Applying Probabilistic Well-Performance Parameters to Assessments of Shale-Gas Resources*

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Abstract

In assessing continuous oil and gas resources, such as shale gas, it is important to describe not only the ultimately producible volumes, but also the expected well performance. This description is critical to any cost analysis or production scheduling. A probabilistic approach facilitates (1) the inclusion of variability in well performance within a continuous accumulation, and (2) the use of data from developed accumulations as analogs for the assessment of undeveloped accumulations.

In assessing continuous oil and gas resources of the United States, the U.S. Geological Survey analyzed production data from many shale-gas accumulations. Analyses of four of these accumulations (the Barnett, Woodford, Fayetteville, and Haynesville shales) are presented here as examples of the variability of well performance. For example, the distribution of initial monthly production rates for Barnett vertical wells shows a noticeable change with time, first increasing because of improved completion practices, then decreasing from a combination of decreased reservoir pressure (in infill wells) and drilling in less productive areas.

Within a partially developed accumulation, historical production data from that accumulation can be used to estimate production characteristics of undrilled areas. An understanding of the probabilistic relations between variables, such as between initial production and decline rates, can improve estimates of ultimate production. Time trends or spatial trends in production data can be clarified by plots and maps. The data can also be divided into subsets depending on well-drilling or well-completion techniques, such as vertical in relation to horizontal wells.

For hypothetical or lightly developed accumulations, one can either make comparisons to a specific well-developed accumulation or to the entire range of available developed accumulations. Comparison of the distributions of initial monthly production rates of the four shale-gas accumulations that were studied shows substantial overlap. However, because of differences in decline rates among them, the resulting estimated ultimate recovery (EUR) distributions are considerably different.

Reference

Cook, Troy, and R.R. Charpentier, 2010, Assembling probabilistic performance parameters of shale-gas wells: U.S. Geological Survey Open-File Report 2010-1138, 17 p.

Applying Probabilistic Well-Performance Parameters to Assessments of Shale-Gas Resources

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U.S. Geological Survey

USGS

USGS Assessments Before 1995

- In-place estimate plus estimate of recovery factor
- Volumetric calculations of rock volumes and resource densities
  - In pore space
  - Sorbed
- Recovery factors poorly known

USGS

USGS Assessments 1995 to Present

- Well production data used to derive a distribution of estimated ultimate recoveries (EURs)
  - Divide assessed area into cells
  - Calculate numbers of untested cells
  - Apply EURs to cells

USGS

Methodology Needs

- Digest larger volumes of production data
- Better include geologic understanding of spatial and temporal trends
- Apply analog information to hypothetical or very immature assessment units

USGS

Present Calculation Method

- Present USGS method calculates as if you were sampling from the EUR distribution thousands of times independently
  - Calculates as if mean EUR were known exactly
  - Underestimates uncertainty

USGS

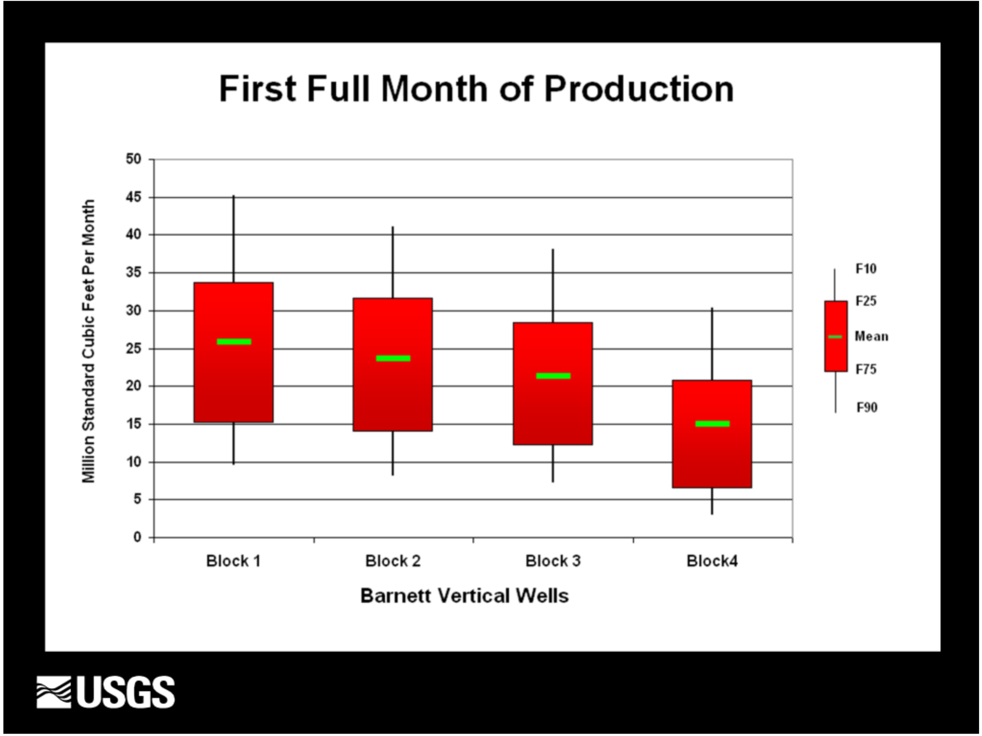
Improved USGS Methodology

- Directly estimates uncertainty of EUR
  - Affected by temporal and spatial trends
  - Depends on geology, not just data
- Based on wells, not cells
- Assesses sweet spots and nonsweet spots

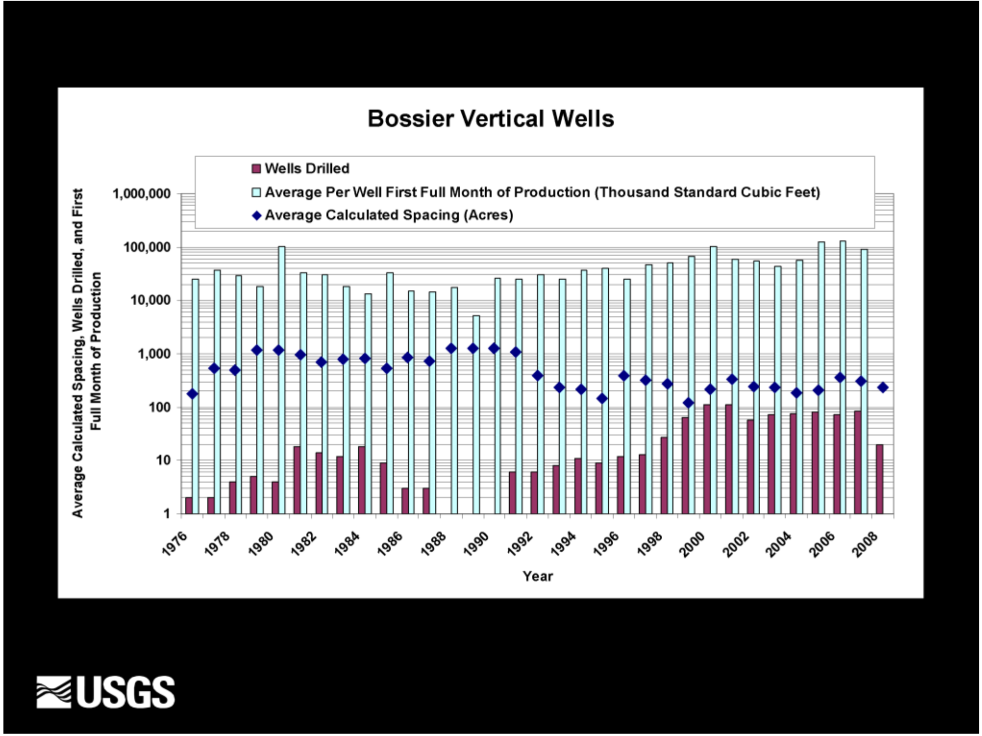
Temporal Trends

- Historical success ratios and EUR distributions may not be appropriate for future drilling
- Look at temporal changes in EUR distribution
  - Changes in technological practice
  - Changes related to geology

USGS



This diagram shows distribution of production for four groups of vertical Barnett Shale wells of roughly equal size, with group 1 containing the earliest wells and group 4 the most recent. The data show a decrease in first full month well production over time.



This figure compares trends in Bossier Formation well characteristics over time. Around 1990, there was an increase in drilling accompanied by a decrease in average well spacing and an increase in average first full month production. Data for 2008 are incomplete.

Spatial Trends

- Look at spatial changes in EUR distribution
  - Define sweet spots
- Compare to known geology
  - Thickness
  - Total organic carbon (TOC)
  - Thermal maturity

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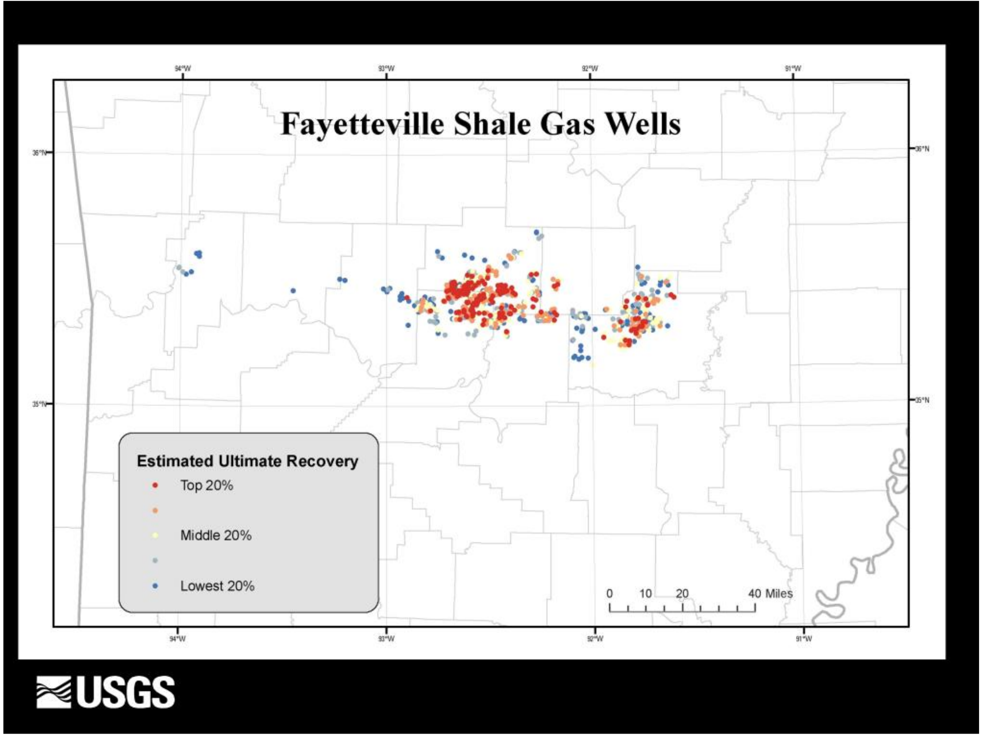
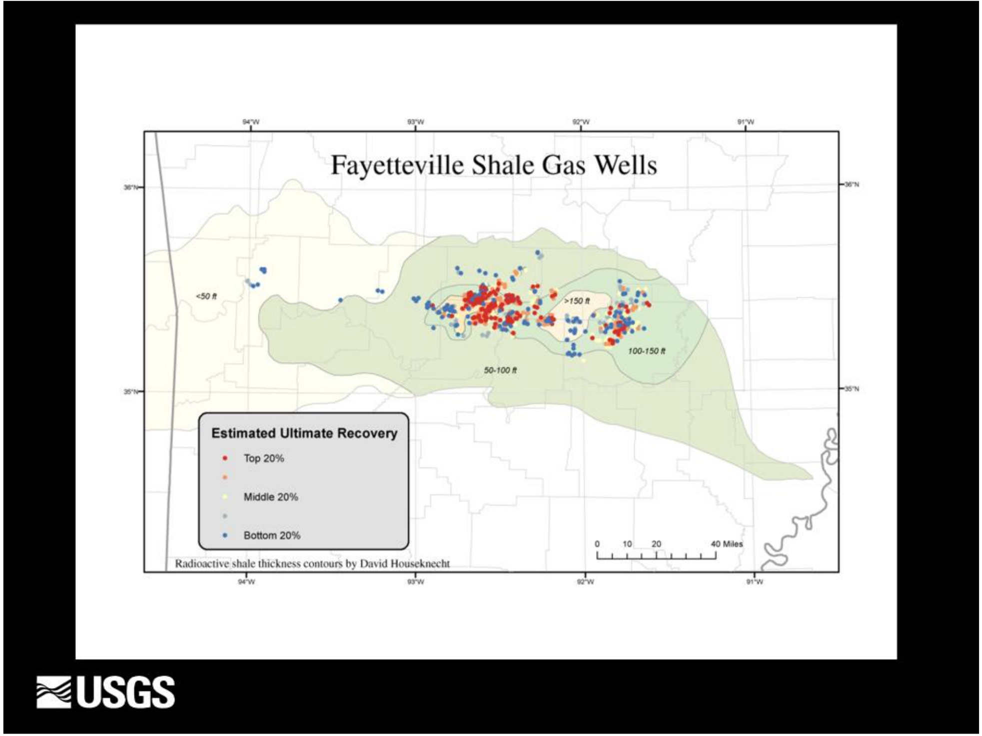


This map shows estimated ultimate recoveries (EURs) of Fayetteville Shale gas wells and how they cluster into sweet spots.



This map compares the well EURs of the previous map to the thickness of radioactive shale (as contoured by David Houseknecht, USGS). Note the moderate level of correlation between EUR and shale thickness.

Risk

- Divide the assessment unit into a quantitatively assessed area and an area that has no significant resource potential
- How much of the shale is a self-sourced reservoir?
  - >2% total organic carbon, and
  - Adequate maturity (thermal or biogenic)

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Quantitatively Assessed Area

- Option to divide the assessment area geologically into sweet spots and nonsweet spots
  - Not necessarily mappable at this time
- Each part has its own success ratio and its own EUR distribution

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Application to Data-Poor Environment

- Risk becomes much more important
- Uncertainty of mean EUR is large source of overall uncertainty
- Analog datasets

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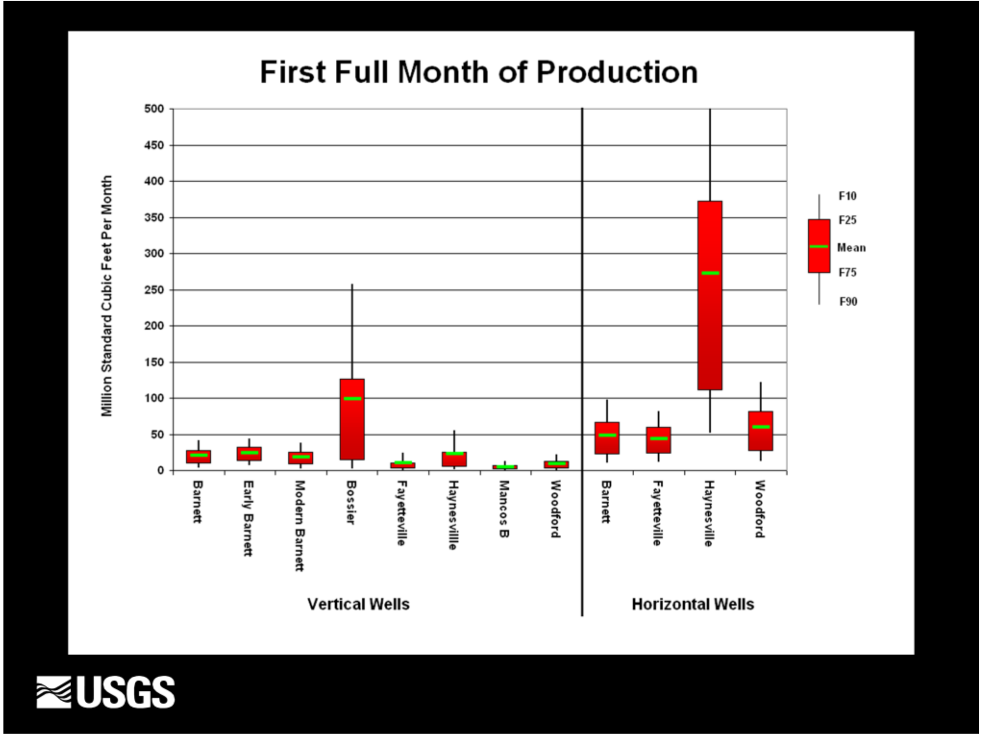
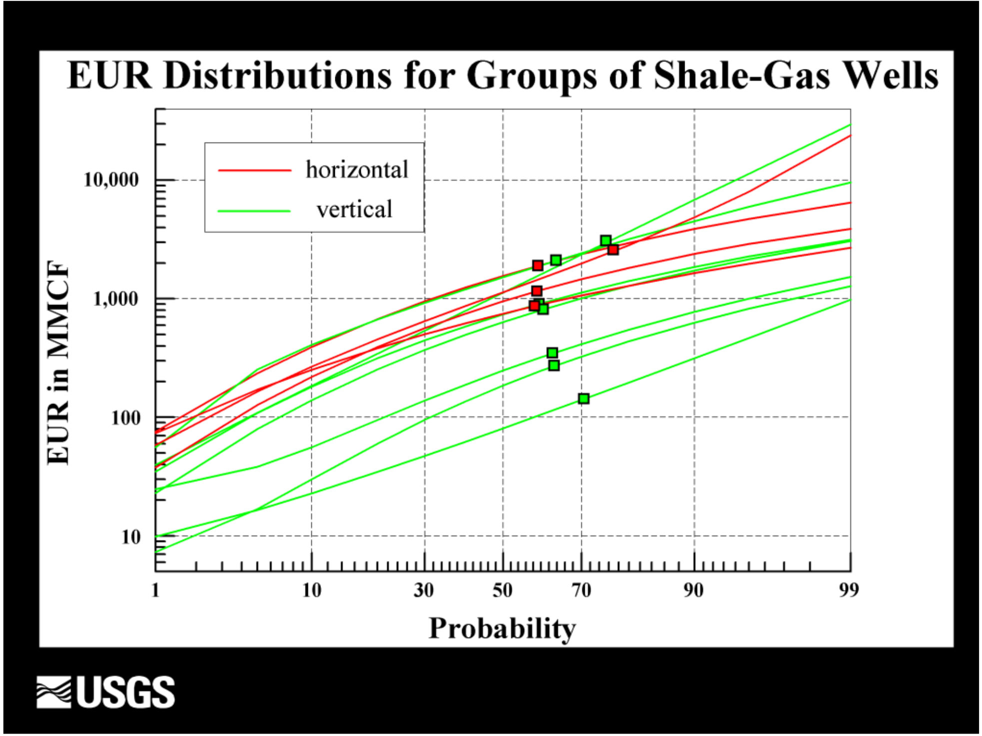


Comparison of several groups of shale-gas wells that could be used as analogs for assessments of data-poor areas. The box-and-whisker plots summarize the distributions of the first full month of production, which is commonly the highest monthly rate of production. Note the contrast between distributions of vertical and horizontal well productivities within the same formation. F90 denotes a 90 percent chance of at least the amount tabulated. Other fractiles are defined similarly.



This is another way of comparing EUR distributions for analog groups of shale-gas wells. Squares represent the mean of each distribution. Note the large variation among groups. For example, the means for vertical well groups differ by greater than an order-of-magnitude. MMCF = millions of cubic feet.

For more information go to:

http://energy.cr.usgs.gov/oilgas/noga/methodology.html

USGS