Operational and Business Efficiency in Unconventional Projects*

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Abstract

In order to extract maximum value and benefit from unconventional oil and gas projects, companies must recognize the need for a fully integrated business and operational approach. An integrated approach starts with a probabilistic assessment of the production potential of a region based on a solid geotechnical foundation, but true maximization of value can only be realized from operational efficiency within an integrated business context.

Companies are forced to make large development decisions using scant real data. As such, it becomes critical to understand which learning objectives will have the greatest impact when fulfilled. Projects are phased and each activity must take uncertainty into account in order to achieve reliability and reduce investment risk. These activities include:

- Characterizing the resource potential.
- Quantifying the production uncertainty by well and project aggregate.
- Conducting efficient early development testing using the best available technology.
- Leveraging the early results to provide a reliable competitive advantage.
- Developing and implementing a sound competitive plan.

Factors controlling the distribution of gas resources include organic richness, maturity, gas content, and gas saturation state, in addition to conventional elements such as porosity and water saturation. While reviewing the available core and log data it is critical to assess their variability and underlying controls as limited data may not be fully representative of in-situ reservoir properties.

Two thirds of the value uncertainty in a typical unconventional gas play is attributable to production uncertainty. This can be reduced through the use of state-of-the-art technologies such as reservoir models capable of better predicting well performance profiles and recoveries. This type of technology needs to be part of a larger plan to quantify critical unknowns, and to show their business impact.

Thresholds for pilot well performance as well as early development need to be assessed prior to the pilot phase of a project. If well planned and executed, a company's play entry and early development strategy can lead to value maximization, competitive advantage, and downside risk mitigation (early and clean exit when warranted). Competitive advantage is both the driving force, and the reward for good decision making in unconventional plays.

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Weinman Geoscience, Barnett Shale Prospecting with 3D Processing and Analysis

Operational and Business Efficiency in Unconventional Projects

Decision Strategies

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Presenter's Notes: The title of my talk today could just as well be "Estimating Prospective Resources, Contingent Resources, and Reserves in Shale Gas Accumulations:
What do I have? How Do I know?"

And I would argue, at the onset of my talk, that this issue should command our attention for at least two reasons.

Reserves are the Basis of Corporate Value

- Over 150 publicly-owned U.S. oil and gas producers file reserves data
- Their total reported oil and gas reserves are valued at over $3 trillion
- Proved reserves account of over 70 percent of their total market value
- Inaccurate estimates cause serious problems
  - Reserve write-downs
  - Poor planning and managerial decisions

From B.G. Dharan, "Improving the Relevance and Reliability of Oil and Gas Reserves Disclosures," Presented to U.S. House Committee on Financial Services, July 31, 2004

Presenter's Notes: The first reason is that reserves are the basis of value for oil and gas corporations.

In the U.S., over 150 publicly traded companies file reserves data, and their total reported reserves are valued at over 3 trillion dollars. This accounts for about 70% of their total market value.

So if you don't get the reserves numbers right, especially the proven reserves numbers, this can lead to serious problems.

We're all aware of companies that have had to write down proven reserves, but in addition, inaccurate estimates can cause companies to focus on the wrong fields and the wrong projects, resulting in significantly poorer financial performance.

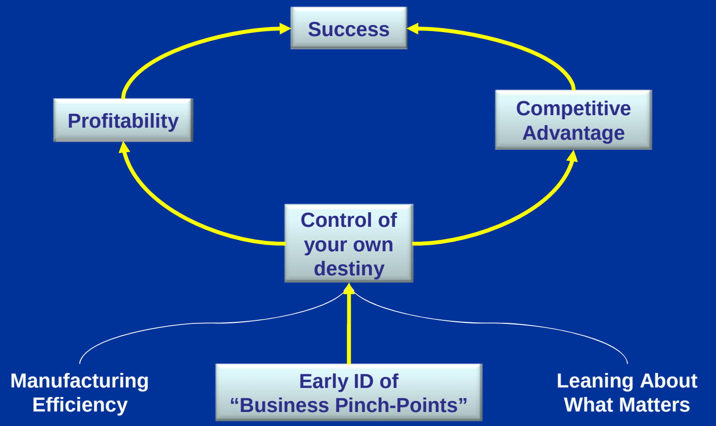
Resources and Reserves are Critical For…

- Determining division of ownership
- Calculating a fair market value
- Raising capital for development
- Establishing sales contracts and prices
- Obtaining regulatory approvals
- Designing and constructing facilities

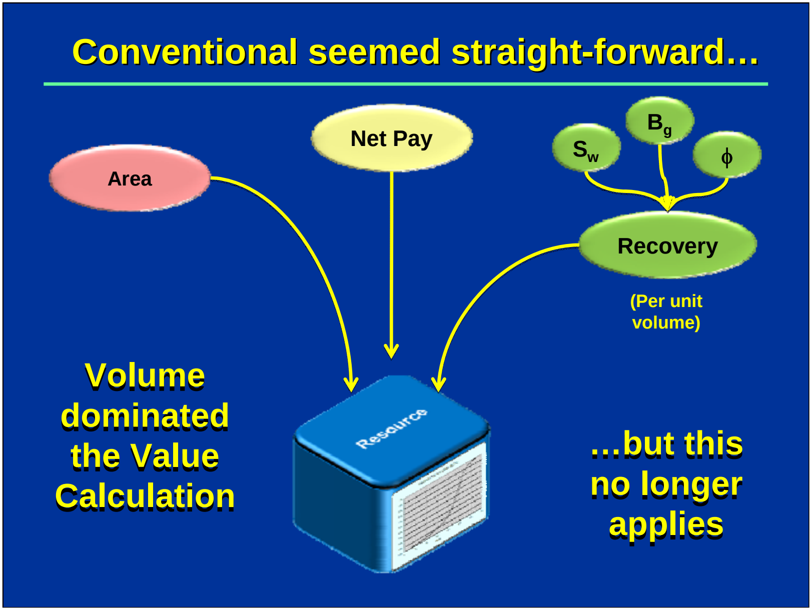
Presenter's Notes: The second reason this issue should command our attention is that resource and reserves estimates are critical to all the major transactions that take place in the industry. These include

1. Determining the division of ownership
2. Calculating a fair market value
3. Raising capital for development
4. Establishing sales contracts and prices
5. Obtaining regulatory approvals
6. Designing and constructing facilities

But Success is More Than Just Reserves



Unfortunately, most technical teams don't think "Business"


Conventional seemed straight-forward…
Area
Net Pay
S
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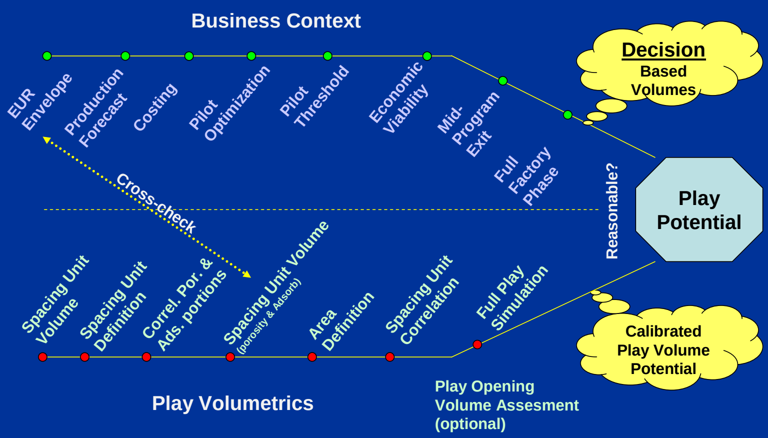
Recovery
(Per unit volume)
Resource
Volume dominated the Value Calculation
…but this no longer applies

Unconventional Play Potential Work Flow



Business and Operational Efficiency…

Is all about rapid learning and expert implementation.

- Prioritize your work and Learning to the Decision Critical Items… the things that matter

- Have a Learning Plan

- Understand what leads to downside outcomes and apply decision thresholds

Learning Priorities

What you have → The Rocks and the Product

What you Do → The Drilling and Completion

What it Costs → Economics

There are Two types of Learnings

Discrete - chance events that are either present or not present for a given area…

- Productivity
- Thermal maturity

Go or No Go

Population based - A result that becomes more reliable with sampling…
Usually pertains to averages such as

- Porosity
- Pseudo-Field Thickne
- IP

Efficiency & Profit

Learning

New information is only important if it helps you make a **Material Decision**.

Uncertainty reduction in and of itself destroys competitive advantage.

Efficient Learning has no connection to emotion… Learning to make you feel better has no real value.

Use Value of Information methods to avoid "Over Sciencing" a decision!

Key Controls on Resources & Reserves

Shale Gas Resources

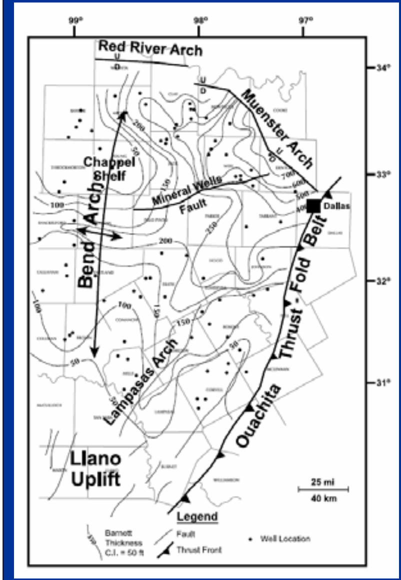
- Areal extent
- Thickness
- Structure
- Lithologic variability
- Organic richness
- Gas sorption capacity
- Porosity and Sw

Shale Gas Reserves

- Matrix permeability
- Fracture permeability
- Geomechanics
- Completion effectiveness
- Reservoir pressure,skin
- Shale maturity

Presenter's Notes: In order to estimate resources and reserves, we have to first make sure we understand what controls these numbers, and then we can collect the appropriate data and do our assessment.

With regard to resources, my view is there are a number of key controls summarized here on the left. What I'd like to do is spend a few minutes summarizing the importance of each of these.



Areal Extent and Thickness

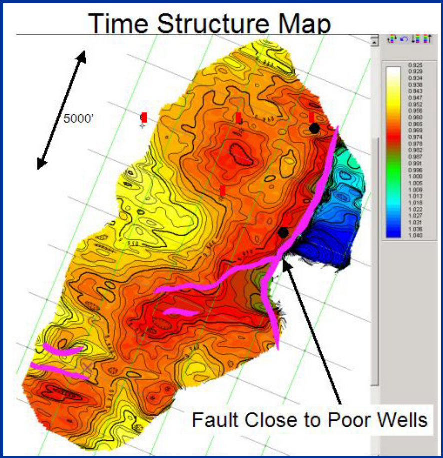
- **Laterally extensive but thickness varies**
- **Interbedded coals and sands need to be considered**

From Montgomery et al., AAPG Bulletin 89/2, 2005

Presenter's Notes: The first is areal extent and thickness of the shale interval as revealed by wellbore and seismic data. Shales tend to be laterally extensive, but their thickness can vary by hundreds of feet over short distance, especially if you traverse a fault.

There is also the potential for non-shale lithologies contributing such as coals and sands, and you want to make sure you quantify their potential as well, because whether you target them for production, of not, if they're interbedded with the shale, they're very likely to contribute to production.

Structural Geology



Impacts of Faulting

- Compartmentation
- Water conduits
- Stress/strain increase
- Horiz. well problems
- Conventional trapping

From “Barnett Shale Prospecting with 3D Processing and Analysis”, Weinman GeoScience

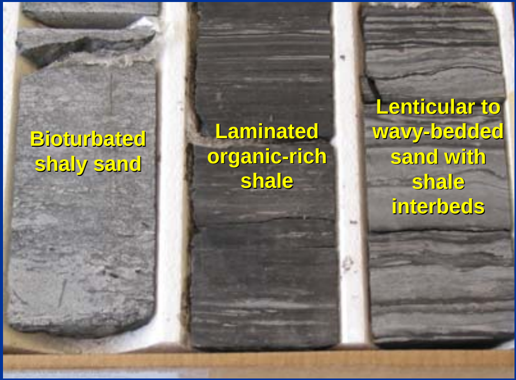
Presenter’s Notes: Faults, by and large, tend to be bad news and as a general rule should be avoided.

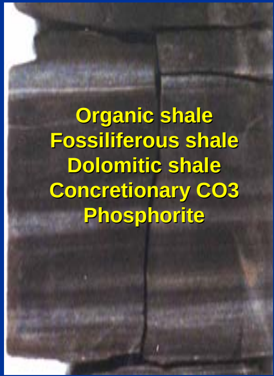
They compartmentalize the reservoir; they’re conduits for water which comes in from units above and below the shale. They have increased reservoir stresses in adjacent damage zones, making it more difficult to fracture-stimulate the reservoir.

They also present significant problems for horizontal wells that cross them, including wellbore stability and the inability to stay in the same reservoir interval.

That being said, one possible advantage of having faults is that they provide a conventional trapping mechanism to enhance gas saturations.

Lithologic Variability





Mancos Shale
From RMS/AAPG Shale Workshop, 10/07

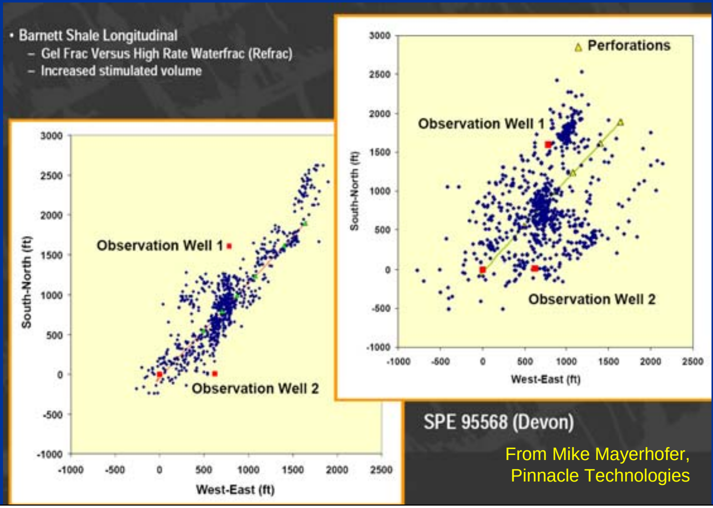
Barnett Shale
From Hickey and Henk, AAPG Bull 91/4

Presenter's Notes: Lithologic variability is important to capture from core description and petrographic work.

A key play concept in shales is the notion that you need several different facies types to optimize gas storage and production. These include

1) organic-rich shales which are the source of the gas,
2) higher-permeability layers containing silt or sand-sized grains, and
3) brittleness resulting from diagenetic cementation that leads to better "fracability" of the shale.

Completion Effectiveness

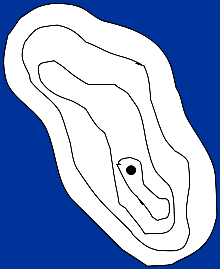


Presenter's Notes: Completion effectiveness is another critical component that affects productivity and therefore reserves.

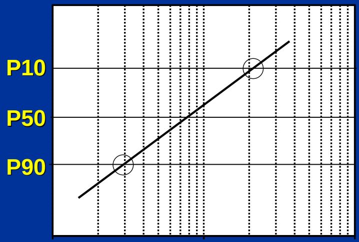
In this example, on the left side we see the microseismic pattern for a gel frac which is narrowly constrained to an area along the wellbore, whereas on the right side we see a much more expansive microseismic pattern from a high-rate water frac conducted in the same well.

The explanation here is that by pumping lower viscosity fluids at a high rate, a large volume of the reservoir can be stimulated farther away from the wellbore

Conventional Prospective Resources Approach



Prospect



Field Size Distribution

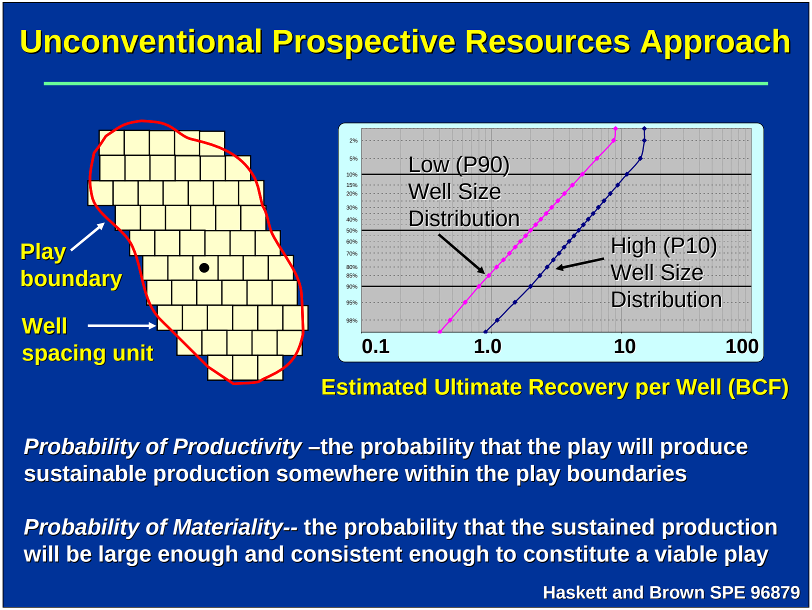
Probability of Geologic Success (Pg) **–the probability of discovering reservoirs that flow petroleum at a measurable rate.**

Probability of Economic Success (Pe)**– the probability that a given discovery will be economically viable.**

Presenter's Notes: In a conventional play, prospective resources are estimated by determining a potential field size distribution shown here on the right, and then risking this using a probability of geologic success and a probability of economic success.

The probability of geologic success is the probability of discovering reservoirs that flow petroleum at a measurable rate. It is determined by multiplying together the probability of a trap, source, reservoir, and migration path.

The probability of economic success is the probability that a given discovery will be sufficiently large to be economically viable, given the project capital costs, operating expenses, and other economic factors.



Presenter's Notes: In a unconventional play, where there is a continuous accumulation of gas, we estimate prospective resources differently. In this situation, we are virtually assured of drilling a well that produces at least some gas, so the risk is not that we'll have a dry hole. Instead, the risk is that we won't produce enough gas from enough well locations to justify developing the play.

So how do we capture this uncertainty? Well, as you can see on the left, we divide our play area into a series of well spacing units, say 80 acres in size, and then develop a set of low, best and high input parameters from which to to sample, including thickness, porosity, and gas saturation.

Using these inputs, we can then generate Estimated Ultimate Recovery values for each spacing unit and aggregate these to create an envelope of values shown in the diagram on the right. This envelope is the distribution of the recoverable resource within the area of interest. The lower values in this distribution correspond to the P90 estimate, and the higher values correspond to the P10 estimate. This envelope is equivalent to the field size distribution that you saw in the previous slide for conventional reservoirs.

We then take the values in this distribution and risk them by multiplying first by the probability of productivity and then by the probability of materiality. These two quantities, in essence, are equivalent to the Pg and Pe used for conventional reservoirs.

Input Parameters for a Probabilistic Assessment

Input Parameter	Low (P90)	Best (P50)	High (P10)
Area (acres)	40	80	160
Thickness (feet)	400	632	1000
Porosity (percent)	2	4	7
Initial gas expansion factor (rcf/mscf)	220	244	270
Matrix gas saturation (percent)	30	50	80
Gas storage capacity (scf/ton)	10	30	75
Density of shale (g/cc), rho	2.25	2.37	2.61
Recovery factor, percent	5	10	25

It's also advisable to build in key dependencies such as:

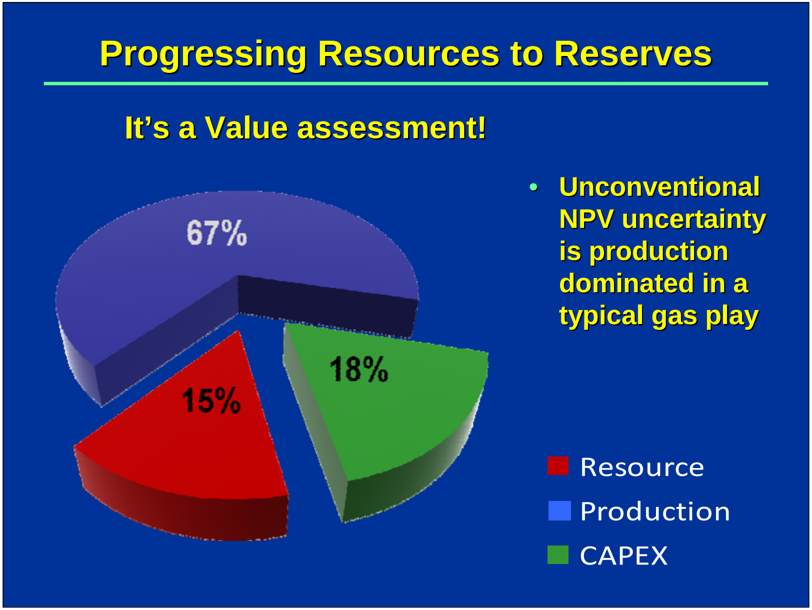
A positive correlation between matrix porosity and matrix gas saturation

A positive correlation between recovery factor and matrix gas saturation

Presenter's Notes: Now in my view, this type of probabilistic method is much better than using a deterministic technique, such as simply multiplying all the low input parameters together to get a low estimate, and all the high input parameters together to get a high estimate.

Because if you do this, the results will not be P90 and P10 values, but rather P99 and P1 values, which are essentially end-member estimates.

It's also advisable to include key dependencies in the probabilistic assessment to ensure, for example, that low values of porosity aren't matched with high values of gas saturation.

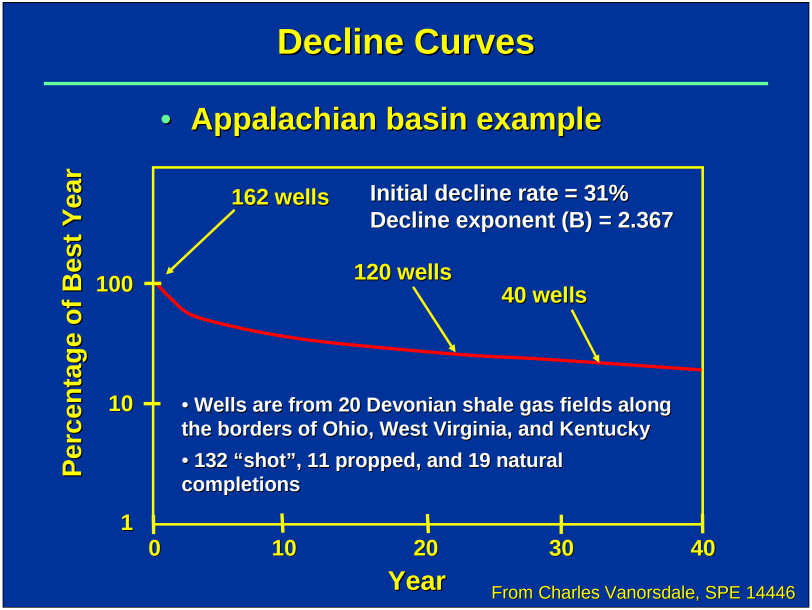


Presenter’s Notes: So assuming you have contingent resources, how do we progress these to reserves?

Well, the key tool to use in this process is some sort of pilot project designed to determine what the production rates of wells are and how much it costs to drill and complete them.

This is critical because uncertainty analysis shows that for a typical shale gas play, only about 15% of the uncertainty is related to the resource estimate.

Far and away the greatest uncertainty is whether you’re going to produce sufficient gas to have an economic project.

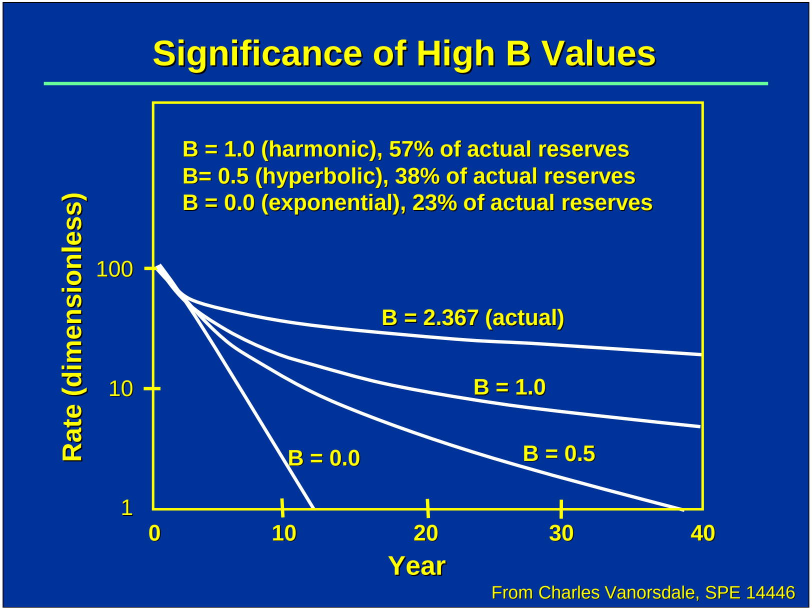


Presenter's Notes: Traditionally, reserves in shale gas reservoirs have been estimated using decline curve analysis.

The reservoirs are very tight; the wells are widely spaced; and the wells remain in transient flow for many many years.

As a result the decline exponent, or B factor as it is called, is quite high.

In the case shown here for 162 wells in Devonian gas shales in the eastern US., the B factor was 2.367.



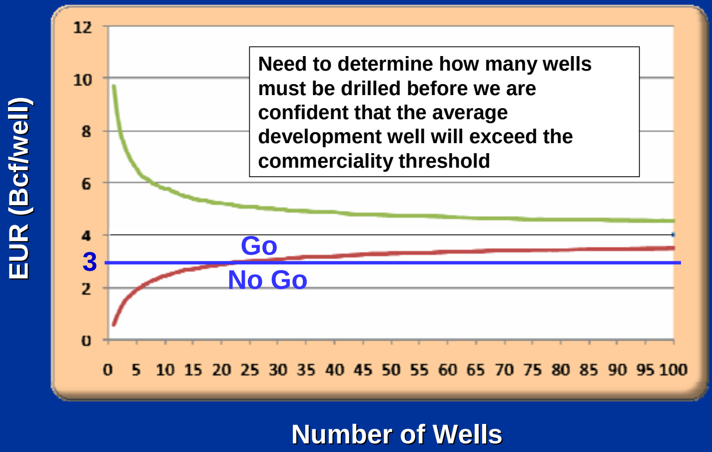
Presenter's Notes: Now the concern is, if you start drilling these wells closer together, they're not going to remain in transient flow over their entire life.

They eventually sense the nearby wells and the decline steepens.

So in the case of the Devonian wells in the eastern U.S., if the B factor drops to 1, which is harmonic decline, you'll only have 57% of the reserves you originally had. And if the B factor drops to 0, which is exponential decline, you'll only have 23% of the reserves you originally had

So some people, particularly Tom Blasingame at Texas A&M, are quite concerned that we may be overestimating reserves by using this technique to extrapolate early time data in closely spaced wells.

What's the Purpose of a Pilot Project?



From Bill Haskett, Decision Strategies

Presenter's Notes: Any pilot project essentially has two functions. The first of these is to determine whether the average well performance will exceed the commerciality threshold.

Now in the case shown here, based on some uncertainty modeling, we could drill 100 wells and conclude that the average well performance is 4 BCF plus or minus 0.5 BCF, but that's not the purpose of the pilot.

The purpose of the pilot is to determine whether the average well is likely to exceed the commerciality threshold of 3 BCF. And for that you need far fewer wells. In this case, no more than about 25 and perhaps as little as 5 to 10 wells.

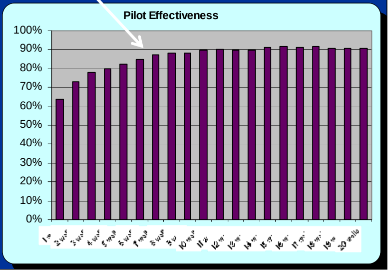
How Many Pilot Wells Do I Need?

	Pilot Good Proj. Good	Pilot Good Proj. Bad	Pilot Bad Proj. Good	Pilot Bad Proj. Bad	Pilot Effective
1 well	61%	6%	31%	3%	64%
2 wells	71%	6%	21%	2%	73%
3 wells	76%	6%	16%	2%	78%
4 wells	77%	6%	14%	3%	80%
5 wells	81%	7%	11%	2%	82%
6 wells	83%	7%	8%	2%	85%
7 wells	86%	7%	5%	1%	87%
8 wells	87%	8%	4%	1%	88%
9 wells	87%	8%	4%	1%	88%
10 wells	89%	8%	2%	1%	90%
11 wells	90%	8%	2%	1%	90%
12 wells	90%	8%	2%	0%	90%
13 wells	89%	8%	2%	0%	90%
14 wells	91%	8%	1%	0%	91%
15 wells	91%	8%	0%	0%	92%
16 wells	91%	8%	0%	0%	91%
17 wells	91%	8%	0%	0%	92%
18 wells	91%	8%	1%	0%	91%
19 wells	91%	8%	1%	0%	91%
20 wells	91%	9%	1%	0%	91%

False results!

Early wells are most critical--learning should diminish with additional drilling

Optimal Number of Wells



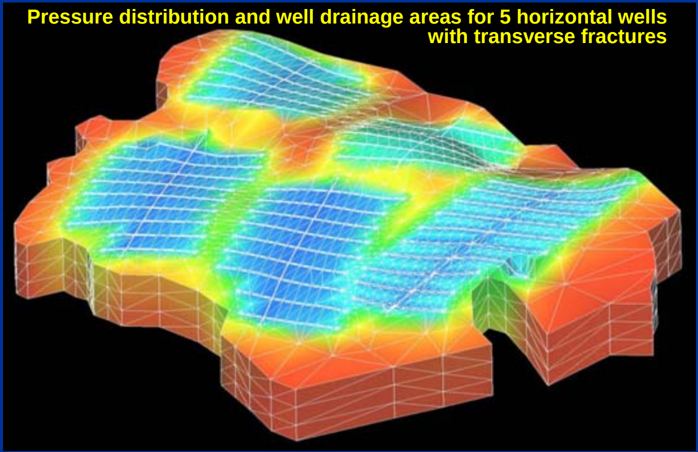
From Bill Haskett, Decision Strategies

Presenter's Notes: The second function of the pilot is to ensure that the result is a true indicator of how the entire project will perform. So again, with some uncertainty modeling, we can test how many wells we need to drill to make sure this is the case.

In the example shown here, if you drill just one well, there's a 31% chance that the pilot will give you a bad result, but that the development will be good. This is what we call a false negative. However, this chance decreases to less than 10% if you drill 6 pilot wells. Given this is the case, there's not much value in drilling more than about 6 wells in this pilot program.

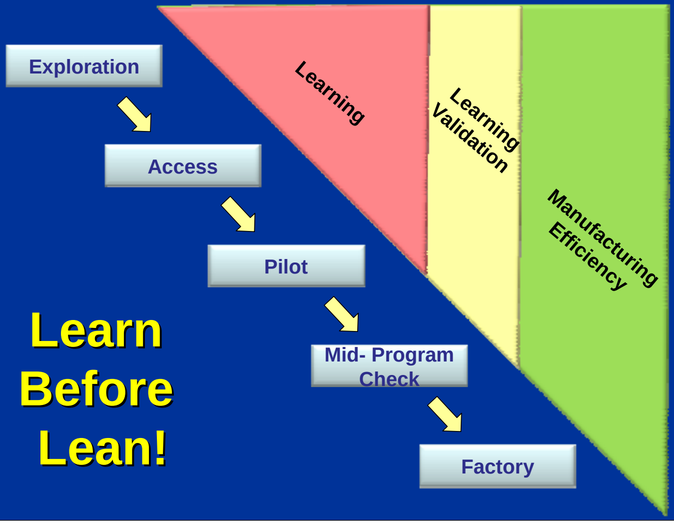
So by doing this type of uncertainty analysis, you make some estimates of the optimal number of pilot wells you'll need.

Modeling ~~Pilot~~ Well Performance



From Object Reservoir's *Resolve* Simulator

Priorities Change as the Project matures



Learn Before Lean!

Summary

- An integrated business approach should be present from day 1
- 67% of the profit uncertainty originates with the Production Profile… Not Volumetrics
- Business Pinch-point ID and management creates Competitive Advantage
- Prioritized Learning Plans and performance thresholds are critical
- Learning Efficiency translates into Manufacturing Efficiency