Success and Failure in Shale Gas Exploration and Development: Attributes that Make the Difference*

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Abstract

Unconventional shale-gas reservoirs are receiving increasing attention and have revitalized natural gas production in North America. Though costly and manpower intensive, they have less risk of a dry hole and can hold significant quantities of gas. With the current trend towards unconventional shale-gas plays, it is useful to examine the tools we use to explore for them. Attributes such as TOC, vitrinite reflectance, thickness, and mineralogy are touted as the path towards success. Using our extensive experience as operators in the Woodford shale in the Arkoma basin, we determined if these recommended properties actually are the main drivers, or if other properties play a larger role in a project's success or failure. In a horizontally drilled shale-gas play, due to reservoir heterogeneity within the field and stratigraphic section, sweet spots develop where wells with higher than normal IP rates and EUR values are common. We examined the sweet spots and attempted to determine the driving cause for their success. Additionally we examined areas with lower than expected performance to attempt to discern why. Our study resulted in determining that, although there are minimum required values for each of the typical exploration attributes, those minimum values are lower than would be expected, and there is a broad range in which highly economic production can be achieved. Additional factors relating to stimulating technique, reservoir temperature gradient, and nearby fault intensity proved to be the first order drivers of well performance. We concluded that current cut-off limits for exploration using TOC, thickness, vitrinite reflectance, and mineralogy are too conservative and should be expanded. Even where expanded they are useful as the initial check when examining a play; however, when determining acreage to purchase, better productive fairways, and even individual well predrill estimates, our identified additional factors, prove more useful.

Reference

Blakey, R.C., 2006-2011, Paleogeography and Geologic Evolution of North America--Late Devonian: Web accessed 25 January 2011, http://jan.ucc.nau.edu/~rcb7/namD360.jpg

Cardott, Brian, 2010, Application of vitrinite reflectance to Woodford gas-shale plays in Oklahoma: Presentation, 2010 SIPES Annual Convention, Colorado Springs, CO, June 21-24, 2010.

Websites/URLs

http://ic.ucsc.edu/~casey/eart150/Lectures/BrittleDef/brittleDef.html; Web accessed 25 January 2011.

http://jan.ucc.nau.edu/~rcb7/namD360.jpg; Web accessed 25 January 2011.

Success and Failure in Shale Gas Exploration and Development

Marcellus Shale | Woodford Shale | Barnett Shale

Attributes that Make the Difference

Jesse Gilman

Chris Robinson

Presenter's notes: I would like to thank my employer, SM Energy, for allowing me to present our findings. This work would not have been possible without the help and ideas of my friend and colleague Chris Robinson. After working in the Woodford shale play for the past 3 ½ years, we have taken a look back at production results and determined we need to modify our exploration tools, as well as alter our development strategy, in order to achieve economic success. Presented here are the results of our study. ,

Agenda

- Commonly expressed desirable shale attributes
- Introduction to the Woodford of the Arkoma Basin
- Examination of each attribute to assess impact on production
- Discussion of additional factors
- Conclusions

Presenter's notes: The above items will be discussed, in trying to answer which tools are important in the successful exploration for, and economic development of, a shale-gas play. First, we look at the shale attributes used for exploration.

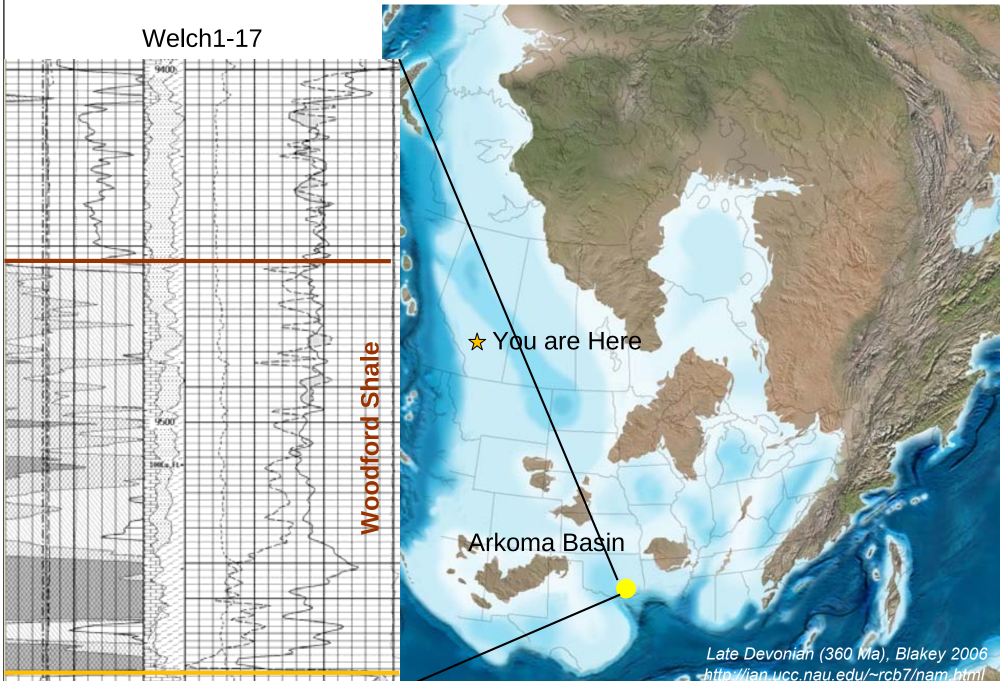
Assumed Desirable Shale Attributes

- High TOC - >2% but the higher the better
- Mineralogy – high silica or calcite content, low clay content
- Porosity and Permeability – higher is better
- Thickness – the thicker the better
- Vitrinite Reflectance – between 1.25 and 2.0%
- Fracturing – want a fractured reservoir (increased P&P)

Presenter's notes: Attributes listed here are commonly described as desirable when examining shale plays.

While we certainly are interested in the organic material, mineralogy, and P&P data, in this presentation, focus is on the lower three items in the list. We shall also look at two additional factors, using hindsight to determine if we need to modify our exploration and development techniques. The data used are from the Woodford Shale of the Arkoma Basin.

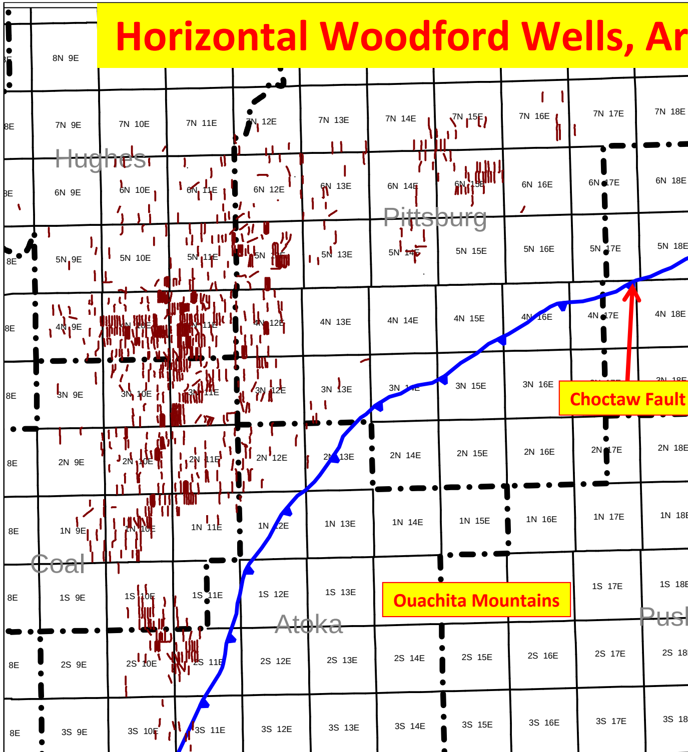
The Woodford Shale Depositional Environment



Presenter's notes: One of Dr. Blakey's paleogeography maps showing the continent during the time of Woodford deposition in Late Devonian. Calgary is located as well as the Woodford of the Arkoma Basin. The Woodford was deposited on the continental margin in mostly anoxic waters. The Woodford Shale is easily identified on a log due to the extremely high gamma-ray response. The Woodford is made up primarily of illite and silica, forming interbedded layers of shale and chert.

The Woodford Shale in Outcrop

Horizontal Woodford Wells, Arkoma Basin



Arkoma Basin Woodford

- 850 horizontal Woodford wells
- Cumulative production **543 BCF and 307MBO**
- Drilling started late 2005
- Average well EUR **2.1BCF**

- Several generations of geological interpretation, drilling, and completion practices as learning curve has improved

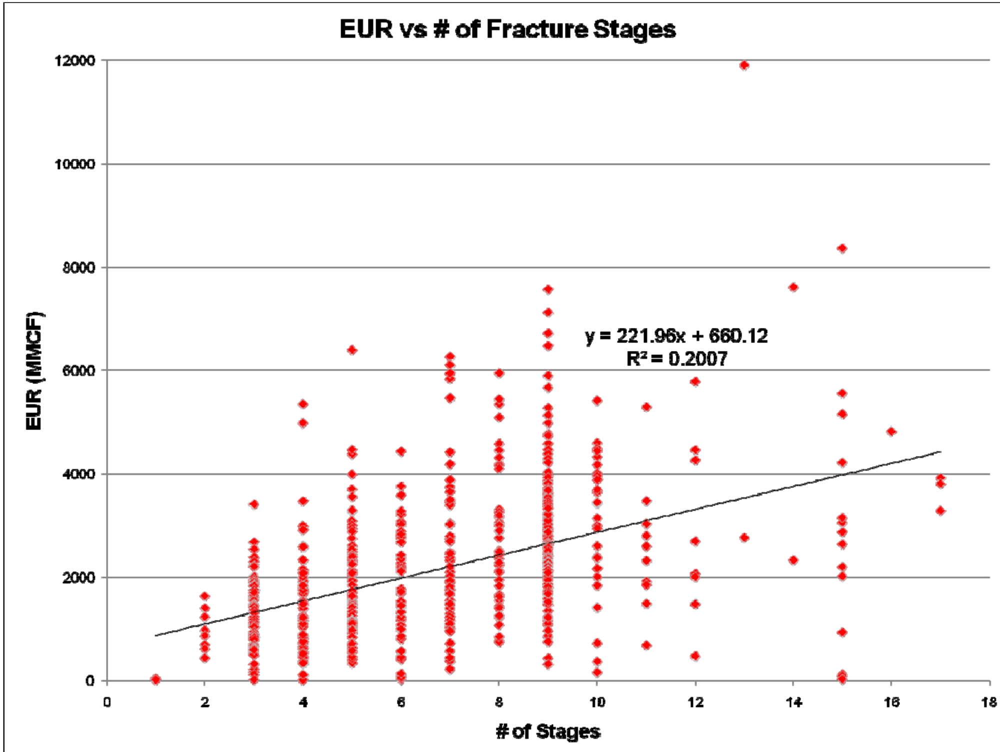
Presenter's notes: Focus is on the Arkoma Basin, bounded on the south by the Ouachita Mountains, south and east of the Choctaw Fault. Over 850 horizontal wells have been drilled over the past five years in the Woodford, which have produced over ½ TCF of gas. Note that the average well's EUR is 2.1BCF.

There is a complete learning curve for a shale-gas play in the Woodford. You can follow the transition from vertical wells to 10,000' laterals and number of stages from 3 to 20. There is a large amount of 3D seismic, vertical well logs, and cores covering the play. It is this robust data set, in addition to the wells we have drilled, that has led to our theories and understanding of the play.

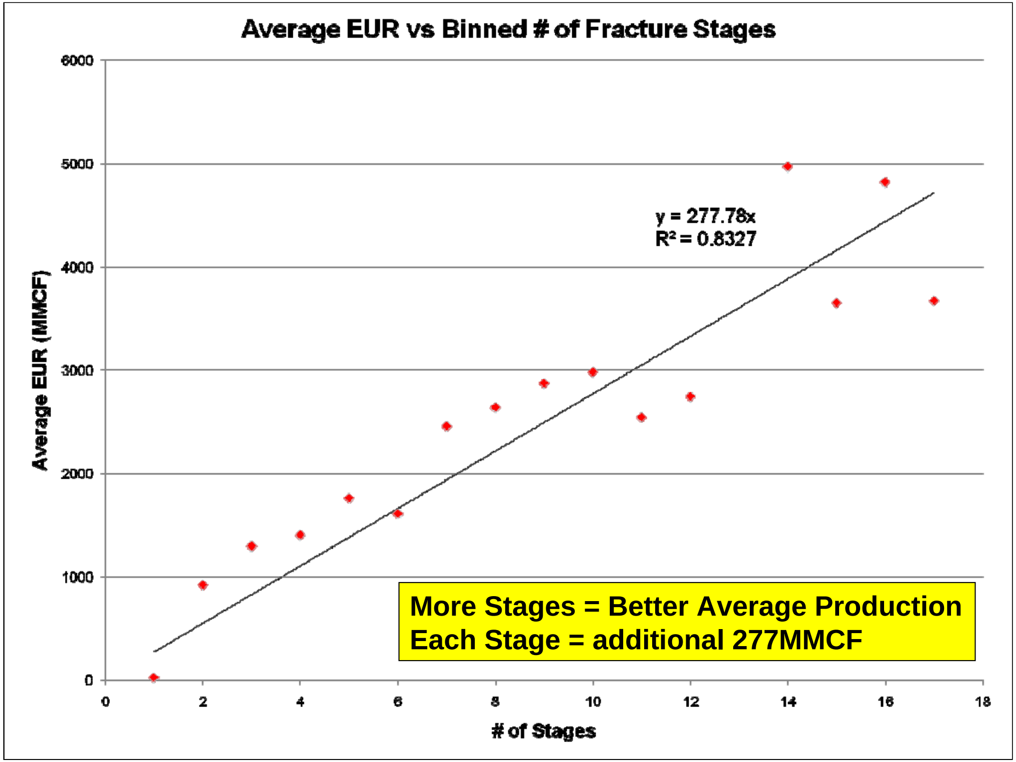
Lateral Length and Completion Impacts Production

- The longer your lateral is in the shale, the more stages you can complete
- The more stages you complete, the more induced fracturing, increasing the surface area open to the rock
- *We are trying to produce from a seal:* low-porosity, low-permeability rock
- Over life of the play
  - Lateral length increases
  - # of stages increases
  - Stage spacing decreases

Presenter's notes: We are trying to produce from a seal; the more wellbore in the formation, the more rock in contact with your completion. Over time the lateral length and the number of stages per well have increased, and this has impacted reserves significantly.



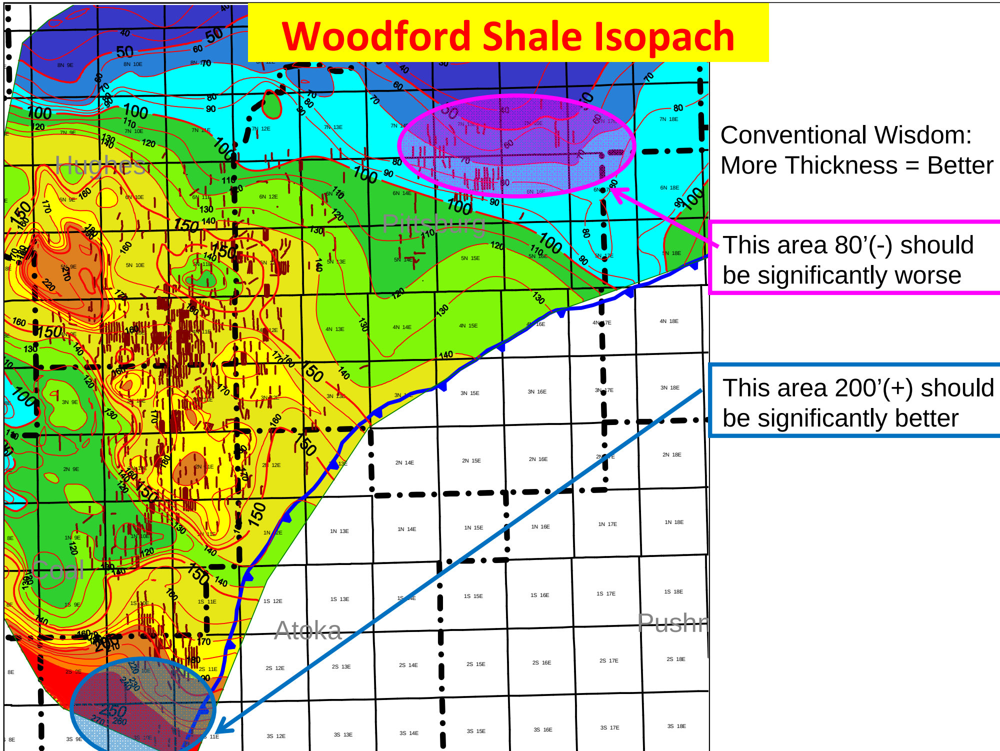
Presenter's notes: Throughout the presentation, the EUR of each well will be on the Y axis of our plots in million cubic feet, and the examined attribute will be on the X axis. Here is the plot of the EUR and number of fracture stages per well for over 600 wells in the play. There is a trend towards increasing production with the number of stages per well; however, there is a lot of scatter. We interpret this scatter to be due to multiple additional factors influencing production. To try to account for some of this scatter, we have averaged the EUR values for all wells in each number of stage bin.



Presenter's notes: In general (average EUR versus stage), additional stages add additional reserves. In this case about an additional 300MMCF of gas per stage. It is expected that at some point there will be a break-over point, where additional stages add less and less reserves, but it does not appear we have as yet reached it. We have not seen significant interference of stages and perforation clusters being placed too close within a well. The Woodford Shale is a seal, more frac stages in general do a better job breaking-up the rock and allowing more drainage of the formation.

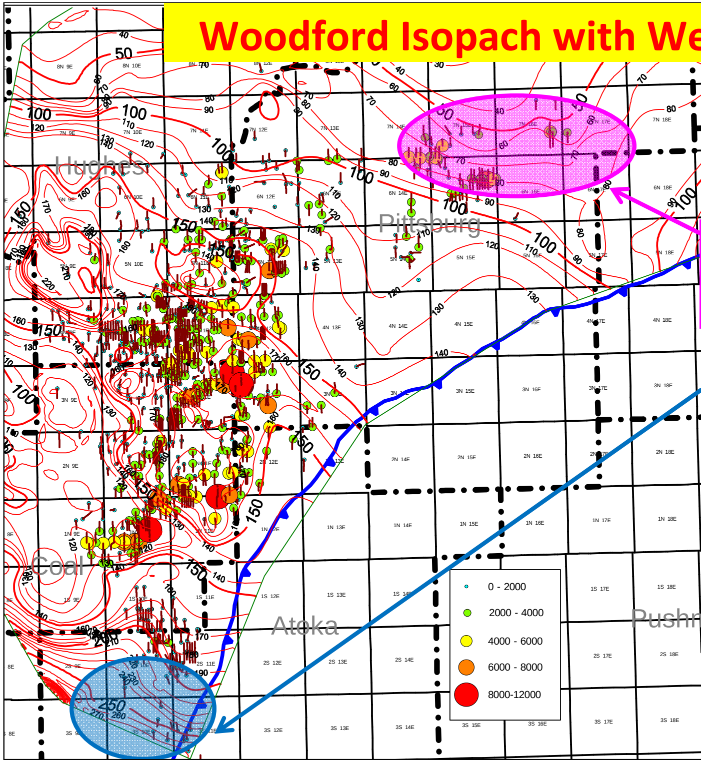
For the Marcellus shale, comparing IP vs number of stages shows the same trend; more stages result in higher IP.

We now can account for this relationship and try to remove the impact of number of stages on a well as we examine other attributes.



Presenter’s notes: Commonly when evaluating shales, we are concerned about the thickness of the formation. If thickness is a driver of production, one would expect the highlighted region in the south, where it is more than 200’ thick, to be the best. The region in the north, with thickness of less than 80’, might be expected to yield relatively poor results.

Woodford Isopach with Well EUR

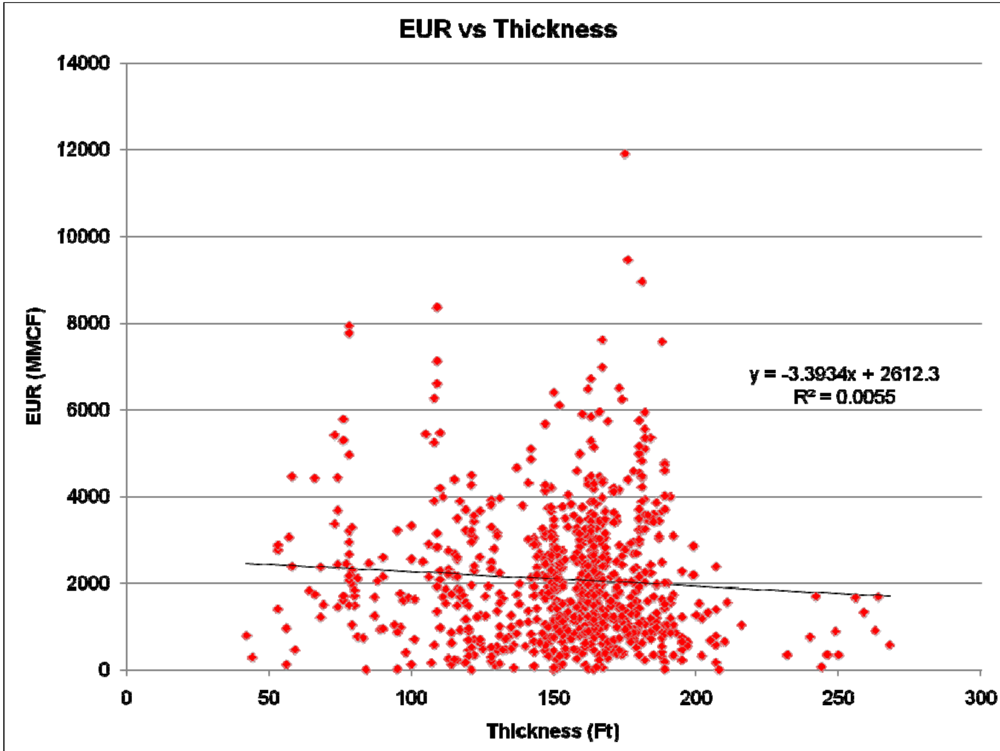


Reality:
More Thickness ≠ Better

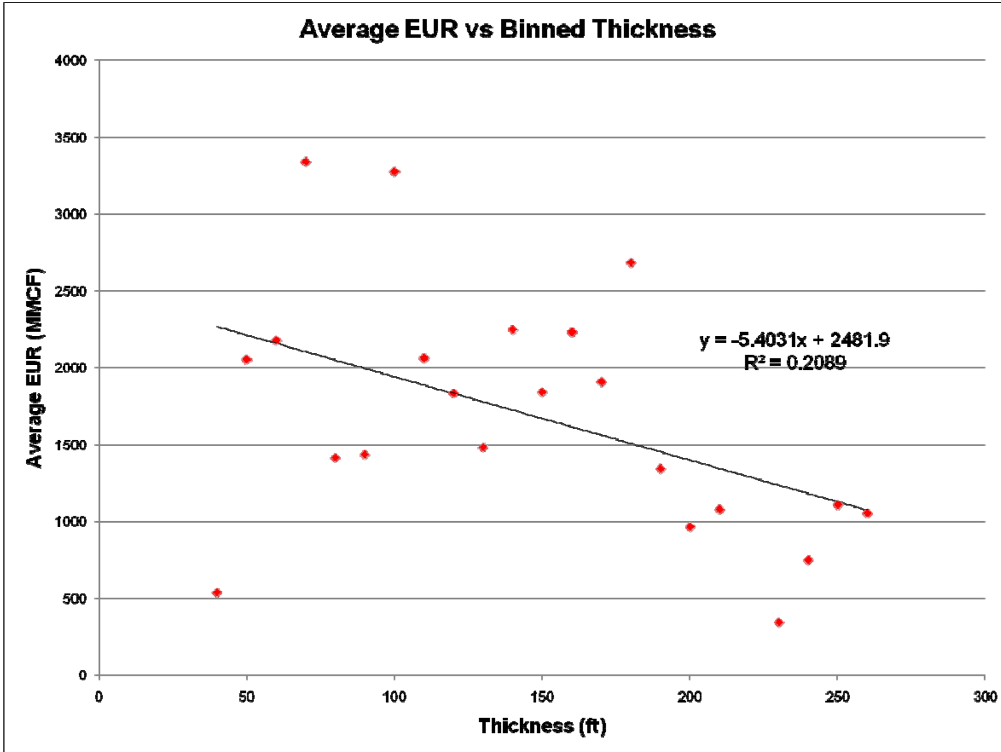
14 wells >3BCF,
two> 7BCF
56% > Woodford average

1 well in 25 > Woodford average
Wells average < 1BCF

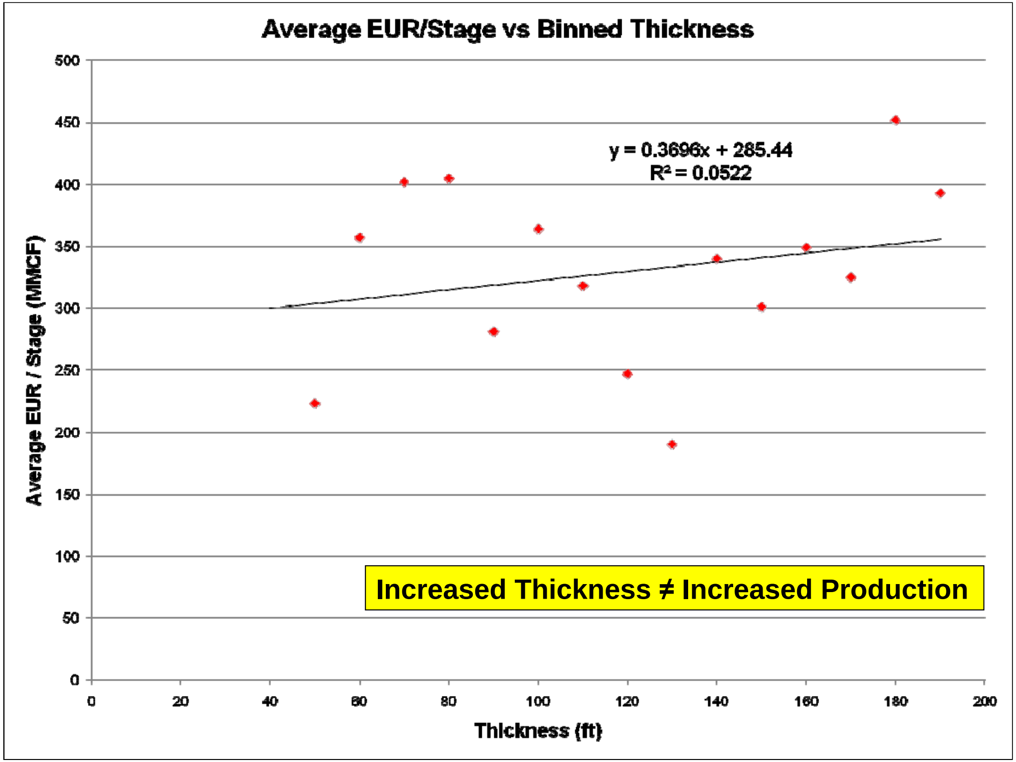
Presenter's notes: However, in this case, production does not depend directly to thickness. Bubbles reflect each well's EUR. The largest bubble is 8-12 BCF, and the smallest bubble is less than 2 BCF. In the thin area are good results. Remember that the industry average is 2.1BCF per well; in the area of thin Woodford, more than half of the wells are greater than the average, and two are more than 7BCF. In contrast, the area of thick Woodford, only one well is better than the industry average; in fact, if the area is expanded to double the number of wells, there are only three that are better than the industry average--with more than 160' of reservoir.



Presenter's notes: In the gross data, there does not appear to be a trend correlating EUR with thickness; to possibly reduce scatter, we averaged the EUR for discrete thickness bins, just as we did with number of stages.



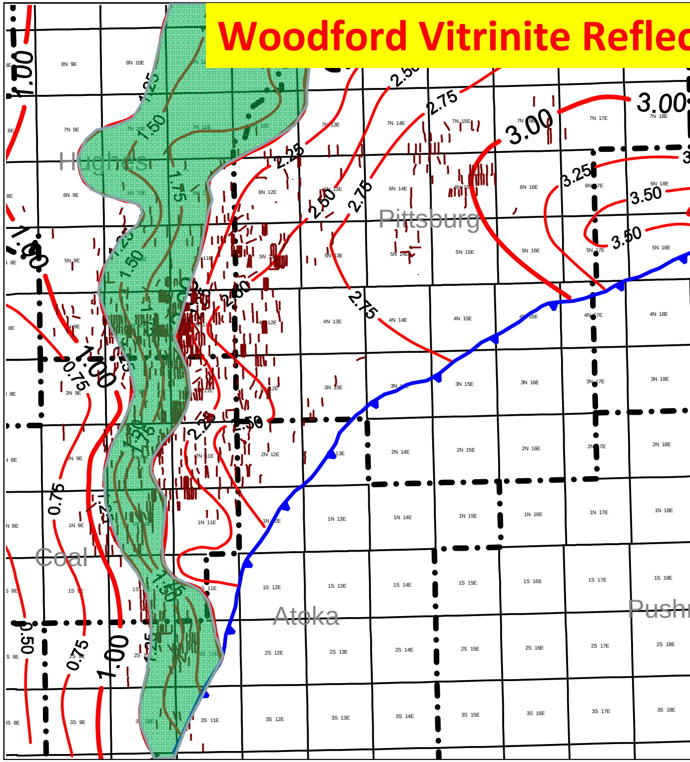
Presenter's notes: Averaging the EUR for discrete thickness bins does not show a correlation between thickness and production, but there is one more step of normalization that may be taken. The EUR is divided by the number of stages in order to see if the area with thicker Woodford suffered from poor stimulation.0



Presenter's notes: Average EUR per stage, shows that there is no correlation between thickness and production. I think that we do not understand very well what effectively stimulated rock volume is, as well as the recovery factors. Our interpretation is that with a 200'-thick section of rock, you cannot effectively stimulate and prop open fractures in the entire 200' column; in reality you are draining a much smaller section of the shale.

If Thickness, above a minimum, is not a major exploration factor, we now examine Vitrinite Reflectance to determine its role.

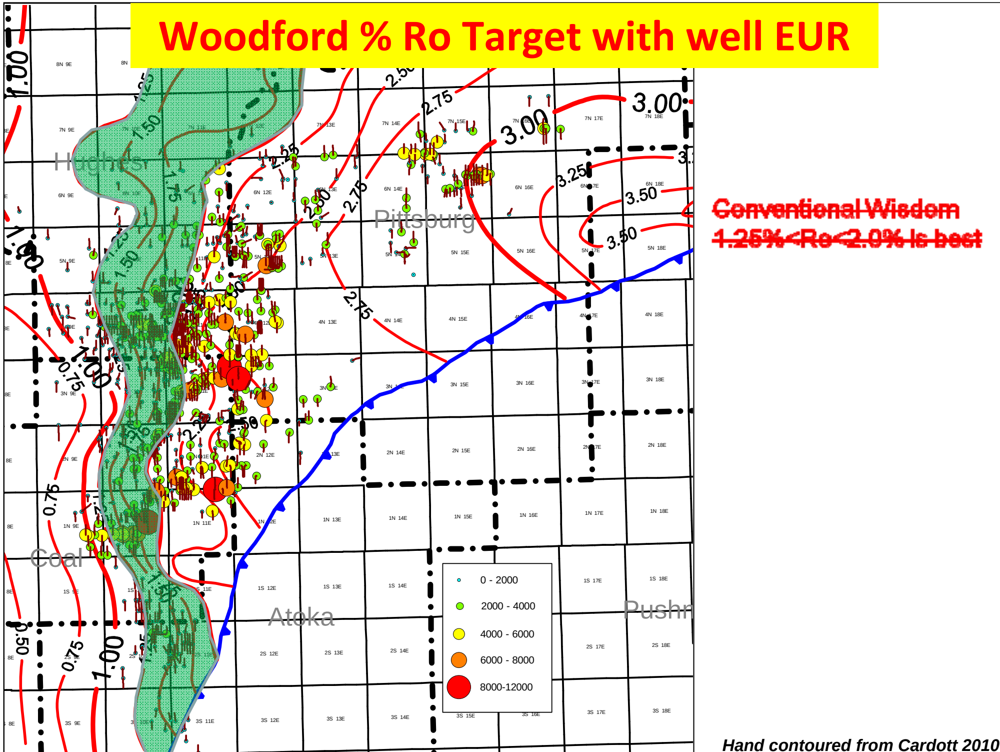
Woodford Vitrinite Reflectance



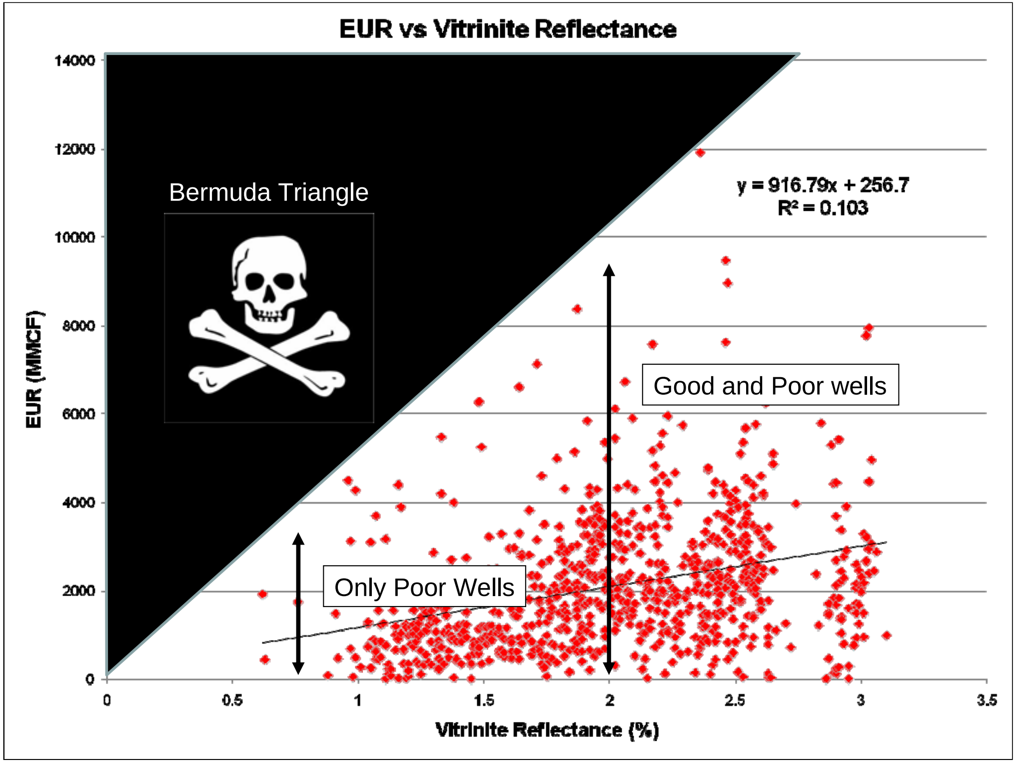
Conventional Wisdom
1.25%<Ro<2.0% is best

Hand contoured from Cardott 2010

Presenter's notes: This map of the Arkoma basin uses data gathered by Brian Cardott. In general thermal maturity increases eastward. Range of values between 1.25 and 2% (shaded area) is fairly standard when shale plays are discussed and evaluated.

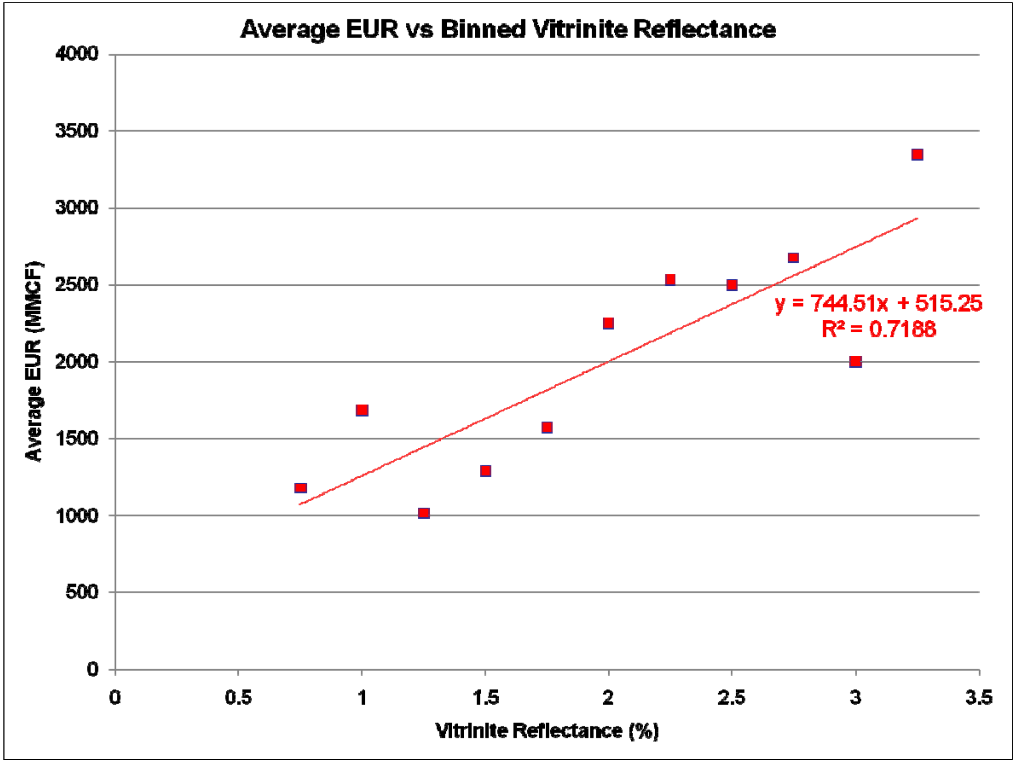


Presenter's notes. The range does cover a few good producers; however, most of the best wells are outside it.

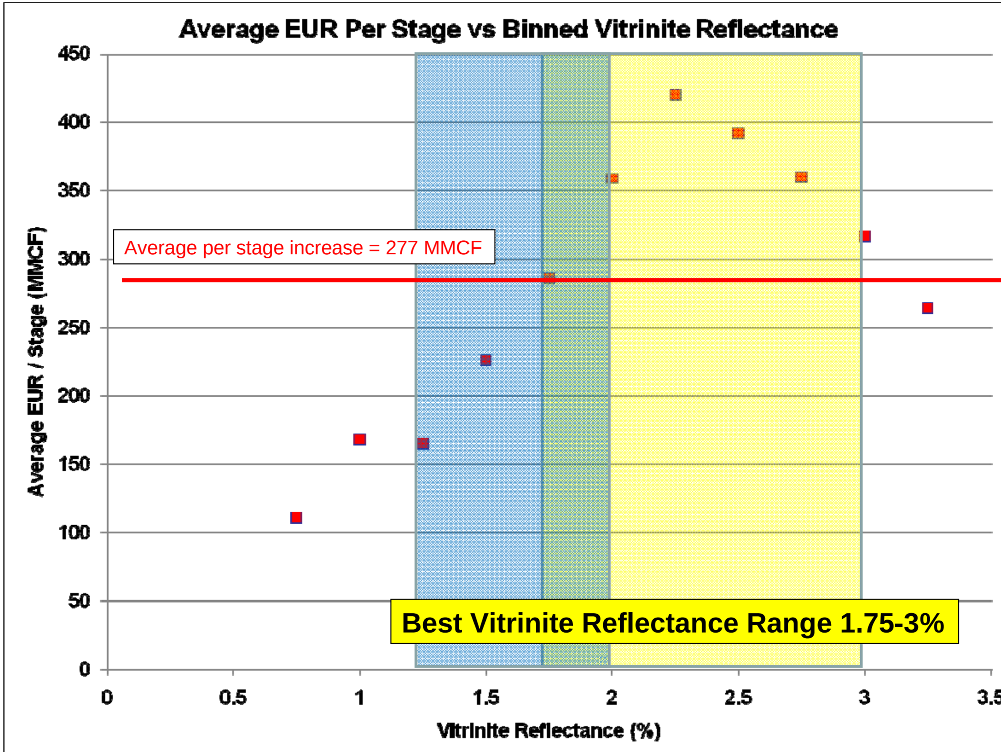


Presenter's notes: Well EUR is plotted against the interpolated vitrinite reflectance.

With 800 wells, there is considerable scatter, but there is a trend. Our interpretation is that multiple attributes impact the production of hydrocarbons. A triangle of data shows a general trend, but in reality a 2% Ro well may result in 8 BCF or it could be .5 BCF. On the other hand, a .75% Ro well will yield only a poor result. The Bermuda triangle in the image is where no data exists.

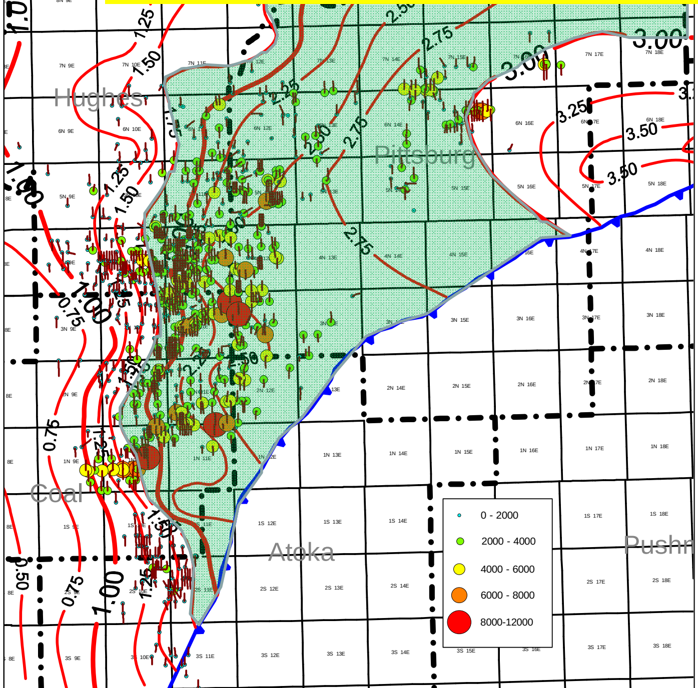


Presenter's notes: We binned the data, averaging EURs for vitrinite reflectance ranges. Plotted here are the results. A decent correlation indicates that reserves increase with an increase in thermal maturity. It should be noted that in this evolving play, over time, operators have pushed into areas with higher thermal maturity. We must account for the number of stages.



Presenter's notes: When the number of stages is considered, there is a definite break-over where increasing Vitrinite Reflectance starts to be detrimental. Our explanation in gas shales is that the majority of the porosity is in the organic matter created and/or maintained during hydrocarbon generation and expulsion. With increasing thermal maturity there is increased porosity development within the organic matter, and up to a point improved performance. However, at maximum generation, thermal decay of gas occurs, with formation of higher quantities of CO2. If we use the average EUR per stage, we shall drill areas where each stage adds 277MMCF or greater. Our target changes to between 1.75 and 3% Ro, not between 1.25 and 2%.

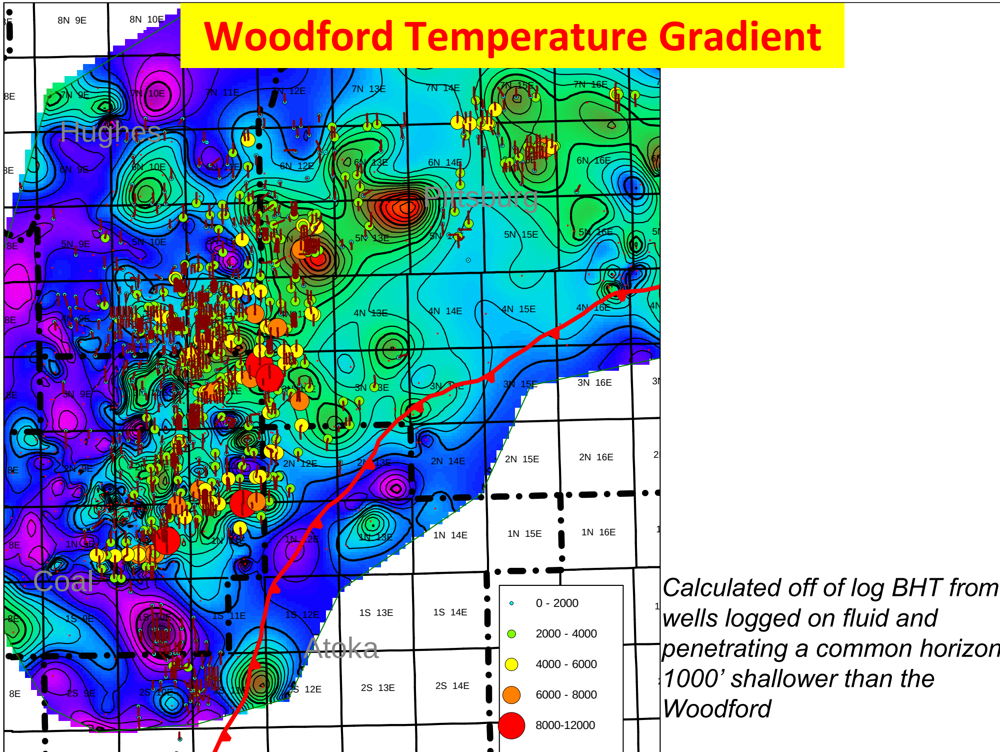
Woodford New %Ro Target with Well EUR



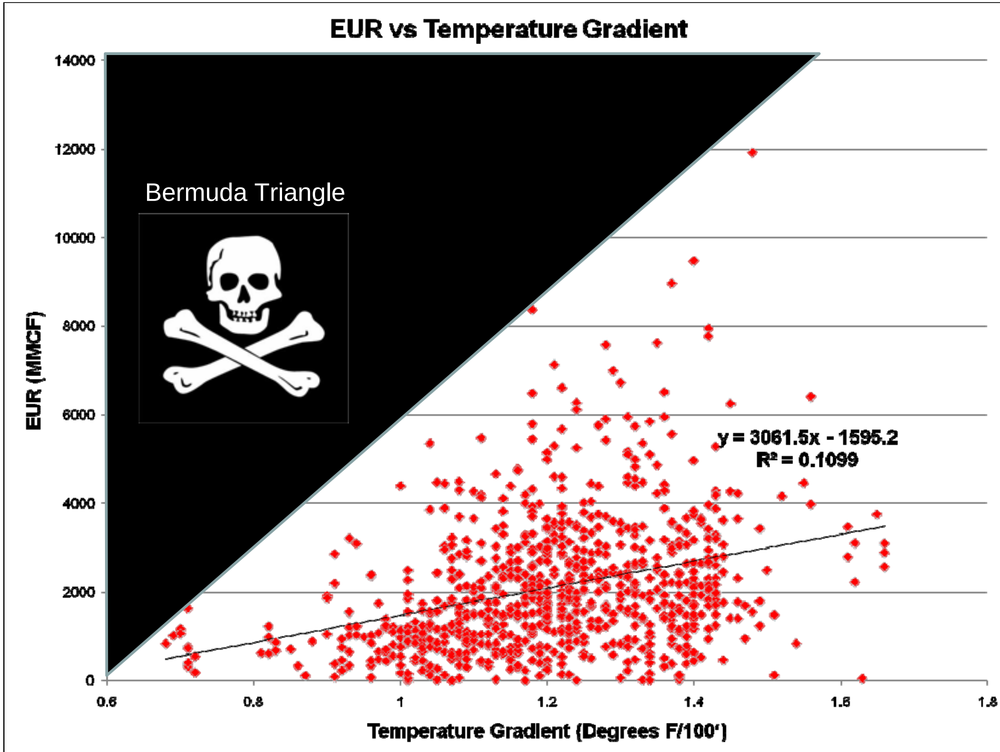
Empirical Wisdom
1.75%<Ro<3.0% is best

Hand contoured from Cardott 2010

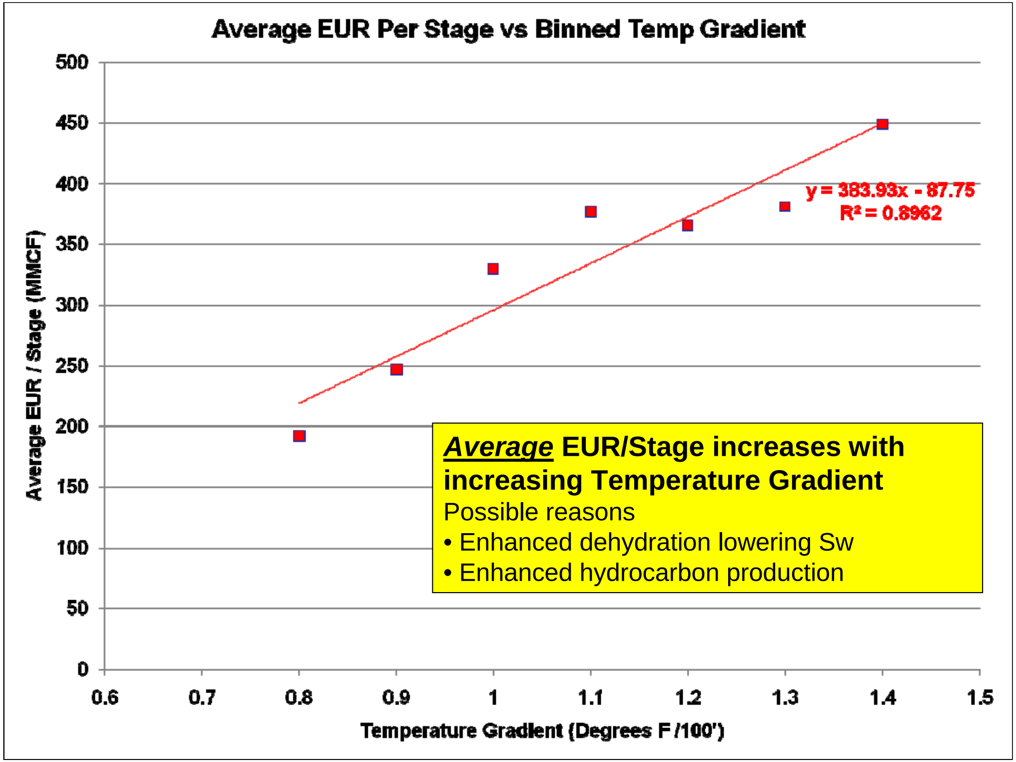
Presenter's notes: The revised area of interest covers a significantly larger region for the play. While this is approximate, by and large this would eliminate many of the poorest wells.



Presenter’s notes: This attribute might seem somewhat unrelated; yet a map of the temperature gradient, by dividing well-log maximum-recorded temperature by the depth is informative. Even with issues associated with some of this data, we think that general trends are captured. The higher temperature gradient areas appear discretely and do not follow vitrinite reflectance contours. In fact, you can trace one vitrinite reflectance contour across extremely low and extremely high temperature gradient areas. Visually, it appears that in the higher temperature gradient regions there are better EURs and areas of lower gradients have poorer EURs.



Presenter's notes: Statistically, our gradient data plotted within a triangle shows that wells with a high temperature gradient may be good or poor; lower gradient wells are poor. Temperature gradient adds another piece to a working solution.

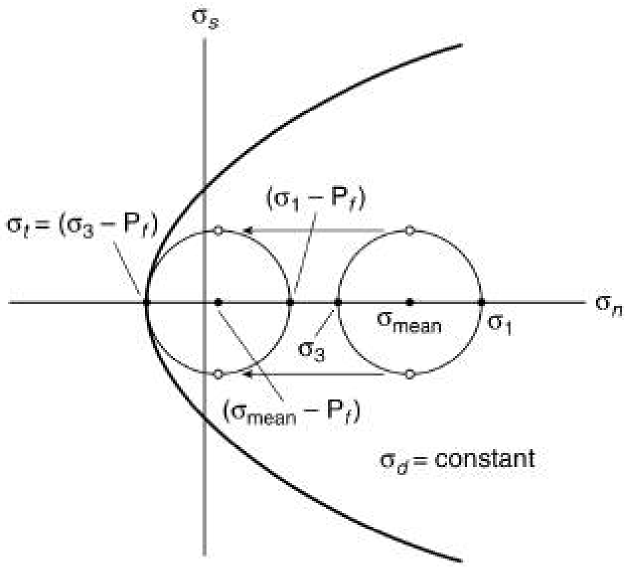


Presenter's notes: The plot was obtained with binned data and by accounting for the number of stages. In general, with an increase in temperature gradient, there are more reserves per stage. We have spent a lot of time trying to determine why temperature gradient might impact production. One of our theories is the possibility that additional dehydration of the rock has occurred; as the amount of water vapor soluble in methane is related to temperature and pressure, areas with higher temperature gradient may have had enhanced dewatering during hydrocarbon generation and expulsion. Another theory, called "the Brisket theory," is that vitrinite reflectance reflects only the maximum temperature, but in an area with a higher temperature gradient the rock may have remained in the hydrocarbon generation window longer, cooling slower. This extra cooking may have generated more pore space in the organic material. Regardless of the reason, what seems clear is: if you are drilling a well to 10,000' TVD, you want to be in an area where the temperature is 200 degrees, rather than one with 150 degrees.

Shale Fractures in Core and Outcrop

Presenter's notes: Fracturing is often discussed as of utmost importance in a gas shale, and I think it is misunderstood. Here is a picture of the highly fractured Woodford Shale in outcrop; fractures are everywhere, some healed, some full of dead oil, most open. When the play first began, we visited outcrops and put together an image of the pay: with fractures are fracture porosity and higher perm pathways. However, when we started looking at core photos, and FMI logs through the Woodford, most commonly drilling and coring induced fractures, not open ones. What is in the outcrop is not what is in the subsurface, where the Woodford is not a highly fractured, enhanced P&P shale. This is not the case just in vertical wellbores; from horizontal FMI logs in this and other fractured shales, open fractures are almost non-existent in the subsurface. In outcrop, what is seen are the results of exhumation and associated fracturing, as predicted by reference to Mohr-Coulomb fracture criteria.

Mohr's Circle and Fracturing



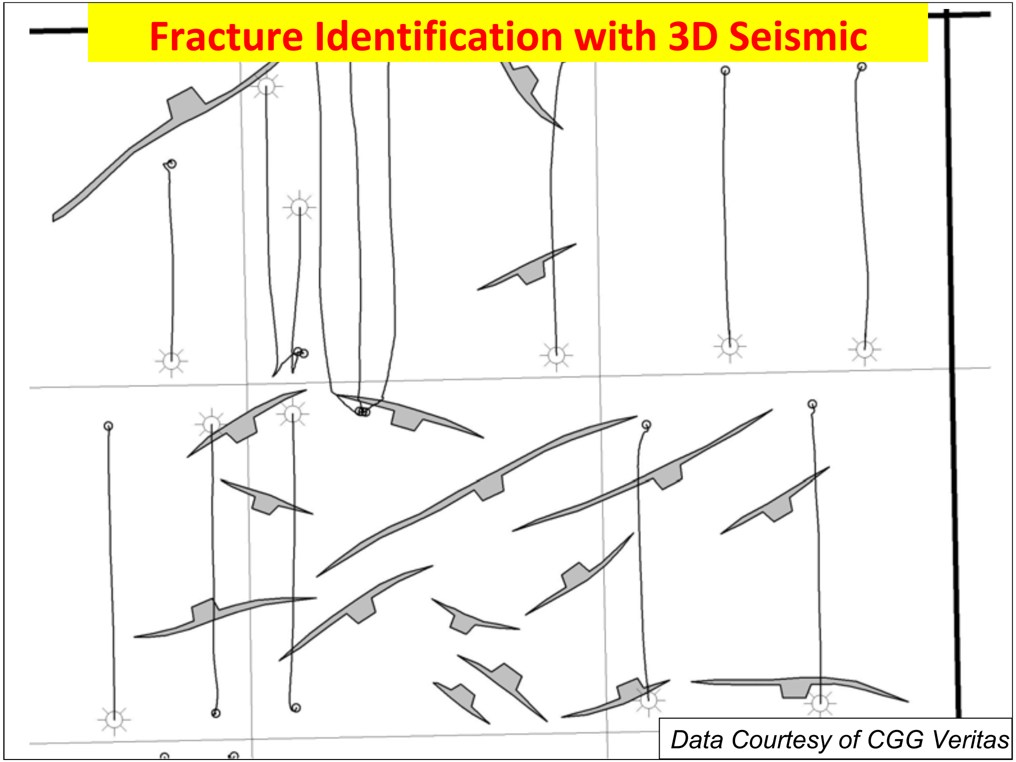
Exhumation: σ_1, σ_3 decreases leading to failure

Stimulation: pore pressure shifts σ_{mean} leading to failure

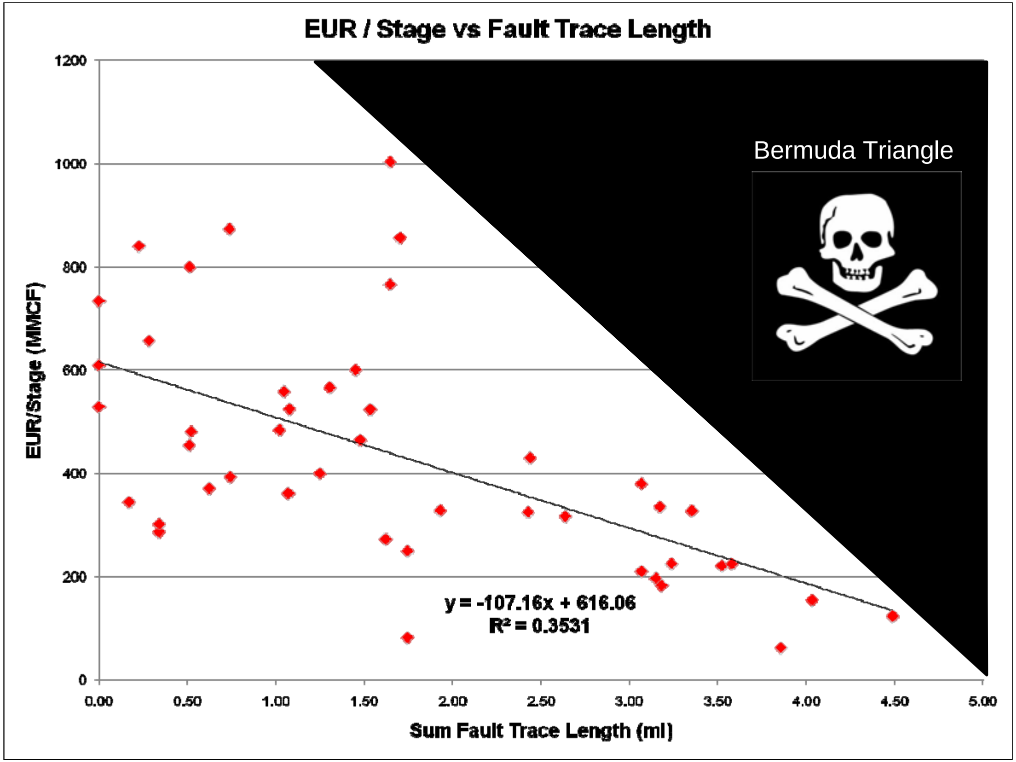
http://ic.ucsc.edu/~casey/eart150/Lectures/BrittleDef/brittleDef.html

Presenter's notes. Using Mohr's circle, one can show the line at which the rock will fracture. As the rock is exhumed, overburden, sigma 1, and sigma 3 decrease, and the circle shifts to the point where the rock will fracture, resulting in what we see in outcrop. However, in the subsurface, sigma 1 is high, and the shale is a seal, which has served as such for many years for conventional plays. If the fractures in outcrop occurred in the same manner in the subsurface, the shales would be very poor seals When we frac a well, the fluid-pressure part of this equation is changed, and the circle shifts again to the fracturing point. In essence we try to make the rock look like it does in outcrop. We have actually seen that in heavily fractured areas prior to drilling; the result may be a poor well.

Fracture Identification with 3D Seismic

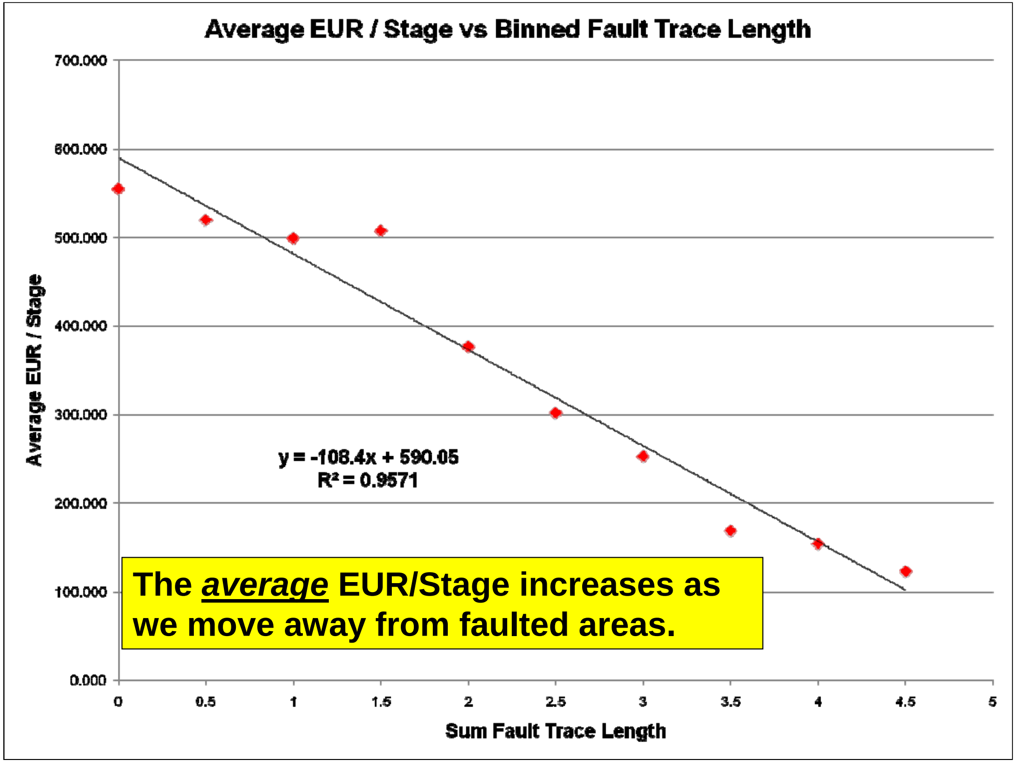


Presenter's notes: Because we cannot directly see how fractured the Woodford is in the subsurface, we are using 3D seismic as a proxy to identify faulting; after all, a fault is just a fracture with slippage. Our theory is that where faults occur, there are multiple, smaller fractures that you cannot image with seismic. Here faults are shown in a small part of our acreage. There are "calm," stable areas, heavily faulted areas, and local areas in which wells do not cross faults but are in the vicinity of them. We have found there is a relationship between the EUR per stage and fault intensity in the immediate area around a well.



Presenter's notes: For the data plotted here, we used only our wells that are covered by 3D seismic and drew a one-square mile box around each well. We then totaled the length of the fault traces within the box. The one-square mile was chosen semi-arbitrarily; in our fracture treatments we have determined that the proppant travels at least one-half mile, and frac water travels at least one mile from the well being stimulated. The data plots within yet another triangle.

In lightly faulted regions there are good and poor wells, but in heavily faulted areas, there are only poor wells.



Presenter's notes: When the data are binned in order to try to reduce the scatter, it becomes clear that being close to numerous faults, i.e., fractures, results in poorer EUR/Stage. We think this is due to faults "stealing" the frac energy and causing ineffective fracturing of the shale; the more faulting, the more potential leak-off zones. We have seen this occur in several micro-seismic surveys run during stimulation. Even small faults can divert a large amount of your stimulation.

Conclusions

- Adjust our exploration tools
  - Remove thickness criteria
  - Shift vitrinite reflectance range
  - Add temperature gradient mapping
  - Avoid heavily faulted regions
- Adjust development plan
  - Using 3D, clearly identify and target un-faulted regions
  - Drill long laterals with lots of stages
  - It is OK to let poor acreage When we bin the data to try and see through this scattergo
- ***Why settle for average? Only drill the best***

Presenter's notes: Using the Woodford as an analog, we have shown the need to adjust our exploration tools, removing thickness or drastically reducing our minimum, changing the range of vitrinite reflectance we target, preparing temperature gradient maps, and avoiding known largely faulted areas. Once in development of a play, 3D seismic is imperative to high-grade acreage away from faults. Drill longer laterals and add more stages early, as you cannot go back and "do it right" later.

Drilling a well on sub-average acreage to hold leases to allow you to drill more sub-average wells in the future is foolhardy. As much as people want to make these plays simple, "flat and black, work everywhere plays," they are not. You need geological thinking and a critical eye. The average well in the Woodford is 2.1BCF, which is uneconomic at current gas prices, but with some work and thought, you do not drill the poor wells, and then you are exceptional.