Introduction to Unconventional Resource Booking

Rod Sidle, Fellow (Reserves Advisor)
Aucerna
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Agenda

• Background on “Unconventional”
  • How is it different from “Conventional”?  
• Resource volume booking
  • Developed volumes (SPEE Monograph 4)
  • Undeveloped volumes (SPEE Monograph 3)
  • Use of “Type Well Profiles” (SPEE Monograph 5)
• Current issues in volume booking
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Conventional v. Unconventional Reservoirs

• To make a forecast and estimate recovery, need to know......
  • **How much is there?** (reservoir storage)
  • How fast will it move? (reservoir transport)

• Conventional reservoirs:
  • Storage in porous rock, trapped under seal, above water-level or reservoir termination
  • Covers a defined area
  • Volume = Area (acres) x Stored Volume per acre
Examples of Conventional and Unconventional Reservoirs

**Conventional Reservoir:**
- Seal stops upward movement from petroleum source rock
- Structure stops lateral "spillage" of petroleum
- May be water below petroleum
- Reservoir rock transport properties ("permeability") may be high or low (i.e., "tight") but in both cases, natural transport does occur over time (to fill the trapping structure)

**Conventional Storage Estimation**

**Volumetric Equation for Oil In Place:**

\[ \text{OIP} = 7758 \times A \times h \times \phi \times S_o / B_o \]

Where:
- \( A \) = Area (acres)
- \( h \) = Net thickness (ft)
- \( \phi \) = Pore space (volume between rock grains)
- \( S_o \) = Oil saturation (fraction of pore space filled with oil)
- \( B_o \) = Factor to convert reservoir volume to surface volume
- 7758 = Units conversion factor to give surface barrels

*Can measure all variables to solve equation*
Unconventional Storage Estimation - Example

\[ \text{OIP} = 7758 \times A \times h \times \Phi \times S_o / B_o \]

Where

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- \( S_o \) = Oil saturation (fraction of pore space filled with oil)
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But before the hydraulic fracture stimulation (“fracking”), there is often very limited or no storage or transport........

Very difficult to get representative measurements of \( \Phi \) or \( S_o \) (either native or post-frac) to use in this equation

This becomes even more complex for gas....(next)

Unconventional Storage Estimation - Gas

\[ \text{GIP} = A \times h \times \left[ (43,560 \times \Phi \times S_g / B_g ) + (1.359 \times C_{gi} \times \rho_c) \right] \]

Where new terms are...

- 43,560 = Units conversion factor to give surface SCF
- \( S_g \) = Gas saturation (fraction of pore space filled with gas)
- \( B_g \) = Factor to convert reservoir volume to surface volume
- 1.356 = Units conversion factor for SCF*G/CC to MCF*Ton/Ac-Ft
- \( C_{gi} \) = Adsorbed gas content in SCF/Ton
- \( \rho_c \) = Density of carbonaceous rock (coal, shale, etc.)

So it not just recovery of gas from pore space but also recovery of gas “de-sorbed” from the formation

And that varies by the “Longmuir” isotherm and pressure
Petroleum (gas in this example) is stored in fractures (small % of total volume) or in immature solid petroleum (kerogen) or adsorbed on rock fabric grains. 
- Difficult to estimate in place volumes.

The Langmuir Isotherm shows the quantity of adsorbed gas that a saturated rock volume will contain at a given pressure.

Conventional v. Unconventional Reservoirs

- To make a forecast and estimate recovery, need to know ......
  - How much is there? (reservoir storage)
  - How fast will it move? (reservoir transport)

- Conventional reservoirs:
  - Connected pore space provides the “path” for petroleum movement
  - If pore “throats” (paths between pore openings) are smooth, large then movement of fluids (petroleum and water) will be fast, easy
  - This capacity for transport is measured as “permeability”
Permeability in Conventional v. Unconventional reservoirs

While conventional reservoirs are typically milli-darcy (0.001 Darcy) permeabilities, unconventional reservoirs will have an unstimulated permeability in the micro-darcy (0.000001 D) to nano-darcy (0.000000001 D) range.

That's why fracture stimulation is needed to create a transport path (as well as storage).

Transport in an Unconventional reservoir (+ flow regimes)

- Figure shows the map (aerial) view of a multi-fractured, horizontal well in an Unconventional reservoir
- Flow starts with fluid nearby frac moving linearly into frac then into the wellbore
- Eventually the drainage area extends outside of near-frac region to an elliptical pattern
- Then these “ellipses” of drainage converge (fracture interference) and the area outside the SRV begins to be drained (late linear)
- Reality complication: frac spacing and size varies so the drainage and interference are NOT uniform

Where → represents flow of oil in the reservoir/wellbore
Example of Unconventional well flow regimes

Colors represent production rates at different bottom-hole pressures.

Flow Regime Theory
from SPEE Monograph 4, describing multi-fractured horizontal wells

- Transient Linear Flow
  (until fracture interference, b=2)

- Boundary Influenced Flow
  (BDF of Stimulated Reservoir Volume b < 1, Linear beyond SRV b=2)

- Boundary Dominated Flow (b < 1)

Compare Transport in Conventional / Unconventional Reservoirs

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Conventional reservoir</th>
<th>Unconventional reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rock permeability</td>
<td>May vary but consistently higher</td>
<td>Highly variable but consistently very low</td>
</tr>
<tr>
<td>Well completions</td>
<td>Tap natural storage, transport</td>
<td>Create primary storage, transport</td>
</tr>
<tr>
<td>Fluid transport</td>
<td>Vertical wells - one direction (radial)</td>
<td>Horiz, frac’d wells - changes with flow regime</td>
</tr>
<tr>
<td>Flow regimes over life</td>
<td>Short transient, mainly BDF over life</td>
<td>Long transient, changing, may never get to BDF</td>
</tr>
<tr>
<td>Production forecasting predictability</td>
<td>PUD - Good when inflow parameters known; PDP - very good when producing in BDF (using DCA)</td>
<td>Very challenging given high variability in rock characteristics, completions and flow regimes; must use PDP DCA and statistics for PUD</td>
</tr>
</tbody>
</table>
Now to booking volumes........

We have finished with the foothills, the mountains are ahead........

Challenges of Reserves in Unconventional Reservoirs

Applicability in **Conventional** reservoirs is tied to field maturity

- Analogy (from another field)
- Volumetric
- Material balance
- Performance

- Reservoir simulation and (volumetric) probabilistic methods can support other methods at any stage of maturity

*But for Unconventional Reservoirs, some of these methods won’t work.....*
Challenges of Reserves in Unconventional Reservoirs

Applicability in Conventional reservoirs is tied to field maturity

- Analogy (from another field)
- Volumetric
- Material balance
- Performance

- Reservoir simulation and (volumetric) probabilistic methods can support other methods at any stage of maturity

*For Unconventional Reservoirs, only Performance of producing wells (DCA) and analogy with in-field wells, often using empirical statistical/probabilistic methods, are primary estimation approaches.*

Unconventional Resource Volume Estimation – Developed 1

- Start with mature producing wells to get EUR estimate and typical decline parameters.

- In many cases, the well life production function is modeled using several periods, each with different decline parameters.
Unconventional Resource Volume Estimation – Developed 2

• Start with mature producing wells to get EUR estimate and typical decline parameters.

Probit Plot* for EUR variation

Common measure of variability: P10/P90 Ratio (i.e., slope of the line)

* Plot for a Log-Normal Distribution shown

• **Purpose** - Assess current methods to forecast performance of wells in unconventional reservoirs given different reservoir types, different completions, and different well maturities.

**Chapters**
1. Introduction
2. Def’n of Unconventional Reservoirs (UCR)
3. Reservoir Characterization Aspects of Estimating Developed Reserves in UCR’s
4. Drilling, Completions, and Operational Aspects of Estimating Developed Reserves in UCR’s
5. Classical Arps’ Decline Curve Analysis (DCA)
6. Fluid Flow Theory & Alternative Decline Curve Methods
7. Model-Based Well Performance Analysis & Forecasting
8. Discretized (Numerical) Models
9. Quantifying Uncertainty in the Estimation of Developed Reserves
10. Example Problems

**Discussion on:**
- Arps
- Linear Flow
- Stretched Exponential (SEDM)
- Duong
- RTA (including Blasingame)
- Numerical (simulation) models
Summary - Developed Reserve Estimation

- **Classification** ("Reserves") is easy for producing wells.
- **Categorization** (P1/P2/P3) comes from uncertainty in forecast method (Multi-segment Arps hyperbolic, Duong, SEDM, etc.) and assumed decline parameters.
- For "mature" wells (i.e., with enough historical data to fit a well-specific forecast), reserves are individually estimated.
- For "immature" but producing wells (i.e., recent production starts), typical well production profiles are used (as for Undeveloped).
  - ISSUE: Should the forecast be adjusted (shifted up/down) for actual peak production rate?

**WARNING:** This has been a highly over-simplified summary of the challenge of forecast unconventional producing wells. It’s not that easy!
Undeveloped Reserve Evaluation in Shale Reservoirs: Understanding SPEE Monograph 3 and other options

Presentation Outline

• Review some key requirements for Undeveloped Reserves in Unconventional Reservoirs
  o Identify formation, fluid characteristics within resource play area
  o Check variability of Developed Well EURs per Monograph 3 requirements

• If requirements not (yet) met, consider a Deterministic approach
  o Example - Reference: SPE 107659 (Attanasi et al)

• If requirements met, use a Statistical approach
  o Example - Reference: SPEE Monograph 3
Resource Play Undrilled location EUR: Pre-requisites

- A regionally pervasive potentially productive formation has been identified.

- Productivity has been tested and validated in many multiples of wells, each with enough production to estimate well EUR.

- Typical of resource plays, the productivity is highly variable, in fact, some drilled locations may not be commercially productive.

Undeveloped Unconventional Reserve/Resource Estimation

- Begins with understanding the reservoir:
  - ✔ Formation characteristics
  - ✔ Fluid characteristics

SPEE Monograph 4* goes into greater detail on all the geological factors that can vary within and among resource plays.

In this example, the depositional system shows significant variations that relate to “sweet spots” – so location does matter.


Fig. 3.5. Haynesville (HVL) shale depositional system showing the organic-rich shale basin (green-yellow) rimmed by islands (white), carbonate platforms (blue), strandplain clastics (yellow), fluvial sediments (light orange), and prodelta deposits (brown). Red circle delineates the sweet spot of better performing wells. (Modified from Hammes et al. 2011)
**Undeveloped Unconventional Reserve/Resource Estimation**

- **Begins with understanding the reservoir:**
  - Formation characteristics
  - Fluid characteristics

Again SPEE Monograph 4* shows other variations—this time tied to fluid composition.

Such variations need to be understood to validate the analogy intended in Undeveloped Well forecasting.


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**Resource Play Characteristics per SPEE Monograph 3**

**Tier 1** *(Required for application of Monograph 3 method)*

1. Exhibits a **repeatable statistical distribution** of EURs.
2. Offset well performance is **not** a reliable predictor of undeveloped location performance.
3. Continuous hydrocarbon system which is regional in extent.
4. Free hydrocarbons (non-sorbed) are not held in place by hydrodynamics.

**Tier 2** *(Not required but typical characteristics)*

5. Requires extensive stimulation to produce at economic rates.
6. Produces little in-situ water (except for CBM and Tight Oil Reservoirs).
7. Does not exhibit an obvious seal or trap.
8. Low matrix permeability (<0.1 mD).
“Repeatable Statistical Distribution”

Mono 3 - Minimum Sample Size to define distribution within 10% (or less) of mean at 90% confidence interval

Table 2.1 Recommended Minimum Sample Size

<table>
<thead>
<tr>
<th>P_{10}/P_{90} Ratio</th>
<th>Recommended Sample Size</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>15</td>
<td>Ratio not likely to be seen</td>
</tr>
<tr>
<td>3</td>
<td>35</td>
<td>Common Ratio</td>
</tr>
<tr>
<td>4</td>
<td>60</td>
<td>Common Ratio</td>
</tr>
<tr>
<td>5</td>
<td>75</td>
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<td>6</td>
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<td>8</td>
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<td>Common Ratio</td>
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<tr>
<td>10</td>
<td>170</td>
<td>Possible data quality / analogy issues</td>
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<tr>
<td>15</td>
<td>290</td>
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<td>20</td>
<td>420</td>
<td>Possible data quality / analogy issues</td>
</tr>
<tr>
<td>30</td>
<td>670</td>
<td>Possible data quality / analogy issues</td>
</tr>
</tbody>
</table>
Monograph 3 Application Concepts

Fig. 3.1 – Typical Resource Play Diagram

Monograph 3 – Defining “Proved Area” (a)
Monograph 3 – Defining “Proved Area” (b)

Fig. 3.20 - Example Problem 1 - Overlapping Clipped Polygons

Monograph 3 – Defining “Proved Area” (c)

Fig. 3.21 - Example Problem 2 - Final Proved Area
Impact of Aggregation on Proved Reserves

- All wells are represented by the same distribution with mean = 1.5 BCF
- Proved (P90) per well varies with program size, e.g.
  - 1 well, 0.35 BCF
  - 30 wells, 1.2 BCF (average per well)
  - 100 wells, 1.3 BCF (average per well)

Summary - Undeveloped Reserve Estimation

- **Categorization** ties primarily to two factors:
  - “Proved Area” (area with demonstrated statistical validity) based on Monograph 3 testing criteria (or if not, Probable or Possible dependent on level of uncertainty beyond “Proved”)
  - Probability level of the statistical variation, i.e., P90/P50/P10, for the size (number of wells) of the drilling program (typically annual program).
Summary - Undeveloped Reserve Estimation

• Classification within a resource play discovered area (assuming all other commerciality requirements are satisfied) will often be dependent on timing of the “project” development – within five years of booking or not?
  • If within five years, volumes are reserves.
  • If beyond five years, volumes are contingent resources.
  • To the US SEC, an single unconventional well is a project.

To book Undeveloped, you need a production profile

• The production profile for Undeveloped Unconventional resource volumes is often the “Typical Well Production Profile” or Type Well.
• Proper construction and use of the Type Well has been an hotly debated and mis-understood process, sometimes leading to poor investment decisions and inaccurate reserve estimates if incorrectly done.
• After addressing industry needs with Monographs 3 and 4, SPEE is now working on Type Well guidance....

Monograph 5: A Practical Guide to Type Well Profiles
Type Well Production Profiles – It’s not just the average...

• Given the natural variability in Unconventional Reservoir well performance, the “typical” well profile is often best expressed by a range of forecasts.
• Thus the TWP analysis needs to provide forecasts for the p90/p50/p10 outcomes to give the full range.

Fig. 9.27 Example of TWP for Haynesville wells


What is the Mono 5 Committee trying to accomplish?

Establish Practical Industry Guidance

• Adherence to Fluid Flow Principles
• Methods of Construction
  • Public Data vs Proprietary Data
  • Fit for Purpose
  • Analogy definition
  • Survivor Bias
  • Bin Selection
  • Scaling
• Validation of Results
• Communication of Uncertainty

✓ Physics
✓ Analogy
✓ Statistics
TWP Considerations include...

- Survivor Bias - Tendency to bias towards the longest surviving wells when averaging production

- Binning - Grouping wells into analogous categories so that a TWP is meaningful and predictive, while keeping the number of samples per bin statistically meaningful

- Scaling – Adjusting well performance data to represent the result as if other than actual conditions existed (e.g., horizontal length, frac job size, frac spacing, etc.). Done to improve Bin size for a given Statistical Population.

The End – Thanks for your interest and attention!