

# **Rethinking Unconventional Resource Assessments\***

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## **Abstract**

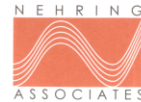
The assessments of unconventional resources in the United States made from 2009 to 2012 shaped both industry and popular perceptions of national resource potential. The perceptions that they created have proved to serve both the industry and the public poorly. The three major flaws of these assessments were (1) ignoring wide spatial variations in standardized well productivity within plays, (2) ignoring the great spatial variations in the consequent cost of production within plays, and (3) minimizing the impact of substantial changes in drilling and completion practices in reducing costs and increasing well productivity. Since 2012, several proposals have been made within the resource assessment community to create assessment approaches that better capture basic characteristics of unconventional plays and thus overcome these obvious flaws. This presentation outlines these proposals and illustrates them by means of a simplified assessment of a 10,000 square mile dry shale gas megaplay (30 TCF+ ultimate recovery). These proposals embody three general steps: (1) They begin by delineating areas within plays that have different distributions of standardized well productivity, thereby creating subplays within the play. These subplays boundaries are also correlated with spatial differences in the geologic controls that drive well productivity. (2) They calculate costs of production for each subplay based on standardized drilling and completion costs applied to the distribution of well productivity for each subplay, thereby creating a resource cost curve for each subplay. Aggregating the subplay resource costs creates a resource cost curve for the entire play. (3) Finally, they consider explicitly how major changes in drilling and completion costs (25-50% reductions) and improved recovery from better completions (25-50% increases) changes subplay and play resource cost curves, increasing both total recovery and reducing the cost of recovery. Following such an approach should make unconventional resource assessment more relevant for acreage acquisition decisions, drilling decisions (both whether and where), and projecting future production potential at different price levels.

# **RETHINKING UNCONVENTIONAL RESOURCE ASSESSMENTS**

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June 21, 2016

# THE TOPSY-TURVY WORLD OF UNCONVENTIONAL RESOURCES

- **From great expectations ....**
  - A hundred years of gas supply
  - North American oil self-sufficiency
- **To even greater disappointments**
  - Drastic reductions in drilling and declining production
  - Disappearance of market value and bankruptcies
- **From a game-changer to a replay of the 1980s and 1990s**



Presenter's notes: Unconventional resources have been described in many ways in the past ten years. Given all that has happened in the past two years, the description of a "topsy-turvy world" seems highly appropriate, if not personally painful, for most of us.

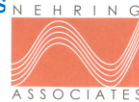
We began with high expectations, thinking in terms of a hundred years or more of gas supply and an oil self-sufficient North America.

During the past two years we have experienced even greater disappointments, including drastic reductions in drilling and declining production in what we thought were great plays, as well as an evaporation of market value and an accompanying slew of bankruptcies.

What we thought was going to be a "game changer" has turned into a depressing replay of the 1980s and 1990s.

## HOW DID THIS HAPPEN?

- “Irrational Exuberance” fueled by exaggerated and/or inadequate unconventional resource assessments
- **Primary Assessment Flaws:**
  - Massive plays were treated as homogenous entities, capable of being evaluated by play-wide averages
  - Play-wide averages substantially exaggerated
  - Assessments expressed solely as “*technically recoverable resources*” that ignored wide variations in costs
  - Invisibility of costs fostered assumption that all resources were profitable at foreseeable prices



Presenter's notes: How did this happen to us?

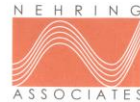
I assert that the Irrational Exuberance of the boom was fueled by inadequate, exaggerated, and, in some cases, even fabricated unconventional resource assessments.

There were four primary flaws in these assessments:

1. They treated really massive plays as homogenous entities, capable of being evaluated by play-wide averages;
2. The play-wide averages used in the assessments proved to be exaggerated;
3. Assessment results were expressed as technically recoverable resources that ignored the wide variety in costs within these plays; and
4. The resulting invisibility of costs fostered the assumption that all resources were profitable at foreseeable prices.

## KEY PROCESSES IN RETHINKING UNCONVENTIONAL RESOURCE ASSESSMENTS

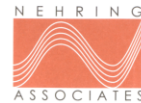
- Incorporate variability:
  - divide each play into subplays;
  - group subplays into productivity classes;
  - calculate technically recoverable resources for each group
- Estimate costs of production for each subplay group; sum subplay group cost curves to create the play cost curve
- Discern effects of innovation for both the amounts and the costs of unconventional resources



Presenter's notes: These shortcomings require a major rethinking in how we conduct unconventional resource assessments. In this presentation I suggest three key steps. The first is to explicitly incorporate variability by dividing each play into several subplays. These subplays can then be grouped into productivity classes. Technically recoverable resources can then be calculated for each group. The second is to estimate the distribution of the costs of production for each subplay group; the cost curve for the entire play can be created by aggregating the subplay group cost curves. The final step is to discern the extent of potential innovations and their implications for both the cost and amounts of play resources.

## PRESENTATION APPROACH

- Illustrate by means of a **type play** assessment
- Type Play area = 10,000 square miles (megaplay size)
- Use simplifying assumptions to concentrate on key assessment steps
- Assess as a dry shale gas play
- Approach can be both varied and elaborated



Presenter's notes: Instead of a boring discussion of methodology (although a substantial dose of methodology underlies the development of this approach), I will illustrate this approach using a type play assessment. The type play is assumed have an area of 10,000 square miles (clearly megaplay size).

Because of the severe time limits on this presentation, I will use simplifying assumptions and omit several key processes (such as the definition of subplays – which demands its own presentation) in order to concentrate on the essential steps.

These simplifications include confining the type assessment to that of a dry shale gas play.

Please note that this approach is capable of being varied to assess all types of plays with varying assumptions. It can also be elaborated substantially.

## KEY TYPE ASSESSMENT ASSUMPTIONS

<u>Productivity Group</u>	<u>Porosity</u>	<u>EUR per SL Well</u>	<u>Play Proportion</u>
<b>Good</b>	7-9%	6 BCF	05-10-15%
<b>Mediocre</b>	5-7%	3 BCF	25-30-35%
<b>Poor</b>	3-5%	1 BCF	70-60-50%



Presenter's notes: For this type assessment, I make several other basic assumptions.

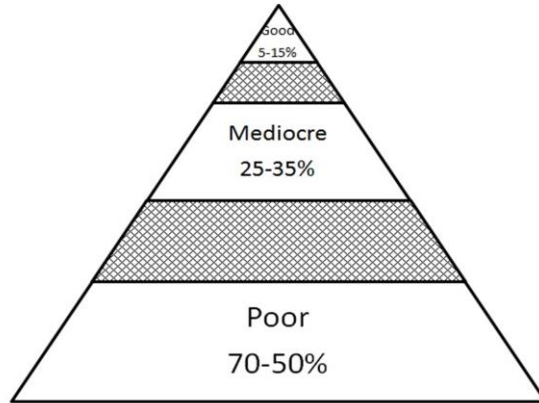
First, each subplay within the play is allocated to one of three groups, based on average productivity per well. These groups are characterized as Good, Mediocre, or Poor.

Average porosity among these three groups varies from 7-9% (Good) to 3-5% (Poor).

Average recovery per standard (5000') lateral length well varies from 6 BCF (Good) to 1 BCF (Poor). This variation reflects variability both in the ability of the reservoir to contain gas and in the recovery rate as porosity and permeability decrease. The assessment also assumes 4 laterals per section.

A key assumption is the proportion of play area assigned to each group: the Good group covers only 5-15% of the play area, the Mediocre group 25-35%, and the Poor group 70-50%.

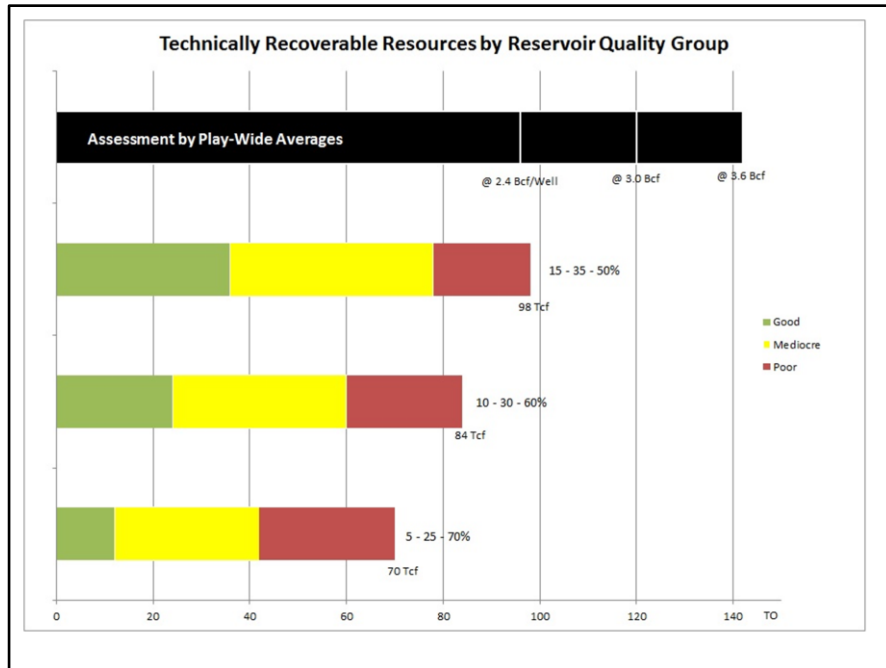
## THE INTERNAL UNCONVENTIONAL RESOURCE PYRAMID



Presenter's notes: The proportions of play area by reservoir quality groups are consistent with what I call the "Internal Unconventional Resource Pyramid".

The concept of the resource pyramid, originally developed to demonstrate differences in resource amounts among play types, seems more appropriate to illustrate differences within individual unconventional plays. Note that the proportions here are proportions of play area, not proportions of recoverable resources.

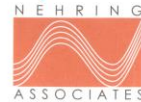
The Internal Unconventional Resource Pyramid is based on empirical generalizations developed from detailed studies of the distribution of standardized well productivity in the Barnett, Fayetteville, Haynesville, and Marcellus shale gas plays and the Middle Bakken and Three Forks tight oil plays.



Presenter's notes: This graph shows the differences in technically recoverable resources resulting from varying the proportions of play area in each productivity group. Just this one variation makes a substantial difference to the overall assessment: The high case resources are 40% more than the low case resources. The graph also illustrates the difference between assessments that differentiate by reservoir quality within the play and assessments based on play-wide averages. The latter assessment shows assessment results based on three different average play-wide values: 2.4, 3, and 3.6 BCF/well. Note that the low case of the play-wide average approach is approximately equal to the high case based on reservoir quality differences. The high case of the play-wide average assessment is double that of the low case based on reservoir quality differences.

# CALCULATING OPERATOR COST CURVES

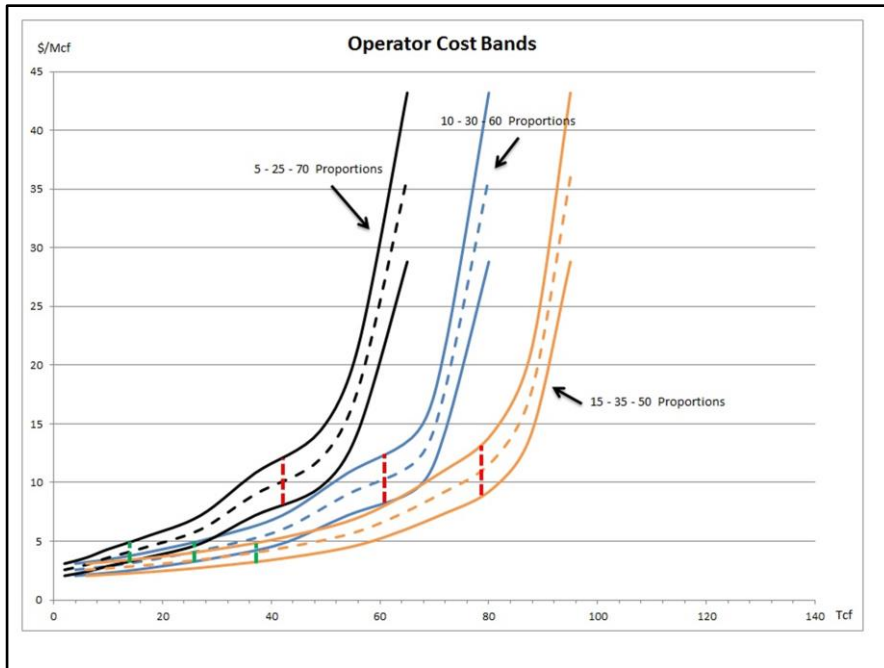
- Use \$6 million drilling and completion costs per standardized (5000' long) lateral (SL) well
- Disaggregate each productivity class into equal thirds
  - Good: 5, 6, & 7 Bcf/SL well
  - Mediocre: 2, 3, & 4 Bcf/SL well
  - Poor: 0.5, 1.0, & 1.5 Bcf/SL well
- Estimate cost/Mcf=(D&C cost/EUR per SL) X Cost factor
- Cost factor varies from 2.4 to 3.6 (incorporates lease bonus, royalty, taxes, operating expense, etc.)



Presenter's notes: For many assessment approaches, estimating technically recoverable resources is the conclusion of the process. For this approach, it is only the beginning. It is only an essential step in calculating operator cost curves.

Calculating these cost curves involves three steps:

1. Establish the standardized drilling and completion cost – In this example, I will use \$6 million per well (with a standardized lateral of 5000 feet);
2. Disaggregate each productivity class into equal thirds (in order to get a smoother cost curve); and
3. Estimate the cost for each subclass – this is a proposed shortcut instead of DCF analysis; use of the cost factor covers the variability in the several factors used in the DCF analysis.



Presenter's notes: The slide shows the calculated cost bands for the three different distributions of well productivity.

Note the green vertical lines – the boundary between good and mediocre productivity groups at roughly \$3-5/MCF, and the red vertical lines – the boundary between mediocre and poor productivity groups at roughly \$8-12/MCF

Given the variability in productivity within the play, only 20-40% of the technically recoverable resources in the three cases assessed cost \$3-5/MCF or less. 70-80% of the TRR costs \$8-12/MCF or less.

# IMPACT OF INNOVATION

- Initial example assumed 2008-2012 drilling and completion technologies and their costs
- Unconventional technologies are relatively new and thus amenable to substantial improvement
- Usual assumption is that gradual, incremental improvements occur over decades
- Recent history suggests rapid, discontinuous innovation

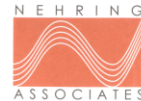


Presenter's notes: The initial assessment assumed 2008-2012 drilling and completion technologies and their costs. However, any assessment that assumes historic costs and recoveries is likely to understate substantially the potential of unconventional resources.

Many assessments do incorporate technological progress, but they assume that this progress occurs incrementally, improving only 1-2% per year. What we are seeing instead over the past three years is rapid, discontinuous improvement, both in reducing drilling and completion costs and in improving recovery.

## TWO CASES OF INNOVATION

- Case I (25/25, achieved 2013-2016)
  - Drilling and completion costs reduced 25%
  - Recovery/standardized lateral increased 25%
  - Well density increased to six laterals/section
- Case II (50/50, achievable 2017-2020)
  - Drilling and completion costs reduced 50%
  - Recovery/standardized lateral increased 50%
  - Well density increased to six laterals per section



Presenter's notes: To illustrate what such rapid change might mean for the assessment, I will consider two cases.

In the first case, I postulate reductions in drilling and completion costs of 25% per standardized lateral, 25% increases in recovery per standardized lateral, and an increase in drilling density to six laterals per section.

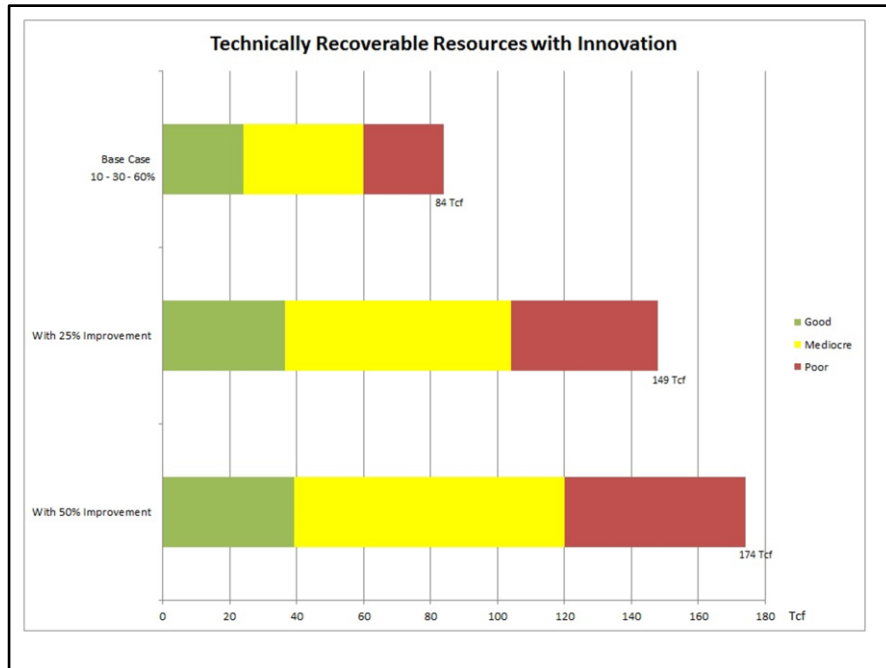
In the second case, I postulate reductions in drilling and completion costs of 50% per standardized lateral, 50% increases in recovery per standardized lateral, and an increase in drilling density to six laterals per section.

# INNOVATION IS HAPPENING

- These two cases are not arbitrary parametric estimates, but empirical generalizations of recent trends
- Reductions in drilling and completion costs
  - Extended length drilling
  - Drastic declines in drilling times
  - Adoption of pad drilling
  - Internalization of sand procurement
- Increases in recovery
  - Shorter, denser completions
  - Targeted stages (?)



Presenter's notes: These postulated changes could easily be mistaken for arbitrary parametric estimates. However, they are best understood as empirical generalizations from recent trends. Major reductions in drilling and completion costs per standardized lateral are occurring because of such practices as extended length drilling, dramatic reductions in drilling times, adoption of pad drilling, standardizing completions, and internalization of sand procurement. Increases in recovery have been occurring as operators adopt shorter, denser completions and develop approaches to targeting completion stages.

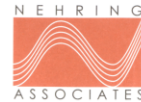


Presenter's notes: Once we incorporate the effects of innovation, assessed amounts of TRR increase substantially.

In the 25/25% improvement case, TRRs are more than 75 % higher. In the 50/50% improvement case, TRRs are nearly 110% higher. (The increase here is not as much because this case assumes that more of the good productivity group was drilled at lower recoveries with the older technologies before the improved technologies were implemented.)

## CALCULATING OPERATOR COST CURVES WITH INNOVATION

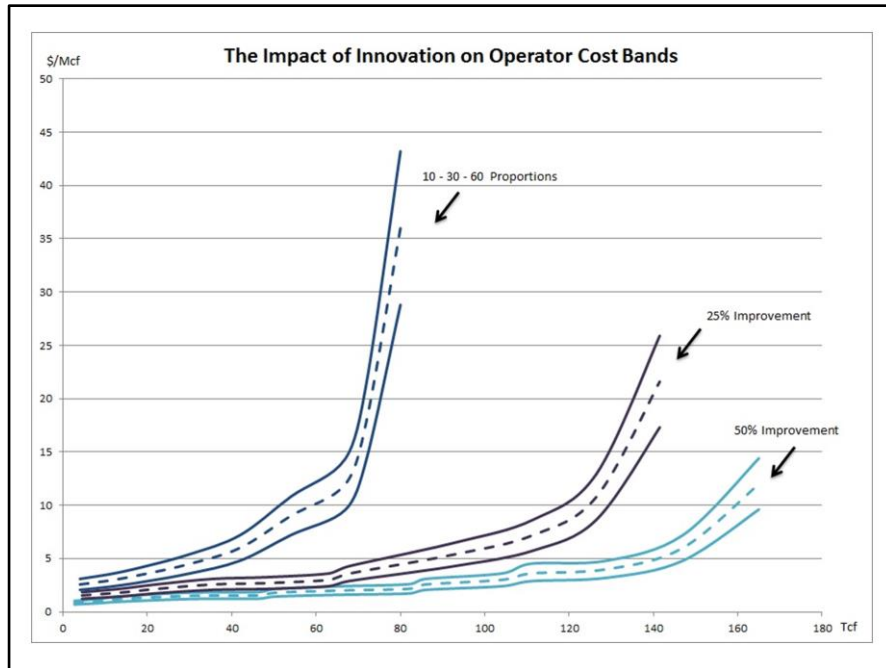
- Similar to initial approach
- Drilling and completion costs are \$4.5 million/SL in Case I, \$3.0 million/SL in case II
- Cases I and II assume that 40% of good locations already drilled at initial costs and recovery; Case II assumes an additional 30% of good locations drilled at Case I costs and recovery
- For simplicity, all mediocre and poor locations developed at costs and recovery of each case



Presenter's notes: Incorporating innovation into the cost curves shown earlier follows a similar approach as that earlier analysis.

Drilling and completion costs per standardized lateral are reduced. The innovation cases assume gradual adoption of innovation; thus substantial proportions of the good locations are drilled at prior costs and recoveries. Reducing these proportions from those assumed clearly increases the amount of low cost resources.

Since 95 to 99 % of the drilling of mediocre and poor locations are likely to occur only after innovation, for calculational simplicity, the assumption is made that all of these resources are developed at the costs and recovery of each case.



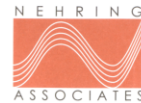
Presenter's notes: We have seen how innovation increases the total amount of technically recoverable resources. The most important impact of innovation however is that it greatly increases the amount of low cost resources. In the example shown, the amount of low cost (<\$5/MCF) resources with innovation is three to five times greater than the base case without innovation. Prior to innovation, using early technology and processes, economic resources at recent gas prices were highly constrained. With the innovation that is occurring and undergoing widespread adoption, we will see a massive expansion in low cost unconventional resources by 2020. The ultimate constraint on unconventional resources thus becomes the small number of tight oil and shale gas megaplays in North America. These great plays were created by past innovation. Recent innovation has vastly expanded the potential of these great plays. But as of now, it is difficult to see how future innovation might create new great plays of these same types.

## IMPACT OF INNOVATION

- With early technology and recent prices, economic resources were limited
- With innovation, substantial increases (2-5X) occur at both \$4 and \$10/Mcf
- Case I high probability of achievement soon; Case II probable within several years
- **Ultimate constraint on resources is the small number of oil and gas megaplays in North America**

# CONCLUSIONS

- **Rethinking assessment approaches provides a more realistic understanding of unconventional resources**
  - Emphasizes and demonstrates how important incorporating productivity variability is for assessments
  - Provides a springboard for estimating play cost curve – making the cost/resource relationship visible
  - Shows impact of innovation for both resource amounts and their costs

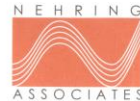


Presenter's notes: Summing up, I would assert that rethinking assessment approaches in the manner that I have just outlined provides us with a more realistic understanding of unconventional resources. It does so in three ways:

1. By emphasizing and demonstrate how important incorporating productivity variability is for unconventional assessments;
2. By providing a springboard for estimating the play cost curve, thereby making the cost/resource relationship visible; and
3. By showing the impact of innovation for both resource amounts and their costs.

## IMPLICATIONS: GAS

- **Current pace of innovation will create a massive supply of low cost gas for North America**
- Gas development will be concentrated in a few plays with the largest number of lowest cost/highest productivity locations
- Many major gas plays with excellent, but slightly higher cost opportunities could be sidelined for one or more decades
- Natural gas will undercut all new *unsubsidized* competing sources of energy for generating electricity for the next 15-20 years



Presenter's notes: The methods we use to assess resources heavily shape the ways in which we understand those resources.

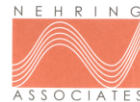
I would like to conclude by drawing out some implications of how the approach I have just outlined might affect how we understand North American unconventional gas and oil resources.

To begin with gas:

The current pace of innovation in drilling and completions will create a massive supply of low cost-gas for North America. For at least the next decade, gas development will be highly concentrated in those few plays with the largest number of the lowest cost (and generally highest productivity) locations. The corollary of this concentration is that many major gas plays with excellent, but slightly higher cost opportunities could be sidelined for one or more decades. Continued development of these low-cost opportunities means that natural gas will undercut all unsubsidized competing sources of energy for generating electricity for the next 15-20 years.

## IMPLICATIONS: OIL

- Outlook for tight oil is more uncertain – depends primarily on number of remaining high productivity locations in a few plays
- Data for evaluating tight oil resources need to be considerably improved, especially in Texas
- Even with extensive innovation, tight oil resources that are profitable at <\$50/barrel are unlikely to exceed fifteen billion barrels



Presenter's notes: The implications for oil are less obvious.

The outlook for tight oil depends heavily on the number of remaining highly productivity locations in a few plays. Unfortunately, our ability to determine the likely range of that number is hampered by the shortcomings in the information available for evaluating tight oil resources, particularly in Texas (where most tight oil resources are concentrated). The two major problems are first, the reporting of oil well production by lease, instead of by individual well. The second is the lack of differentiation among zones in basins with vertically stacked tight oil zones. Each problem seriously hobbles our capability to define subplays.

Given what we know about tight oil plays elsewhere and using these plays as analogies, I think it is safe to assert that even with extensive innovation, the amount of tight oil resources in North America that is profitable at <\$50/barrel is unlikely to exceed fifteen billion barrels.