WOLF OF WALL STREET- USING RESERVOIR ENGINEERING INSIGHT TO GUIDE OIL AND GAS INVESTMENT DECISIONS

David M. Anderson, Director
Anderson Thompson – Who are we?

Anderson Thompson is a team of reservoir engineers, geoscientists, and hydraulic-fracturing specialists, whose mission is to support your efforts to improve the performance and profitability of your unconventional assets through practical and innovative field-development optimization

- We partner with oil and gas operators and investors ranging from start-ups to multinationals
- Our team has world-class expertise in unconventional reservoir characterization and production forecasting
- We have broad international basin experience with specialization in the Permian, Eagle Ford, Bakken, Marcellus, and Montney plays
Objectives of this Presentation-

• Learn how to critically evaluate investor and technical presentations and identify the most common fallacies

• See through the “noise” and make better sense of publically available oil and gas data and market research

• Learn how to find hidden opportunities and avoid costly pitfalls when evaluating assets and deciding where to invest

• Understand how reservoir value translates into market value (or how it sometimes doesn’t)
Topics of Discussion – Reservoir Engineering Insights

• Robbing PDP to pay PUD
  ➢ Bakken/Three Forks Example

• If you torture data enough it will confess to anything
  ➢ The peak rate fallacy
  ➢ False causality
  ➢ Mean or median?

• Unrealized potential- the diamond in the rough
  ➢ Identifying upside in assets with existing production
  ➢ Identifying good investment opportunities
Reservoir Engineering
Insight #1-
Robbing PDP to pay PUD
Production Forecast – based on decline curve

Mathistad 2-35H Middle Bakken Well

Is this a realistic production forecast?

40-year EUR = 425 Mbbl
constant ‘b-value’ of 2.07

Cross Section View of Mathistad Wells

Mathistad 2-35H MB
Completed June 2009

Mathistad 1-35H TFS
FPDate 7-4-08

Plan View of Mathistad Wells

Bakken and Three Forks wells have unbounded lateral drainage

Mathistad 2-35MB Updated Production
Decline Curve Analysis
b-value = 2.07
40-year EUR = 425 Mbbl
Decline Curves 101

The Hyperbolic Decline Curve

\[ q = \frac{q_i}{(1 + bD_i t)^{1/b}} \]

- **Initial production rate**
- **Hyperbolic exponent**
- **Initial decline rate**

<table>
<thead>
<tr>
<th>b value</th>
<th>Reservoir Drive Mechanism</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 (exponential)</td>
<td>Single phase liquid expansion (oil above bubble point), single phase gas expansion at high pressure, water or gas breakthrough in an oil well</td>
</tr>
<tr>
<td>0.1 – 0.4</td>
<td>Solution gas drive</td>
</tr>
<tr>
<td>0.4 – 0.5</td>
<td>Single phase gas expansion</td>
</tr>
<tr>
<td>0.5</td>
<td>Effective edge water drive</td>
</tr>
<tr>
<td>0.5 – 1</td>
<td>Layered reservoirs</td>
</tr>
<tr>
<td>1 – 1.5</td>
<td>Transitional flow in multi-stage hz wells frac’d reservoirs</td>
</tr>
<tr>
<td>2</td>
<td>Linear flow</td>
</tr>
</tbody>
</table>
Forecast Comparison - DCA vs. Model Based

Decline Curve Analysis
b-value = 2.07
40-year EUR = 425 Mbbl

1320 ft well spacing case
40-year EUR = 412 Mbbl

Model supports DCA assuming 320 acre drainage
Operator’s Drilling Program

First Full Pattern 160-Acre Development Pilot

- 14 wells drilled in one 1280 (Mar 2013-Mar 2014)
- 4 MB, 3 TF1, 4 TF2, 3 TF3
- 660’ inter-well spacing between same-zone wells

Reservoir Models - Base Case vs. Infill

320 acre drainage area per well

1320 ft

160 acre drainage area per well

660 ft
Production Forecasts- Base Case vs. Infill
Production Forecasts- Base Case vs. Infill

Decline Curve Analysis
b-value = 2.07
40-year EUR = 425 Mbbl
Production Forecasts- Base Case vs. Infill

Decline Curve Analysis
b-value = 2.07
40-year EUR = 425 Mbbl

1320 ft well spacing case
40-year EUR = 412 Mbbl
Production Forecasts - Base Case vs. Infill

Decline Curve Analysis
b-value = 2.07
40-year EUR = 425 Mbbl

1320 ft well spacing case
40-year EUR = 412 Mbbl

660 ft well spacing case
40-year EUR = 238 Mbbl
Production Forecasts- Base Case vs. Infill

660 ft well spacing  
160 acre case

1320 ft well spacing  
320 acre case
Robbing PDP to pay PUD - Summary

- Production decline changes when infill wells are drilled!
- DCA-based type curves are usually not adjusted to account for the impact of infill drilling programs
- The optimum drilling density in a field development scenario often requires “robbing PDP to pay PUD!”

![Graph showing NPV and EUR/Well vs Wells/DSU]

- **NPV** ($MM)
- **EUR/Well** (Mbbl)
- **Wells/DSU**
- EUR/well begins to drop due to infill drilling
- Optimum drilling density for NPV
Reservoir Engineering Insight #2-
If you torture data enough, it will confess to anything
The Fallacy of the 30 day IP (or peak rate)

1 Calendar Month Np vs 5 Year Np

All producing oil wells in Alberta since 1987-
- Wells with high initial productivity often do not perform well in the long-term (and vice-versa)

Why??
Initial production rates are DOMINATED by operations during the first few weeks- long term reservoir capability is usually MASKED
The Fallacy of the 30 day IP (or peak rate)

3 Calendar Month Np vs 5 Year Np

Correlation is better for 90 day (3 month) rate but still poor $R^2<0.5$
Calendar Time IP or Producing Time IP?

Calendar Time IP is biased towards wells with low downtime and/or high drawdown

Producing Time IP is biased towards wells with high downtime and/or low drawdown

Courtesy of Bertrand Groulx
Correlating Early Production Indicators to EUR

### 4 Play Analysis of the Correlation of Production Measures to EUR using VISAGE

<table>
<thead>
<tr>
<th>VISAGE</th>
<th>Montney (Gas)</th>
<th>Cardium (Oil)</th>
<th>Viking (Oil)</th>
<th>Bakken (Oil)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Data Set 1</td>
<td>Data Set 2</td>
<td>Data Set 1</td>
<td>Data Set 2</td>
</tr>
<tr>
<td></td>
<td>Correlation %</td>
<td>Well Count</td>
<td>Correlation %</td>
<td>Well Count</td>
</tr>
<tr>
<td>PD Rate (month 1)</td>
<td>10.6</td>
<td>585</td>
<td>18.9</td>
<td>227</td>
</tr>
<tr>
<td>PD Rate (month 1-2)</td>
<td>21.0</td>
<td>584</td>
<td>29.9</td>
<td>226</td>
</tr>
<tr>
<td>PD Rate (month 1-3)</td>
<td>31.2</td>
<td>583</td>
<td>36.7</td>
<td>225</td>
</tr>
<tr>
<td>Peak</td>
<td>60.0</td>
<td>585</td>
<td>56.2</td>
<td>227</td>
</tr>
<tr>
<td>IP30</td>
<td>32.6</td>
<td>585</td>
<td>39.3</td>
<td>227</td>
</tr>
<tr>
<td>IP60</td>
<td>42.7</td>
<td>585</td>
<td>45.2</td>
<td>227</td>
</tr>
<tr>
<td>IP90</td>
<td>49.2</td>
<td>585</td>
<td>49.9</td>
<td>227</td>
</tr>
<tr>
<td>IP180</td>
<td>60.8</td>
<td>576</td>
<td>62.0</td>
<td>227</td>
</tr>
<tr>
<td>IP365</td>
<td>72.4</td>
<td>576</td>
<td>74.9</td>
<td>227</td>
</tr>
<tr>
<td>3 Month Cum</td>
<td>23.2</td>
<td>585</td>
<td>19.4</td>
<td>227</td>
</tr>
<tr>
<td>6 Month Cum</td>
<td>49.3</td>
<td>585</td>
<td>45.1</td>
<td>227</td>
</tr>
<tr>
<td>12 Month Cum</td>
<td>67.1</td>
<td>523</td>
<td>67.0</td>
<td>227</td>
</tr>
<tr>
<td>18 Month Cum</td>
<td>75.4</td>
<td>418</td>
<td>76.1</td>
<td>227</td>
</tr>
<tr>
<td>24 Month Cum</td>
<td>79.7</td>
<td>377</td>
<td>81.6</td>
<td>227</td>
</tr>
<tr>
<td>30 Month Cum</td>
<td>83.5</td>
<td>367</td>
<td>85.1</td>
<td>227</td>
</tr>
<tr>
<td>36 Month Cum</td>
<td>87.5</td>
<td>327</td>
<td>87.5</td>
<td>227</td>
</tr>
<tr>
<td>3 Month Cum</td>
<td>16.4</td>
<td>585</td>
<td>8.9</td>
<td>227</td>
</tr>
<tr>
<td>6 Month Cum</td>
<td>40.3</td>
<td>585</td>
<td>30.5</td>
<td>227</td>
</tr>
<tr>
<td>12 Month Cum</td>
<td>59.5</td>
<td>523</td>
<td>56.2</td>
<td>227</td>
</tr>
<tr>
<td>18 Month Cum</td>
<td>71.5</td>
<td>474</td>
<td>70.5</td>
<td>227</td>
</tr>
<tr>
<td>24 Month Cum</td>
<td>77.5</td>
<td>377</td>
<td>78.4</td>
<td>227</td>
</tr>
<tr>
<td>30 Month Cum</td>
<td>82.0</td>
<td>367</td>
<td>83.5</td>
<td>227</td>
</tr>
<tr>
<td>36 Month Cum</td>
<td>86.4</td>
<td>327</td>
<td>86.4</td>
<td>227</td>
</tr>
</tbody>
</table>

**Legend**
- Green = Correlation between 70% and 100%
- Yellow = Correlation between 50% and 70%
- Red = Correlation between 30% and 50%
- Grey = Correlation between 0% and 50%

**Data Set 1** = wells with >80% correlation on Modified Duong fits for both “a” and “m” and >6 months production after peak

**Data Set 2** = subset of Data Set 1 where all wells have >=36 months production

Note: Sample sets include only horizontal wells.

EUR calculation based on 240 month forecast using Modified Duong auto-forecast up to boundary dominated flow BDF, then transitioning to Arps for remainder of forecast.

Gas wells (Montney) used 60 months to BDF and a b value of 0.5 for Arps

Oil wells (Cardium, Viking and Bakken) used 48 months to BDF and a b value of 0.5 for Arps

Courtesy of Bertrand Groulx
Example of Peak Rate Fallacy

Which is the better well?

Well 1
Well 2
Use Rate Transient Analysis to Reveal the Truth!

Linear Flow Specialized Plot Analysis

Function of rates AND flowing pressures
Flatter = better
Well 2 is the better well!
RTA (reservoir model) Forecasts

Production update- confirms early predictions
False Causality

• Belief that correlation proves causation

• Examples-
  ➢ Sleeping with one’s shoes on is strongly correlated with waking up with a headache. Therefore sleeping with shoes on causes headaches
  ➢ As ice cream sales increase, the rate of drowning deaths increases sharply. Therefore, ice cream consumption causes drowning
False Causality in Oil and Gas Data

- Proppant “X” is correlated with better well performance in the Eagle Ford. Therefore using proppant X will result in better well performance.

![Bar chart showing correlation between average peak rate and proppant type.

- Reservoir engineering insight- Proppant “X” was used by a single operator with the best land position in the EF; Operator also known for flowing back wells unchoked (to maximize 30-90 day production).
False Causality in Oil and Gas Data

• Frac fluid additive “X” is correlated to better well performance. Therefore using additive “X” will result in better well performance

• Reservoir engineering insight- Frac fluid additive “X” was only used by in wells stimulated by oilfield service company “Y” which has a larger fleet, more horsepower and tends to pump larger jobs
What Really Drives Well Performance?

Operations
- Open vs choked flow
- Shut-ins
- Flowing pressure profile
- Artificial lift
- Separator pressure/ temp

Reservoir/Fluid
- Reservoir pressure
- Net pay
- Porosity
- $S_w$
- Young’s modulus
- Poisson’s ratio
- Natural fractures
- Stress profile
- Permeability
- Fluid compressibility
- Pore compressibility
- Fluid viscosity
- Gas solubility
- Gas gravity
- Oil API gravity
- Capillary pressure

Completion/Wellbore
- Lateral length
- Landing depth
- Tubing/casing size/depth
- Number of entry points
- Missed entry points
- Completion type
- Proppant volume
- Proppant type
- Fluid volume
- Fluid type
- Treatment schedule
- Well spacing

Just one of many variables that influence well performance
Eagle Ford Well Performance – Sensitivity Analysis

0.0001 < k < 0.01 md

1 year Np (Mstb)

Dominant - permeability, thickness, fracture length, number of stages

Second Order - fracture conductivity (related to proppant type)
False Causality

• Beware of “sweeping conclusions of causality” that are based on two dimensional correlations

• The vast majority of well performance variance results from differences in the rock and reservoir fluids

• Reservoir engineering insight will find the true underlying performance drivers that are specific to the play of interest
Statistics 101 - Mean or Median?

Cumulative Distribution of EURs in Bone Spring, Lea County

Median (P50) EUR = 150 Mstb
Mean EUR = 205 Mstb
Mean vs Median Type Well Curves

Type Wells – Tight Gas Field, Wyoming

Mean (Average)
P50
Mean vs Median Type Well Curves- Impact on EUR

Type Wells – Tight Gas Field, Wyoming

- Average – 7.5 bcf
- P50 – 6 bcf

Type Well based on average is 25% better
Mean or Median?

- Median is a better indicator of how a new well is likely to perform
- Mean is the average - in a log normal distribution, mean is higher than the median
- E&Ps that use type curves based on mean are likely overstating the value of undrilled acreage, especially for small drilling programs
- Type well curves created using limited statistical samples are unreliable
Reservoir Engineering Insight #3-
Unrealized potential- the diamond in the rough
Using Reservoir Insights to Find Opportunity

• How can reservoir engineering insight be used to identify underperforming assets?

• How closely can value created in the reservoir be correlated to shareholder and market value?
Example 1 - Insufficient Pipeline Capacity

- Drop in production rate
- Increase in decline rate
- No loss in productivity!
- Model – OGIP = 24 bcf
- Recoverable Gas – 18 bcf

Increasing back pressure due to reduced pipeline capacity

Rectangular Reservoir Model
Pressure History Match

<table>
<thead>
<tr>
<th>Legend</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure</td>
</tr>
<tr>
<td>Gas</td>
</tr>
<tr>
<td>Synthetic Pressure</td>
</tr>
</tbody>
</table>

Simulated and measured bhp (psia)

Gas Rate (MMscfd)

Time, days

Andersen Thompson
Example 1- Do Nothing or Remove Back Pressure

Based on current conditions:

EUR = 3 bcf

EUR = 18 bcf if back pressure is removed!
Example 2 - Productivity Loss

Which well is underperforming?

Gas Well 1

Gas Well 2
The Power of the Diagnostic RTA Plot

Gas Well 1-
Continuous linear flow response – healthy well

Gas Well 2-
Discontinuity, sudden loss of productivity after 2 months on-stream
Identifying Common Well Performance Issues

<table>
<thead>
<tr>
<th>Issues</th>
<th>Surface</th>
<th>Wellbore</th>
<th>Completion / Reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low pump efficiency</td>
<td>Mechanical blockage</td>
<td>Frac face skin</td>
<td></td>
</tr>
<tr>
<td>Insufficient compression</td>
<td>(Unmilled ball seats, parted casing, proppant bridge etc)</td>
<td>Low frac conductivity</td>
<td></td>
</tr>
<tr>
<td>Insufficient pipeline</td>
<td>Liquid loading</td>
<td>Fines migration</td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>Buildup of precipitates</td>
<td>Stress dependent flow capacity</td>
<td></td>
</tr>
<tr>
<td>Chokes / restrictions</td>
<td>Underperforming artificial lift</td>
<td>Phase trapping</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Interference</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Water influx</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Symptoms</td>
<td>Drop in rate</td>
<td>Inconsistent flowing pressure response</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Increase in decline rate</td>
<td>High measured bhp</td>
<td></td>
</tr>
<tr>
<td>How to diagnose it</td>
<td>Look at production data</td>
<td>Noisy production data</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Use RTA / modeling</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Pipeline modeling</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Resolution</td>
<td>Easy</td>
<td>Use RTA / modeling</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low risk</td>
<td>Downhole camera</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Moderate Difficulty</td>
<td>Measure bhp</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Medium risk</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Difficult</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>High risk</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Anderson Thompson
Finding Upside in Production

• Choose an asset where bulk of the wells are underperforming against the reservoir due to surface or wellbore issues. Find-
  - Potential to implement field wide artificial lift or compression
  - Potential to lower tubing in vertical gas wells
  - Potential for optimizing surface facilities (line looping)
Translating Reservoir Value into Market Value

• Who are the most successful oil companies?
• Why are they successful?
• How are value and success measured?
  ➢ IP - 30 day or 365 day?
  ➢ Time to payout and cash flow
  ➢ NPV and IRR
  ➢ Repeatability and scalability with low risk

*Optimized reservoir management isn’t always rewarded in the market, but it will almost always provide the best NPV for the asset*
### Strategies that Oil Companies Use

<table>
<thead>
<tr>
<th>Short Term</th>
<th>Long Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Maximize IP</td>
<td>- Maximize ultimate recovery of the entire asset</td>
</tr>
<tr>
<td>- Minimize D&amp;C cost</td>
<td>- Focus on integration of disciplines</td>
</tr>
<tr>
<td>- Find the sweet spot</td>
<td>- Focus on understanding the reservoir</td>
</tr>
<tr>
<td>- Pursue aggressive completion and treatment designs</td>
<td>- Focus on controlled optimization</td>
</tr>
<tr>
<td>- Value measured using time to payout</td>
<td>- Value measured using NPV and IRR</td>
</tr>
<tr>
<td>- Value measured well by well</td>
<td>- Value measured at the asset level</td>
</tr>
<tr>
<td>- Short term strategies are required to put startups and juniors on the map</td>
<td>- Long term strategies are boring and often go unnoticed</td>
</tr>
<tr>
<td>- Short term strategies are not easily repeatable or scalable</td>
<td>- Operators employing long term strategies are usually successful across multiple plays/basins</td>
</tr>
<tr>
<td>- <strong>Companies with successful short term strategies are often overvalued by the stock market</strong></td>
<td>- <strong>Small</strong> companies with successful long term strategies are often undervalued by the stock market</td>
</tr>
<tr>
<td></td>
<td>- <em>Every one of the worlds top 25 oil companies employs long term strategies</em></td>
</tr>
</tbody>
</table>
Example of Opposing Oilfield Strategies - Montney

• Operator A

- Minimizes D&C cost by avoiding directional drilling and using uncemented liners
- Drills toe up through multiple benches to maximize total reservoir exposure; contributes to high IP and better liquids recovery
- Large proppant volumes per stage maximizes frac area and connection to reservoir; contributes to high IP
- Flows back wells unchoked to maximize IP and minimize payout time
Example of Opposing Oilfield Strategies- Montney

• Operator B

- Spends more on D&C; drills directionally to stay in zone, uses cemented liner with pinpoint completion technology
- Uses high stage density with lower proppant volumes per stage to maximize recovery efficiency in zone and along the lateral
- Flows back wells on choke to manage liquids recovery and maintain reservoir pressure above dew point for as long as possible
### Example of Opposing Oilfield Strategies - Montney

<table>
<thead>
<tr>
<th>Strategy</th>
<th>Advantages</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operator A (Short Term)</td>
<td>- Faster payout on deployed capital</td>
<td>- Inflated shareholder value</td>
</tr>
<tr>
<td></td>
<td>- Market recognition, ability to obtain funding</td>
<td>- Risk of loss of repeatability</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Loss of future drilling inventory</td>
</tr>
<tr>
<td>Operator B (Long Term)</td>
<td>- Understated shareholder value</td>
<td>- Slower payout on deployed capital</td>
</tr>
<tr>
<td></td>
<td>- Repeatable and scalable</td>
<td>- Unimpressive IP</td>
</tr>
<tr>
<td></td>
<td>- Better long term performance and profitability</td>
<td></td>
</tr>
</tbody>
</table>
Final Thoughts

• Reservoir engineering insight can be useful in the investment community
  - Helps identify red flags
  - Helps filter out noise; focus on what is important
  - Identifies underperforming assets
  - Helps identify undervalued (or overvalued) companies

• Successful operators and management teams:
  - Are very clear on how they measure value
  - Can execute a repeatable and scalable development strategy
  - Don’t have a “silver bullet” but rather, perform to a consistent level of competence across all disciplines in the value chain
Thank-you!

Questions?