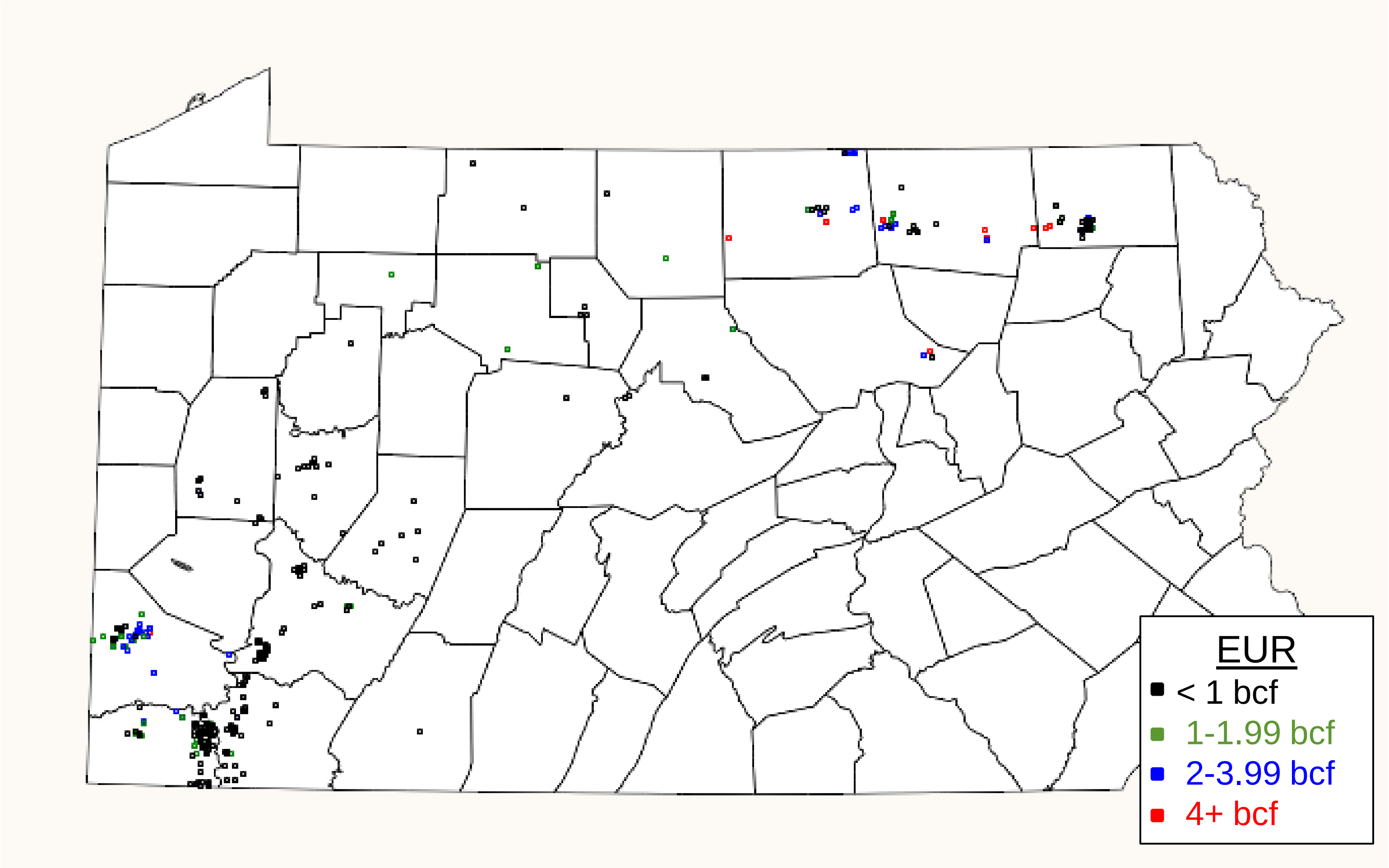
PA Marcellus – 2008-2011 wells (need minimum of 4 data points for EUR fits)



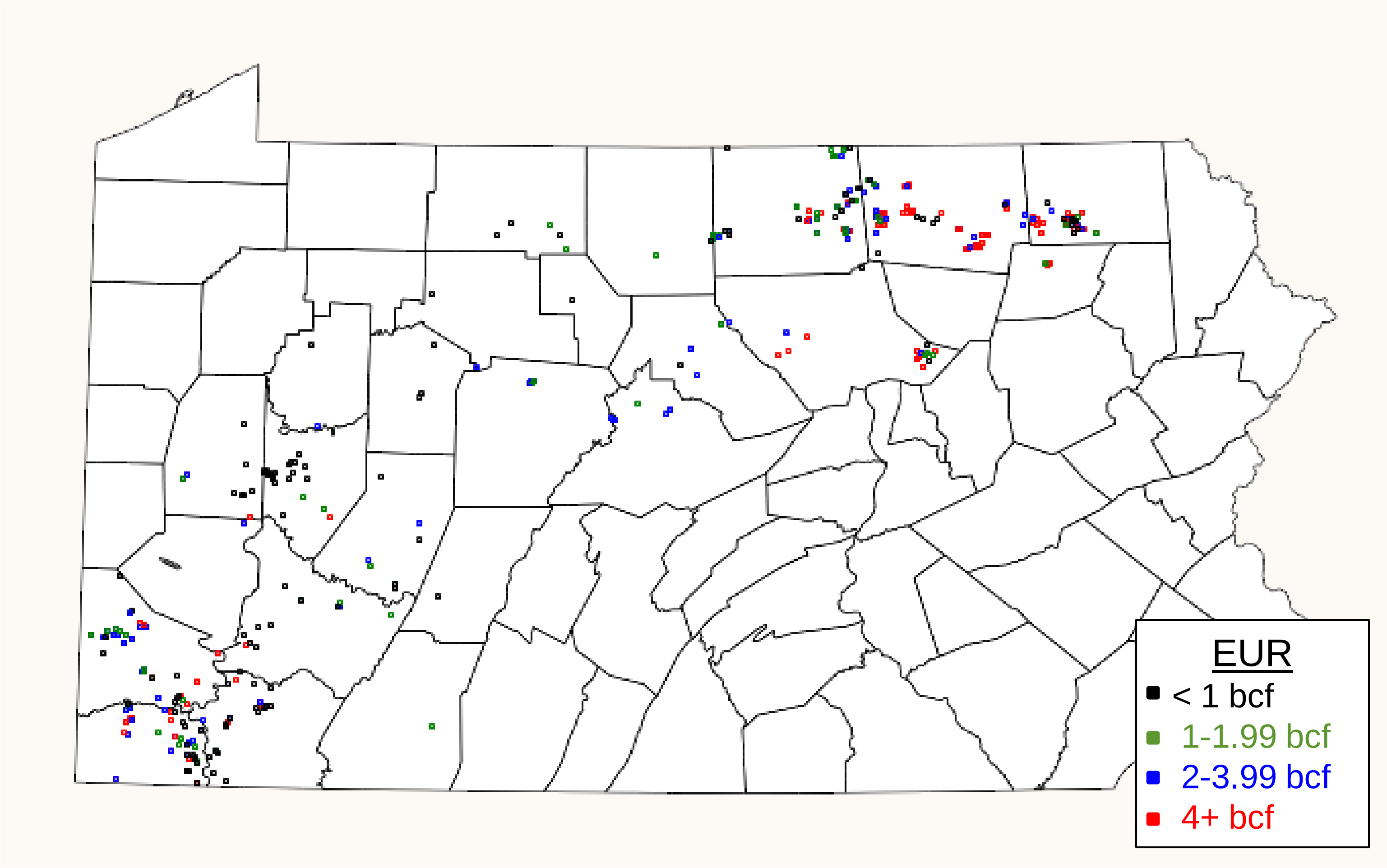
PA Marcellus – 2008 wells



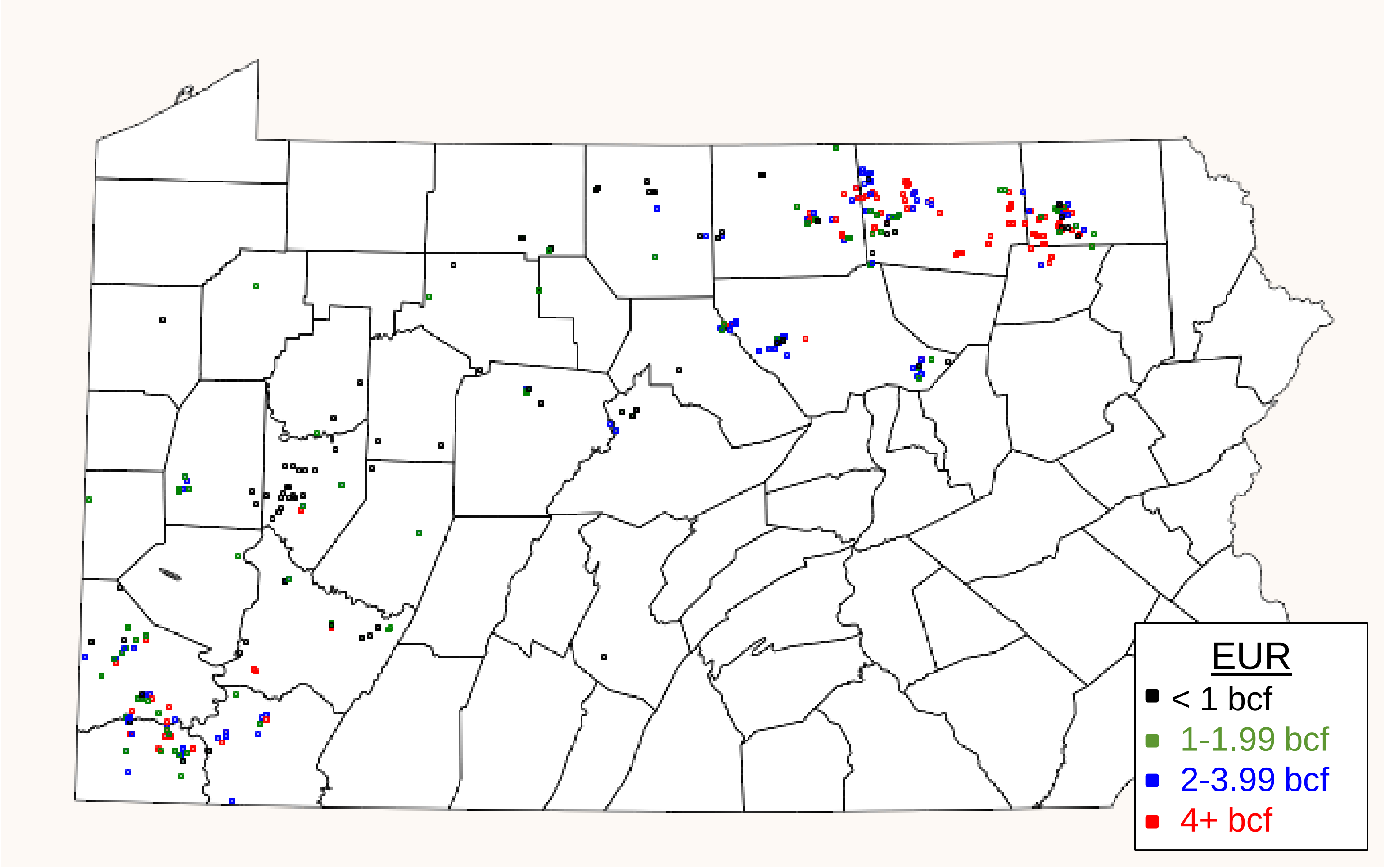
PA Marcellus – 2009 wells



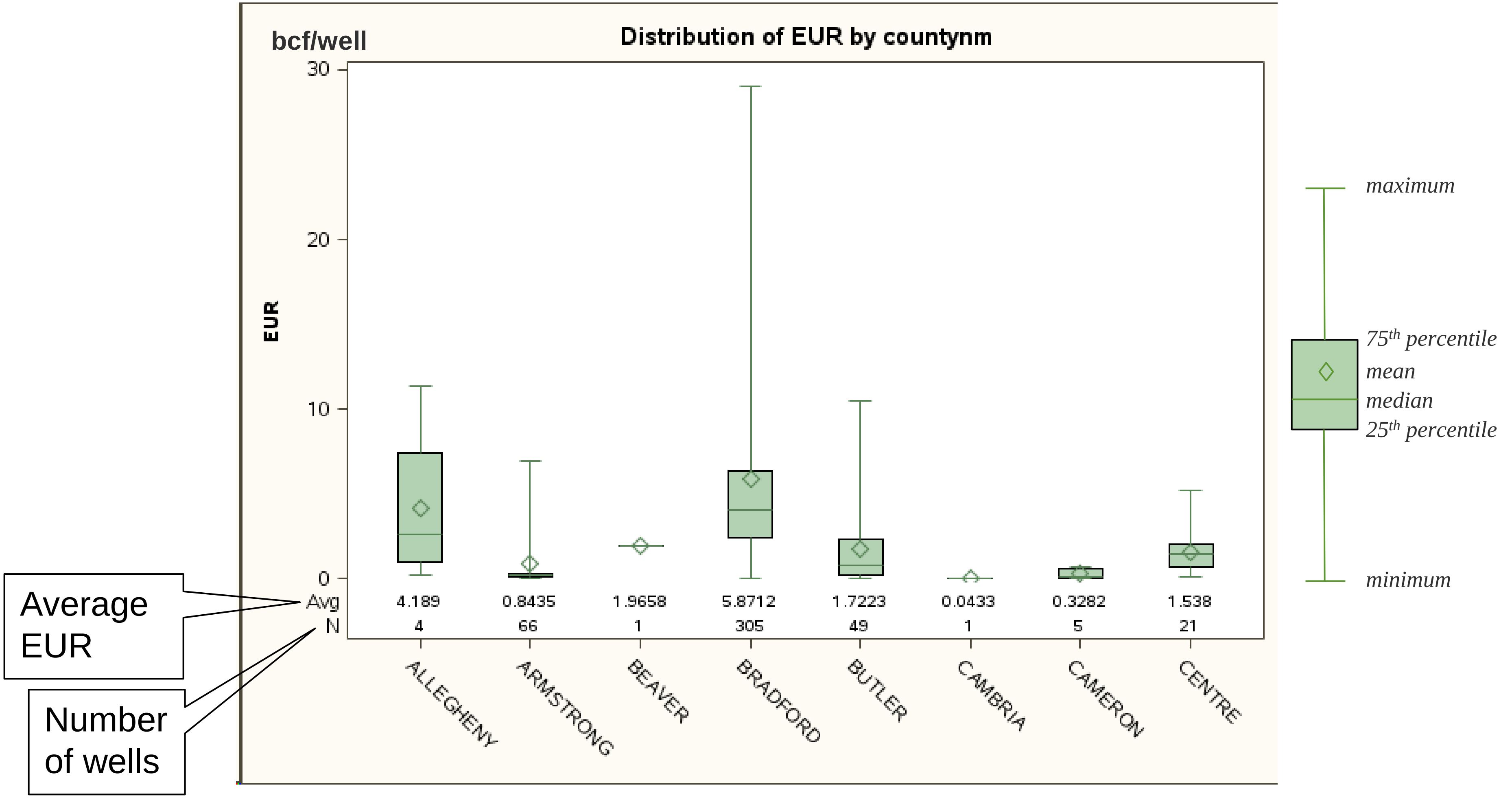
PA Marcellus – 2010 wells



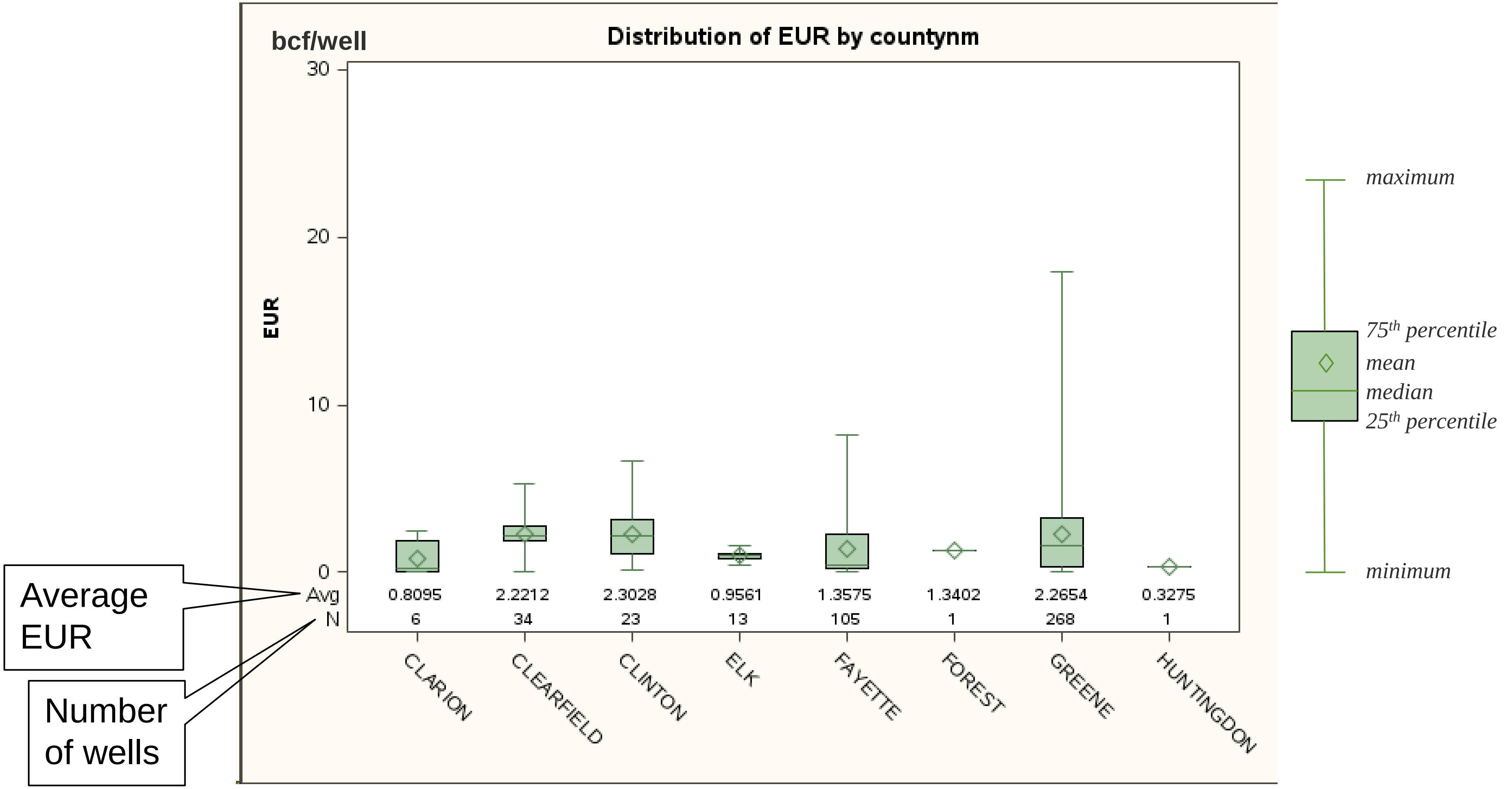
PA Marcellus – 2011 wells



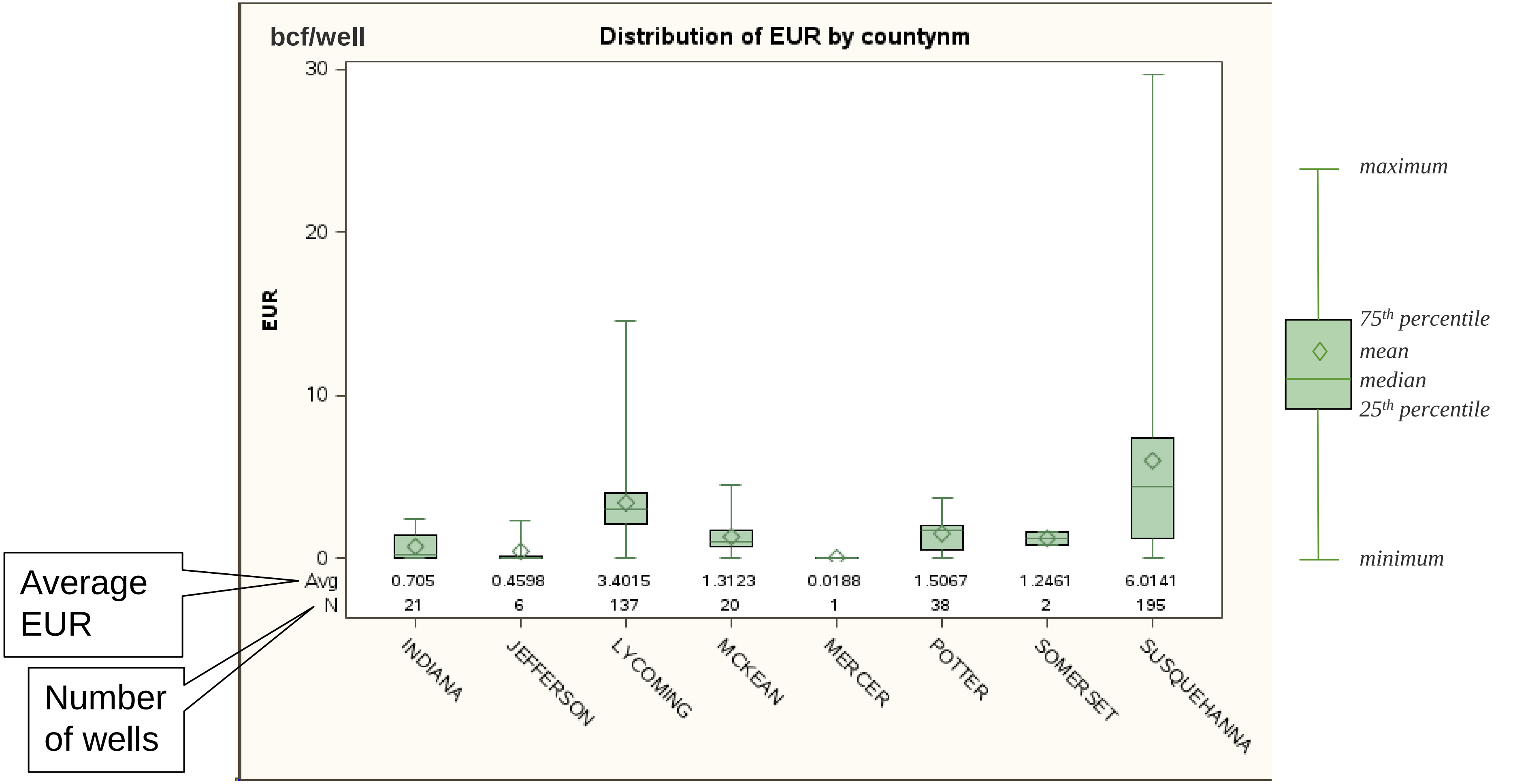
Marcellus Basin – 2008-2011 wells



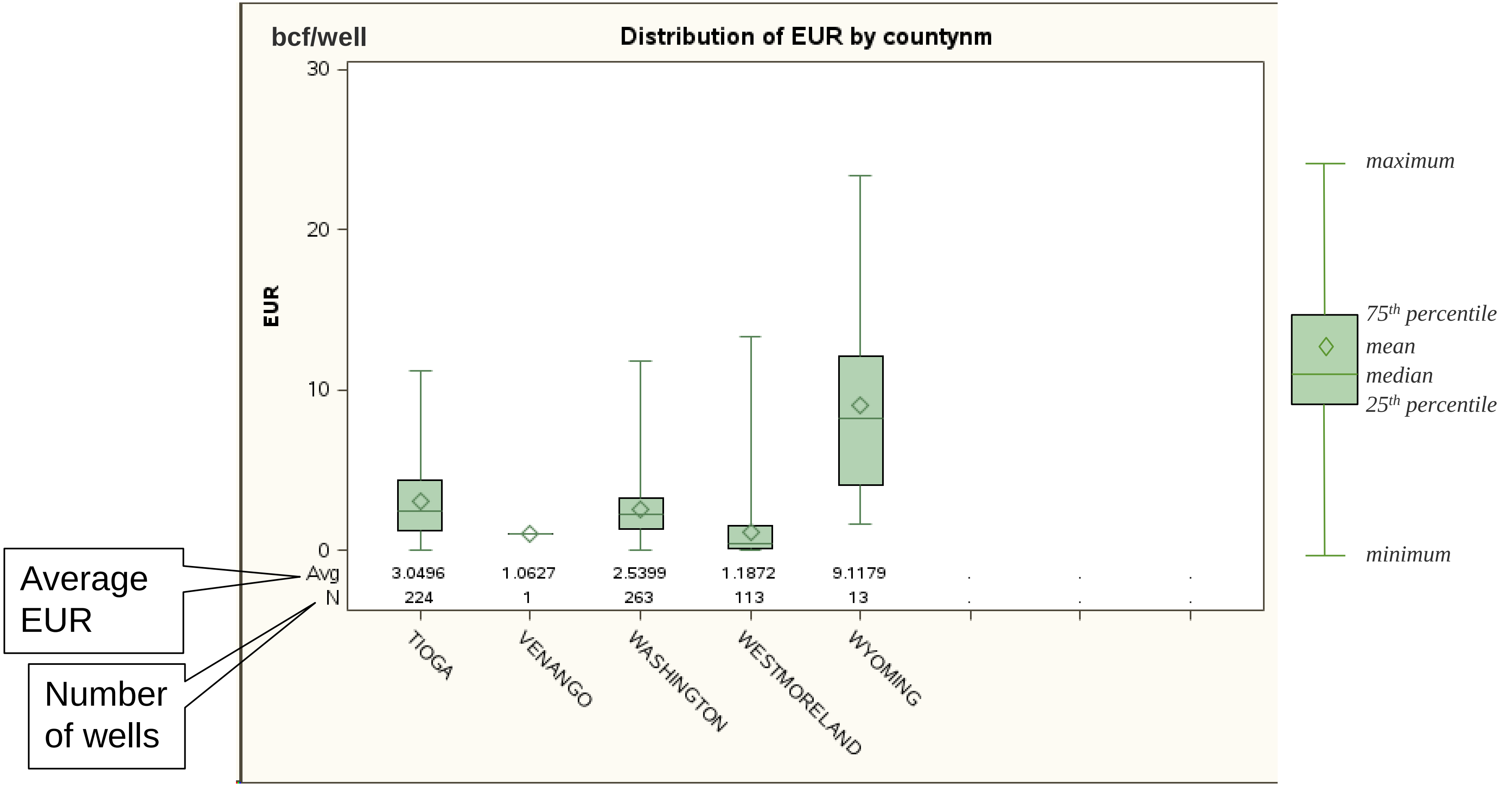
Marcellus Basin – 2008-2011 wells (con't)

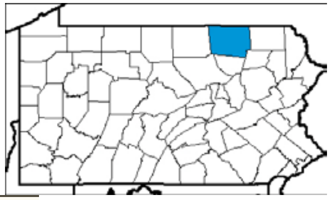


Marcellus Basin – 2008-2011 wells (con't)

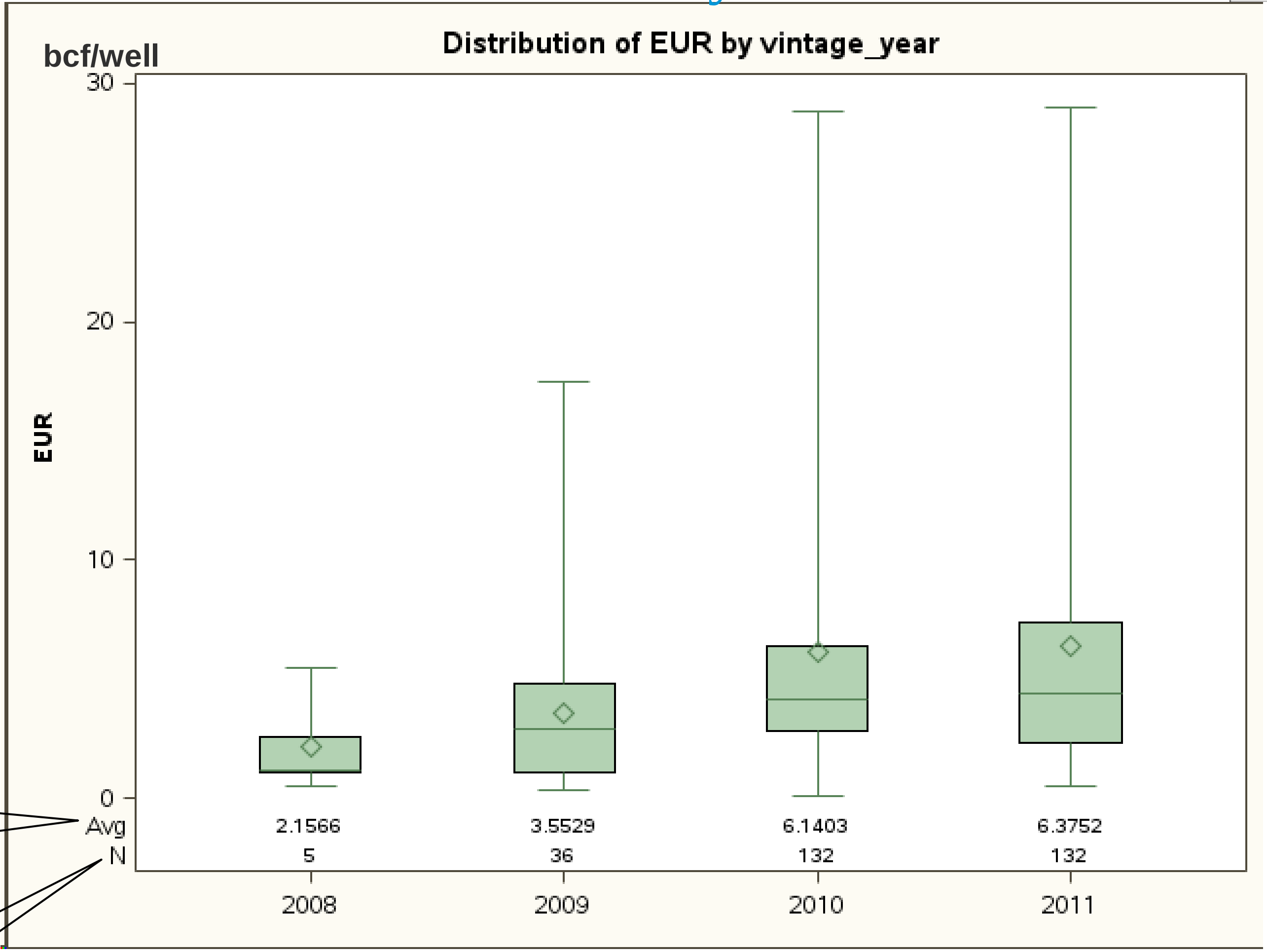


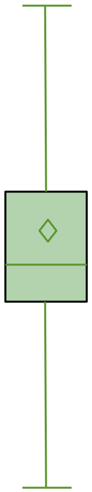
Marcellus Basin – 2008-2011 wells (con't)





Marcellus Basin – Bradford County

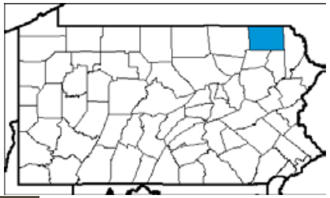


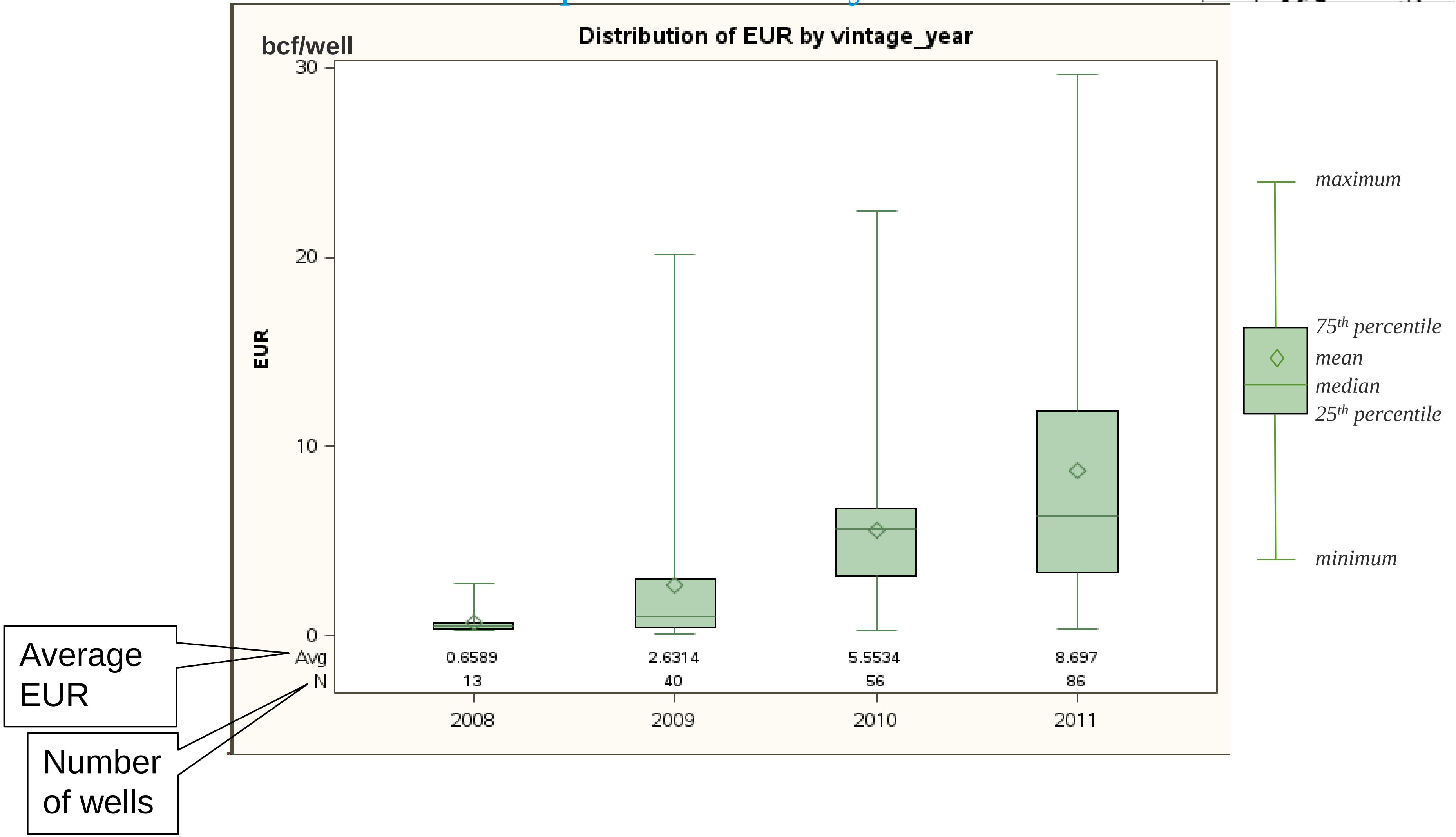


Average EUR

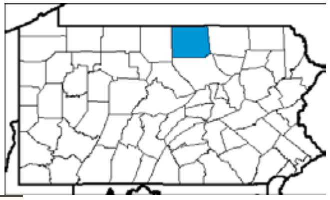
Number of wells

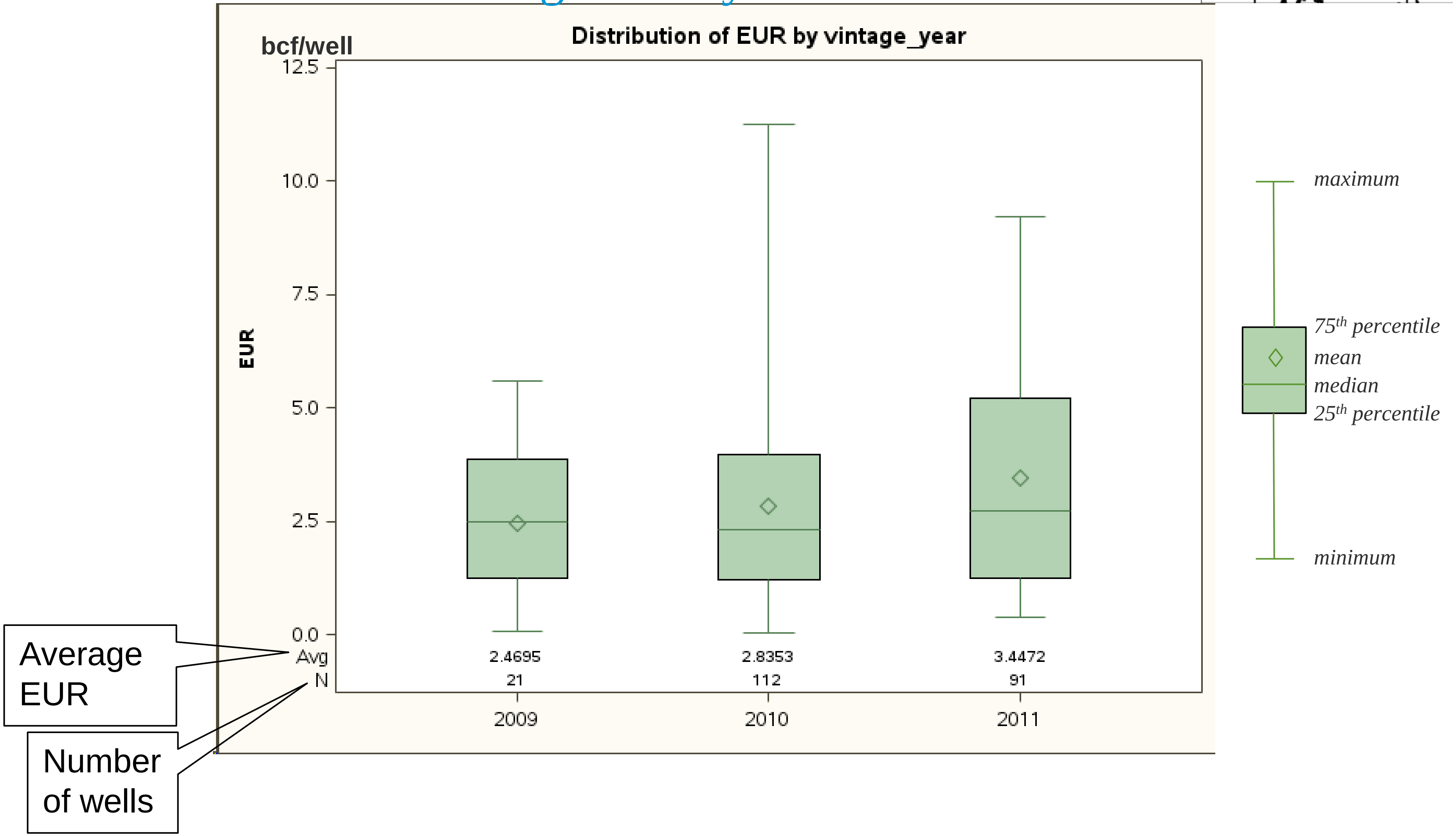
Marcellus Basin – Susquehana County



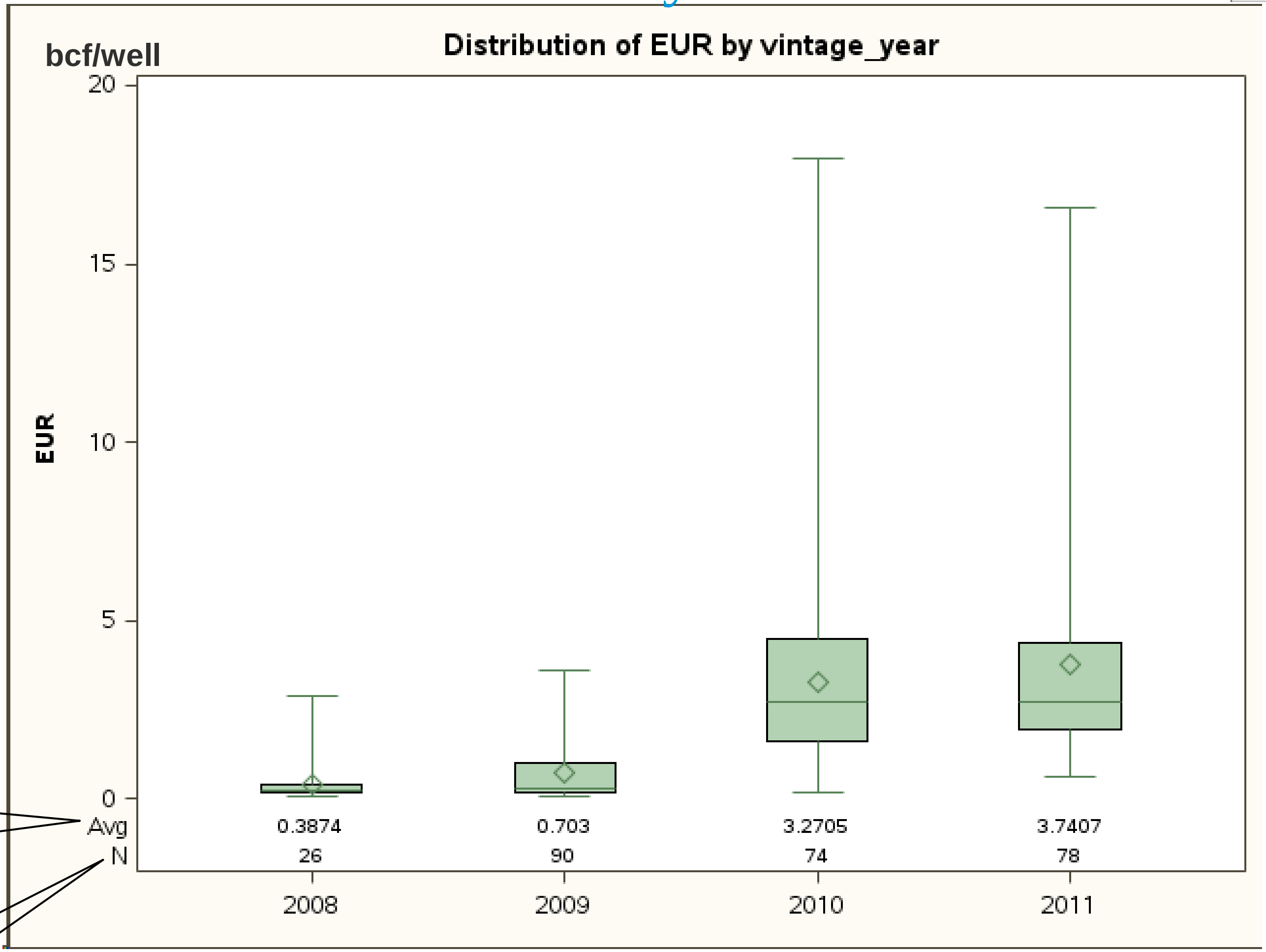


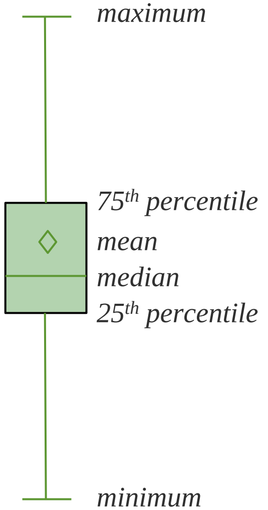
Marcellus Basin – Tioga County

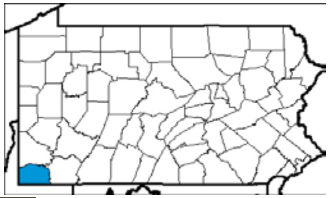




Marcellus Basin – Greene County



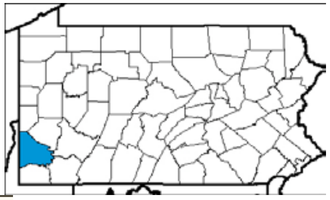


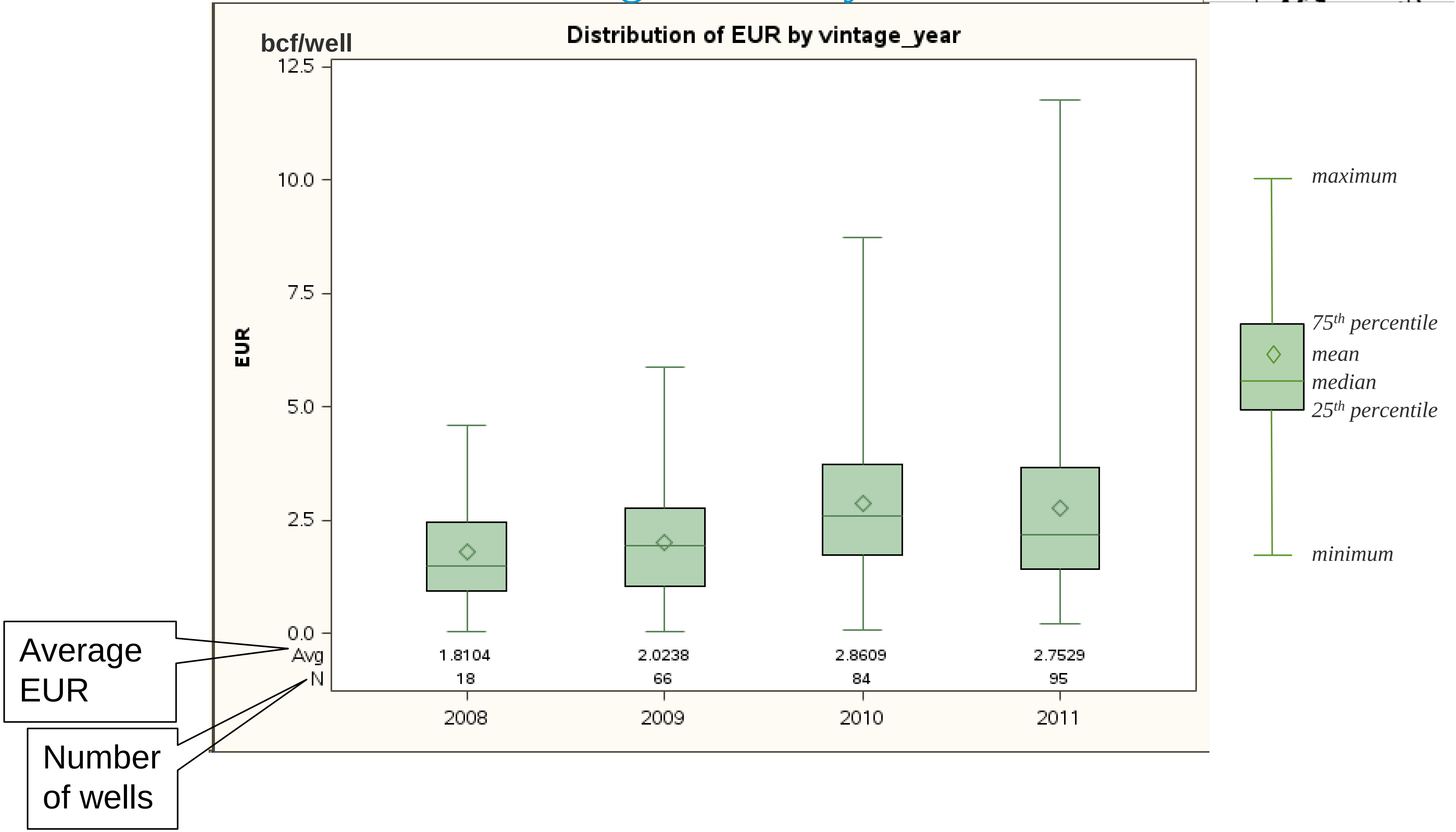


Average EUR

Number of wells

Marcellus Basin – Washington County





Side cases

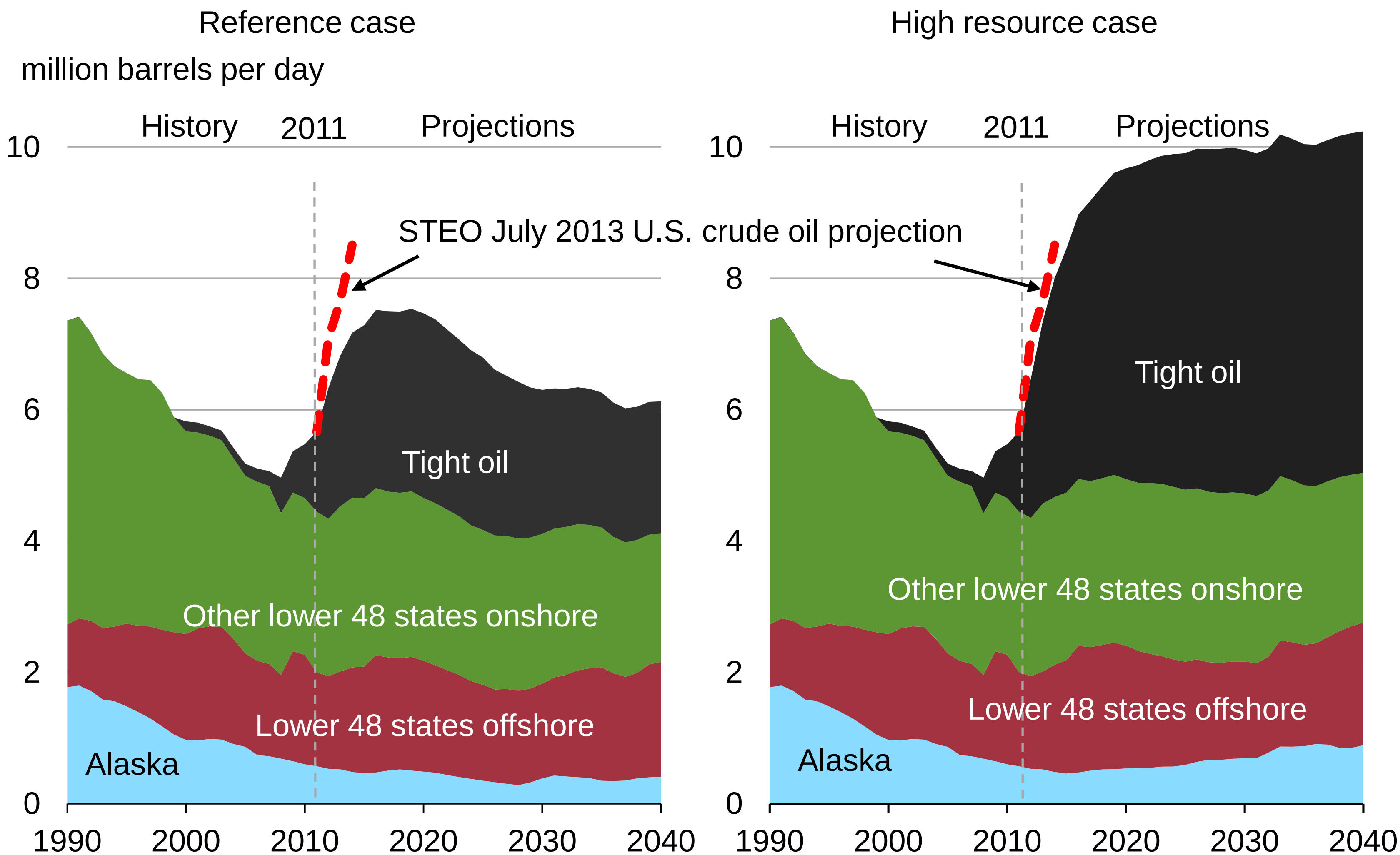
Side cases and Issues and Focus articles

- Planned *AEO2014* Side Cases
  - High/low world oil price
  - High/low macroeconomic growth
  - High/low tight/shale oil and gas resources
- Potential *AEO2014* Side Cases
  - Proposed tax legislation
- *AEO2014* Issues and Focus?

Pending oil and gas tax legislation

- Federal royalty rates
  - Repeal of EPACT 2005 royalty relief
  - Royalty rate changes from 12.5% to 18.75%
- Tax relief
  - Repeal the enhanced oil recovery credit
  - Repeal the credit for oil and natural gas produced from marginal wells
  - Repeal the deduction for tertiary injectants
  - Repeal expensing of IDCs
  - Repeal percentage depletion for oil and natural gas wells

U.S. tight oil production leads growth in domestic production



Source: EIA, Annual Energy Outlook 2013 and Short-Term Energy Outlook, July 2013 end of year values.

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General oil and gas questions | john.staub@eia.gov

For more information

U.S. Energy Information Administration home page | www.eia.gov

Short-Term Energy Outlook | www.eia.gov/steo

Annual Energy Outlook | www.eia.gov/aeo

International Energy Outlook | www.eia.gov/ieo

Monthly Energy Review | www.eia.gov/mer

Today in Energy | www.eia.gov/todayinenergy