Society of Petroleum Evaluation Engineers

(SPEE)
Society of Petroleum Evaluation Engineers (SPEE)

- Formed in 1962 to bring together specialists in the evaluation of petroleum and natural gas properties
- Has over 500 members worldwide
- Strongly committed to providing education to its members and to the industry and to promote the profession of petroleum evaluation engineering
- Guided by by-laws that require the highest ethical standards while maintaining principals of acceptable evaluation engineering practice
The SPEE is a joint sponsor, along with the SPE, WPC and AAPG, of the Petroleum Resources Management System (PRMS)

Membership – bachelor’s or higher degree in engineering or geology, 10 years experience in property evaluations

Has local chapters in Houston, Austin, Central Texas, California, Dallas, Denver, Europe, Midland, Oklahoma City, Tulsa and Calgary
• SPEE (Calgary) formed in 1995, currently has 50 active members and is a registered not-for-profit society

• SPEE (Calgary) is the copyright owner of the Canadian Oil and Gas Evaluation Handbook (COGEH) Volumes 1, 2 and 3

• Currently working on guidance for Resource evaluations (Volume 4?)

• Membership includes local evaluation consultants, IQREs from E & P Companies and representatives from the ASC
Evaluating Resource Plays
In Western Canada

Presented to the SPE Inter-Society SIG
April 11, 2012

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Executive Vice-President and Director
Topics in the Presentation

• What is a Resource Play

• Type curves

• Permeability

• Examples of resource plays, reserves and economics
  • Cardium Oil
  • Viking Oil
  • Montney Gas

• Sproule’s best practices
What is a Resource Play?

• There is no single definition. Definition changes to suit the user

• The term “Resource Play” first appeared in publications in the early 1990’s

• SPEE: describes an accumulation of hydrocarbons known to exist over a large areal extent; not the classification of volumes (reserves versus resources)
Characteristics of a Resource Play (SPEE Monograph 3)

• Wells exhibit a repeatable statistical distribution of EURs

• Offset well performance is not a reliable predictor of undeveloped location performance

• A continuous hydrocarbon system exists that is regional in extent
Characteristics of a Resource Play (SPEE Monograph 3)

- Requires extensive stimulation to produce at economic rates
- Low permeability reservoir
- This is not conventional exploration
Resource Plays

• Resource plays are not new

• Accumulations are known to exist

• Our clients are exploiting and extending discovered resource plays commercially as a result of:
  • The evolution of new technology
  • Improved hydrocarbon prices
Resource Play Types

• New technologies and improved hydrocarbon prices have allowed our clients to:
  • Enhance recovery within existing plays
  • Extend the limits of previously known commerciality
  • Exploit previously unexploited reservoirs (Oilsands, CBM, Bakken)
Type Curves

• Represents an average well

• Derived from experience, analytical calculations, and observations

• Not new: used for decades

• Need more, rather than fewer, type curves as development continues and more data become available
Evolution of the Type Curve

- Reservoir simulations

- Use of analogous pools and reservoirs as more production data becomes available

- Expansion of the suite of type curves to capture differences in performance
  - Our clients identify the “sweet spots” and fine tune completions to enhance results
Evolution of the Type Curve

• Refine and expand the suite even further by:
  • Completion type
  • Completion fluid
  • Horizontal length
  • Number of frac stages
  • Frac sizes

• This process could take 5 years or more:
  • our Bakken type curves are still evolving
Impact of Technology

Permeability Terminology

- Tighter than Tight
- Tight
- Conventional

Permeability (mD)

- Extremely Tight
- Very Tight
- Tight
- Low
- Moderate
- High

0 % porosity Limestone

Granite
Montney
Good Shale Barnett
Utica & Lorraine
Sidewalk Cement
General oilfield rocks

US DOE Study
Examples of Current Resource Plays that will be the focus of this presentation

• Cardium Oil in Pembina

• Viking Oil in Dodsland and Redwater

• Montney Gas in Kaybob and Glacier
Pembina Cardium: 1950s Oil Resource Play

• 60 miles by 30 miles
• ~10 billion bbl OOIP
• Hydraulic fracturing ("fracking") necessary
1950s Resource Play Performance

Oil Production from the Pembina Cardium Pool

- 1.3 billion barrels produced as of Dec. 31, 2011
Recovery Variability in the Cardium
Current Pembina Development

- Targets areas of low or no recovery
- Typically lower permeability
- Uses mile-long horizontal wells with multi-stage fracture treatments (4 wells/sec, 14-20 stages per well)
- Presence of oil known historically in these areas
Challenges: Cardium Reserve Estimation

• What’s net pay?

• What are cut-offs for estimating pay:
  • Porosity?
  • Permeability? (many vertical wells cored)

• How far to step out for assigning undeveloped locations?

• Variability of production rates affect recoveries (therefore the need for a suite of type curves)
Pembina Cardium Type Curves

Pembina Cardium Type Curve

Oil Rate (bbl/d)

Cum Oil (Mbbl)

$D_i = 78\%$
$N = 1.0$
$t = 1$ year

$N = 0.8$
Pembina Development Inputs

- **Capital costs:**
  3.0 MM$ drill, complete, equip, tie-in

- **Operating costs:**
  $4,500/well/month, $5.00/bbl, $1.00/mcf sales

- **Initial Rate:**
  180 bopd

- **Recoveries (P+P, type 3 curve):**
  140 Mbbl oil, 2,000 scf/bbl, 45 bbl/MMcf C4

- **Royalty Incentives:**
  5% NWRR 60 Mboe, 24 Months
Pembina Development Outputs

- Finding and development cost (capex/reserves in boe)
  16.0 $/boe
- Netback (NPV10/reserves in boe)
  17.0 $/boe
- Recycle ratio (NPV10/capex)
  1.04
- Time to Payout
  1.5 years
- Internal Rate of Return (discount rate when NPV = 0)
  60%
- Economic Productive Life
  35+ years
Pembina Development Conclusions

• Horizontal well development has exploded in the last 4 years

• Development will continue
  • 4-6 wells per section, waterflood enhancement

• Performance is variable
  • Need for multiple type curves

• Short payout time, excellent ROI, incentives matter
Viking Oil Developments

• Dodsland, Saskatchewan
• Redwater, Alberta
Viking Pools in Western Canada
Undeveloped Reserves: Viking

- Good geological control

- Evidence of producibility is key:
  - Limits bookings to offsetting locations

- Reserve bookings changing as play evolves:
  - Number of wells per section
  - Lengths of horizontal legs
  - Well costs
  - Recovery per well
Dodsland, Saskatchewan

Dodsland
Characteristics of Dodsland Viking

- Discovered in 1956
- Low permeability Cretaceous sandstone
- Net pay is difficult to identify so OOIP is difficult to quantify accurately
- Thousands of vertical wells drilled
  - Initial rate of vertical well: 20 bopd
  - Recovery varies greatly
Viking Dodsland Performance

• Horizontal wells with multi-stage fracturing (10-14 stages)
• Trend is to shorter horizontal wells (800m)
  • Cost less; lower capital important
  • Cost: <$1 million
• Royalty incentives are essential
• Type curves used for estimating reserves; will change to decline analysis as play matures
• Sproule’s current model (P+P):
  • 26 Mbbl of oil (based on 16 wells/section)
Dodsland Viking Production
Redwater, Alberta
Redwater Viking Production
## Viking Inputs

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Redwater Viking</th>
<th>Dodsland Viking</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital cost</td>
<td>2.0 MM$</td>
<td>0.8 MM$</td>
</tr>
<tr>
<td>Operating costs</td>
<td>$5,000/well/month</td>
<td>$3,000/well/month</td>
</tr>
<tr>
<td></td>
<td>$3.00/bbl</td>
<td>$5.00/bbl</td>
</tr>
<tr>
<td></td>
<td>$2.00/bbl clean oil</td>
<td>$2.00/bbl</td>
</tr>
<tr>
<td></td>
<td>trucking $0.30/mcf</td>
<td>trucking $0.30/mcf</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial rate</td>
<td>115 bopd</td>
<td>35 bopd</td>
</tr>
<tr>
<td>Recoveries</td>
<td>130 Mbbl oil</td>
<td>26 Mbbl</td>
</tr>
<tr>
<td></td>
<td>1,250 scf/bbl</td>
<td>1,000 scf/bbl</td>
</tr>
<tr>
<td></td>
<td>No liquids</td>
<td>20 bbl/MMcf C3</td>
</tr>
<tr>
<td>Royalty Incentives</td>
<td>5% NWRR 100 Mboe, 48 months</td>
<td>2.5% 37.7 Mbbl horizontal oil</td>
</tr>
</tbody>
</table>
## Viking Outputs

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Redwater Viking</th>
<th>Dodsland Viking</th>
</tr>
</thead>
<tbody>
<tr>
<td>F&amp;D Costs</td>
<td>14.1 $/boe</td>
<td>27.5 $/boe</td>
</tr>
<tr>
<td>Netback (10% discount)</td>
<td>29.6 $/boe</td>
<td>13.2 $/boe</td>
</tr>
<tr>
<td>Recycle Ratio (10% discount)</td>
<td>2.07</td>
<td>0.47</td>
</tr>
<tr>
<td>IRR</td>
<td>163%</td>
<td>38%</td>
</tr>
<tr>
<td>Time to Payout</td>
<td>0.9 years</td>
<td>2.1 years</td>
</tr>
</tbody>
</table>
Viking Challenges

• Downspacing:
  • Need a simulation
• Long term profile:
  • Simulation will help
• Production practices:
  • Pumping vs flowing
  • Solution gas
  • Capacities
  • Surface water
Montney Gas

- Kaybob South, Alberta
- Glacier, Alberta
About the Montney

• Results driven by completion technology

• Typically 3 zones being developed:
  • Upper, Middle and Lower

• Reserves assignments proportional to initial deliverability:
  • RLI 2.5 to 3.0 from gas rate in second month

• Steep initial declines
More on the Montney

• High variability in performance of wells in same area

• Most operators believe rates and reserves related to number of fracture stages

• Categorize areas by rates per fracture stage

• Rule of thumb: one fracture stage in a horizontal well replaces a vertical well
Montney Type Curves, Alberta

Variety of type curves modelling performance of number of treatments

ERCB ST 98-2011
Even More on the Montney

• Liquids recovery and royalty incentives improve profitability
  • Liquid yields are highly variable

• Results improve as completions optimized

• Issues:
  • Performance of infill wells
  • How far to extend reserve bookings
  • Infrastructure access
  • Number of undeveloped bookings per producing well
Montney Gas Wells

- Montney extends over a wide area
- Rock properties vary
- Reserve booking must take into account rock and production variability
Gas Production from the Montney

Montney Production

- Vertical Daily Gas Prod
- Horizontal Daily Gas Prod
- Vertical Wells On Prod Per Year
- Horizontal Wells On Prod Per Year

- Year
- Gas Production (MMcf/d)
- Number of Wells On Prod Per Year

Graph showing the increase in gas production and number of wells on production per year.
Montney Type Curves

Montney Type Curves

- Kaybob South
- Glacier

N = 2.0
N = 0.7

$N = f(t; Q_f = 0.4Q_i)$

Cum Gas (MMcf)

Gas Rate (Mcf/d)

$N = 2.0$
$t=6$ months
$Q_f = 40\%$ of $Q_i$
# Montney Inputs

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Kaybob South Montney</th>
<th>Glacier Montney</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital cost</td>
<td>3.5 MM$</td>
<td>6.0 MM$</td>
</tr>
<tr>
<td>Operating costs</td>
<td>$6,000/well/month $1.00/mcf</td>
<td>$7,500/well/month $0.50/mcf</td>
</tr>
<tr>
<td>Initial rate</td>
<td>4 MMcf/d</td>
<td>6 MMcf/d</td>
</tr>
<tr>
<td>Recoveries</td>
<td>2.5 Bcf 8 bbl/MMcf C3 7 bbl/MMcf C4 15 bbl/MMcf C5+</td>
<td>4.5 Bcf No liquids</td>
</tr>
<tr>
<td>Royalty Incentives</td>
<td>5% NWRR 50 Mboe, 18 months NGDDP 1500 M$</td>
<td>5% NWRR 50 Mboe, 18 months NGDDP 2500 M$</td>
</tr>
</tbody>
</table>
# Montney Outputs

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Kaybob South Montney</th>
<th>Glacier Montney</th>
</tr>
</thead>
<tbody>
<tr>
<td>F&amp;D Costs</td>
<td>1.35 $/mcfe</td>
<td>1.49 $/mcfe</td>
</tr>
<tr>
<td>Netback (10% discount)</td>
<td>1.33 $/mcfe</td>
<td>0.32 $/mcfe</td>
</tr>
<tr>
<td>Recycle Ratio (10% discount)</td>
<td>0.96</td>
<td>0.21</td>
</tr>
<tr>
<td>IRR</td>
<td>60%</td>
<td>17%</td>
</tr>
<tr>
<td>Time to Payout</td>
<td>1.6 years</td>
<td>4.2 years</td>
</tr>
</tbody>
</table>

*Note the effects of the liquids on the economic indicators.*
Montney Challenges

- Low gas prices
- Liquid yields
- Geological variability
### Summary of Examples

<table>
<thead>
<tr>
<th>IRR (%)</th>
<th>Netback ($/boe)</th>
<th>F&amp;D ($/boe)</th>
<th>Recycle Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Glacier Montney</td>
<td>17</td>
<td>1.9</td>
<td>9.0</td>
</tr>
<tr>
<td>Kaybob South Montney</td>
<td>60</td>
<td>8.0</td>
<td>8.1</td>
</tr>
<tr>
<td>Dodsland Viking</td>
<td>38</td>
<td>13.2</td>
<td>27.5</td>
</tr>
<tr>
<td>Redwater Viking</td>
<td>163</td>
<td>29.6</td>
<td>14.1</td>
</tr>
<tr>
<td>Pembina Cardium</td>
<td>60</td>
<td>17.0</td>
<td>16.0</td>
</tr>
</tbody>
</table>

- **Redwater Viking is the most profitable of these plays**
- **Liquids in Kaybob South Montney play make it comparable to Pembina Cardium light oil play**
Summary of Examples

Cumulative Cash Flow Comparison

- Pembina Cardium
- Redwater Viking
- Dodsland Viking
- Kaybob South Montney
- Glacier Montney
Sproule’s Best Practices

• Software to develop type curves (ValNav, Visage)

• Evaluations done on industry reserves management software (ValNav, Mosaic)
Advantages of Sproule’s Best Practices
Web-Based, 24/7 Approach

• Sproule’s type curves and regional studies are available to our clients through our web-based approach

• Sproule’s practices are evolving with our clients and the way we interact with our clients is also evolving
Advantages of Sproule’s Best Practices
Web-Based, 24/7 Approach

• Allows clients to take our year-end database to work on and augment throughout the year

• Database can be housed at client facilities and accessed by Sproule via the Internet (Citrix)

• Client is live (read-only), increasing efficiency of the evaluation process
Continuous Improvement

• Use of specialized, multi-disciplinary teams to evaluate evolving plays

• For all resource plays, we continuously review, revise and enhance our practices based on additional production data and evolving operator/client practices – summer projects

• Sproule also has a dedicated team of professionals who stay knowledgeable about evolving technologies
Summary of Presentation

• Challenges in evaluating resource plays
• Examples for some resource plays
• Sproule’s best practices
Thank you for your attention!
Contacting Sproule

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