Type Well Curve Process - Cardium

Geoff Beatson – 2014
Role at Sproule
- Senior Engineering Advisor and Partner
- Joined in 2012
- Performs corporate, property, and A&D evaluations
- Estimates reserves and project economics for O&G properties
- Creates and monitor type curves for various WCSB resource plays
- Performs contingent and perspective resource assessments

Prior Experience
- PetroBakken
  - Manager, Reservoir Engineering
- Tango Energy
  - VP, Engineering & Operations
- GWB Petroleum Consultants
  - President & CEO
- Watch Resources/Energy 51
  - VP of Engineering & Operations
- Bunker Energy Inc.
  - VP of Engineering
- Encal Energy Ltd.
  - Director of Engineering & Economics
AGENDA

1. Nomenclature
2. Why use Type Well curves
3. Theory behind using multi-segment curves
4. Type Well curve generation process
5. Factors affecting Type Well curves
6. Applying Type Well curves
7. Ongoing issues with Type Well curves
8. Q & A
Cardium Expertise – Build better Understanding by Analyzing full Play Extent

Clients across whole play > 16,500 wells
Nomenclature “Type Well” Vs. “Type Curve”

- **Type Curve** typically refers to a theoretical response based on a homogeneous reservoir model that is perfectly completed under constant pressure drawdown conditions.

- **Type well** uses actual well performance data that accounts for reservoir heterogeneities, non perfect completions and varying operating conditions.
Evolution of Type Well Curves – 1\textsuperscript{st} Type Curve?

Normalized then divided by peak rate

Evolution of Type Well Curves

Fig 1  Cardium oil production in Western Canada

Source: Bloomberg, geoSCOUT, Macquarie Research, November 2011
PROBLEM: Increase horizontal well drilling with no production history or analogies. NEEDED A WAY TO FORECAST WELLS

- Original forecast generated from radial flow model or simulator, vertical well results other reservoir analogies
- Over time, had some analogies to use. Still need more time to confirm the “tail”
- Better than volumetric’s as it is difficult to define net pay, varying porosity/permeability, Sw and Area
- Better than Energy Balance due to volumetric issues as well as seldom get a good Rsi, Pi, PVT, defined sweep efficiency, rel. perm → changing GOR, drive mechanism.

SOLUTION: Type Well Curves summarize average well performance decline profile to permit effective forecasting and reserve estimation for evaluations. (Trick Arps as not in boundary dominated flow)
Theory of Type Well Curves - Shape
ABCs of Reservoir and Well Dynamics: Controlling Factors

- Completion
- Near wellbore permeability
- Pressure support
- Drive mechanism
- Far field permeability
- Transition

Decline rate is steep ~65%/yr in first year, generally caused by:
- Transient effects
- Pressure depletion
- Increasing gas saturation

Secondary recovery will become critical to maintain a higher plateau oil rate:
- Lack of drive energy

First year production
Evolution of Type Well Curves – Why Peak Rate

Good to normalize on peak rate as it takes a while to see transition flow due to initial operating practices

Bob Bachman
Evolution of Type Well Curves – Why $n > 1.0$

Problem when using $n < 1$, s.b. closer to 2.0
First Segment Generation

1. Select Hz Oil wells after 2009 (new completion type)
2. Review data to ensure sample accuracy (zone, abnormal performance)
3. Use Op Daily rates to generate normalized peak rate (remove s.i. months) curve by TWP (calendar daily doesn’t show true performance, normalizing on equivalent time may accelerate forecast if ontime < 100%)
4. Review GOR performance/trend – segregate oil and gas wells
5. Use performance of longer producers to add “tails” to newer wells, re-normalize. Include ramp cum.
6. Save curve and select range of data to use and length of 1\textsuperscript{st} segment
7. Match first segment of curve with decline tools
3) Select > 2009 Hz oil wells. Review wells for abnormal performance/zone

Can refine based on completion type and drilling criteria with correct Binning

Average well not P50
5a) Use Op daily, normalize on peak rate by TWP, select 1st segment, review GOR

Once profile is determined by longer producers, apply to newer wells, then re-normalize $\rightarrow$ Type Well
5b) Adding tail maintains well count for 1st segment

Software now includes option to maintain well count. Could have opposite situation $\rightarrow$ better newer completions
5c) Determining how “n” is changing during linear/transition flow

Also know that lower load fluid recovery can create skin thus “n” appears < 2.0. Also inter frac communication may mask transition flow.

Check that final decline rate is reasonable to represent stabilized flow 20%<d>10%
5d) Load fluid and inter-frac boundary dominated flow may reduce “n”
7. Match trend with decline tools --> parameters
Second Segment Generation

There is the notion of using three segments to properly forecast wells but it is time consuming. Sproule uses two segments (some competitors use one). Utilizing a “minimum decline” Sproule actually uses three segments. The second segment is developed utilizing the following information and experience:

- In house simulation and sensitivities
- Decline nature of more mature Hz producing from similar reservoirs
- Studying decline behavior of vertical wells
- Analyze formation – Flow/BU tests, DFIT’s, core studies
- Reviewing results of applying reasonable declines & “n” to second segment
- Also know that for boundary dominated flow: $n < 1$ multi layer, $n < 0.5$ single layer
- Determining how “n” is changing during linear/transition flow
- Resource studies – volumetrics $\rightarrow$ reasonable recovery factors

*This process is updated every year with new production and assumptions verified*
Second Segment – Forecast “Tail” – match declines, use reasonable “n”
Type Well Generation – Quality Control Checks

1. Plot TWP curves on map and select area groupings
2. Compare to last years curve sets. Review IP’s for realistic 1P/2P rates
3. Determine range for type wells based on performance of existing wells
4. Adjust q2 & decline of second segments “tail” to ensure even spacing of curves
   (decline & “n” for gas wells appear > oil wells)
1. Plot TWP curves on map and select area groupings

Broke into four areas last year
2. Compare to last years curve sets

Normalized plot compared to 2012 Cardium type curves

- Willesden Green TWP 040-05W5
3. Determine Range of Variability → Approximate P10 - P90, space out curves
Type Curve - Areas

- Central Pembina (7 curves)
- SE Pembina (7 curves)
- NW Pembina (4 curves)
- West Pembina (7 curves)
- High GOR (5 curves) – building gas curves for gassy areas
- Edson / Carrot Creek (6 curves)
- Rosevear (6 curves)
- Lochend (7 curves)
- Garrington/Harmattan (7 curves)
- Wapiti (4 curves)
- Brazeau/Ferrier / Willesden Green (4 curves) – adding more curves

- Currently 64 total + ½ curve’s
The following process shows how Sproule books undeveloped locations < 2 mi.

1. Determine best fit for area (preferably Cum or may use Rate)
2. Match **offset well performance** to 2P then adjust 1P
3. Adjust timing, yields and price offsets, op costs (economics)
4. Check sections CTD (old vertical wells) for remaining volumes

Until wells reach boundary dominated flow, Sproule currently assigns reserves:
- Wells > 4/section receive 50% of type well curve

Until performance supports, Sproule currently assigns reserves:
- Wells drilled in zone >2 mile wells get 150% of type well curve
1) Applying curves – Select Type #

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<th>9 Mo Cum (Mbbl)</th>
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2) Applying curves – Input Decline Variables

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Updated: Sept 5, 2013
CENTRAL PEMBINA AREA
FOR WELLS LOCATED IN TWP 47.50, RGE 7.10.

Type 1 - Central Pembina Type Profile PUD = 30 MSTB, P+PUD = 45 MSTB (Flat GOR Forecast as appropriate for the vicinity of the location)

Type 2 - Central Pembina Type Profile PUD = 60 MSTB, P+PUD = 85 MSTB (Flat GOR Forecast as appropriate for the vicinity of the location)
3) Applying curves (Economics) – Adjust timing, yields and price offset, op costs

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<th>Trend Cum. ΔCum</th>
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The process for used for producing wells is similar but takes a few tweaks:

1. Determine best fit for area (preferably Cum or may use Rate) to match **current well performance** to 2P then adjust 1P
2. Review surrounding well allocations (consistent bookings)
3. Match to Current Op Rate and cum – walk down curve
4. t1 match – adjust for remaining months of linear/transition flow
5. Use two segment unless well has transitioned → own decline
6. Watch for discrepancies 2P/1P remaining reserve ratios
7. Make sure declines > ~5% and reserve life < 50 years
8. Water flood wells handled specifically, not with type well curves
1. Determine best fit for area (preferably Cum or may use Rate) to match current well performance to 2P then adjust 1P

---

**Pick as Type 2.5**
2. Review surrounding well allocations (consistent bookings)
3. Match to current rate, decline and Remaining Cum.

Due to n>0 decline rate lessens over time (D1i>D1f). Endure D1f of first segment to D2i of second segment.
4. t1 match – adjust for remaining months of linear/transition flow
5. Use two segments unless the well has transitioned → 2nd segment → own decline
6. Watch for discrepancies 2P/1P remaining reserve ratios – ratio shouldn’t increase

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<tr>
<th>1P</th>
<th>2P</th>
<th>Cum</th>
<th>RATIO 2P/1P</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>130</td>
<td>0</td>
<td>1.3</td>
</tr>
<tr>
<td>65</td>
<td>95</td>
<td>35</td>
<td>1.5</td>
</tr>
<tr>
<td>50</td>
<td>80</td>
<td>50</td>
<td>1.6</td>
</tr>
<tr>
<td>40</td>
<td>70</td>
<td>60</td>
<td>1.8</td>
</tr>
<tr>
<td>35</td>
<td>65</td>
<td>65</td>
<td>1.9</td>
</tr>
<tr>
<td>30</td>
<td>60</td>
<td>70</td>
<td>2.0</td>
</tr>
</tbody>
</table>
6. Remaining reserve ratios should decrease over time – eventually $1P = 2P$
7. Make sure declines > ~5% and reserve life < 50 years
8. Water flood wells handled specifically, not with type well curves
Continuing Issues

- Sometimes Rate matches better than Cum (operational issues?)
- Length of well – performance, 2 mile (maximize incentive)?
- High GOR --> Gas wells - flared gas during tie-in, review offsets, conservative
- Hybrid curves – no PVT data to vary OGR or GOR.
- Operating practices – clean-outs → open ports, pump depth (head), fracture conductivity reduction, wax, gas lock, efficiency, fines build up
- Completion – stages, volumes, spacing, fluid, pump rate, orientation, wing/complex
- Transition zone – add 3rd segment to smooth curve
- Have not seen when boundary dominated flow - varies by Reservoir/well spacing, development timing → well interference/optimum well spacing?
- Water floods → When break thru occurs – drilling deeper HZ in old vertical floods
- Section drilled / well placement in zone
- Reservoir – “A”, “B”, Both, conglomerate, channel, barrier bar, shore face, natural fractures, faults, bioturbation (Vert. perm), grain size, sand content

Thus Sproule uses PERFORMANCE BASED MULTI-SEGMENT reserve estimates
Well Completions - fluid

Completion type test- Lochend Oil Fracs

- Province: Alberta
- Field: n/a
- Pool: n/a
- Unit: n/a
- Status: n/a
- Operator: n/a

![Graph showing Completion type test- Lochend Oil Fracs](image-url)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cum Oil (bbl)</td>
<td>17,073</td>
</tr>
<tr>
<td>Cum Gas (MMcf)</td>
<td>59,246</td>
</tr>
<tr>
<td>Cum Water (bbl)</td>
<td>273</td>
</tr>
<tr>
<td>Cum Cond (bbl)</td>
<td>0</td>
</tr>
<tr>
<td>Calculation Type</td>
<td>Undefined</td>
</tr>
<tr>
<td>Ext. Cum Prod (bbl)</td>
<td>0</td>
</tr>
<tr>
<td>Remaining (bbl)</td>
<td>70,613</td>
</tr>
<tr>
<td>Initial Decline (%/yr)</td>
<td>99.9</td>
</tr>
<tr>
<td>Oil Rate (Stb/ft³)</td>
<td>3.1</td>
</tr>
<tr>
<td>Gas/Oil Ratio (stb/ft³)</td>
<td>3.1</td>
</tr>
<tr>
<td>Calendar Daily Oil Production (Stb/day)</td>
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<tr>
<td>Operating Daily Oil Production (Abil/day)</td>
<td>0.1</td>
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<tr>
<td>Number of Oil Wells</td>
<td>1</td>
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<tr>
<td>Water Cut (%)</td>
<td>0</td>
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</tbody>
</table>

Sproule
Completion type test- Lochend Slickwater Fracs

Province: Alberta
Field: n/a
Pool: n/a
Unit: n/a
Status: n/a
Operator: n/a

Test Cardium
LGC sw frac
Proved Developed Producing

<table>
<thead>
<tr>
<th></th>
<th>S1</th>
<th>S2</th>
<th>PDP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cum Oil (bbl)</td>
<td>73,410</td>
<td>169,088</td>
<td>680</td>
</tr>
<tr>
<td>Cum Gas (Mrft)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oiap (bbl)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Est. Cum Prod (bbl)</td>
<td></td>
<td>215,472</td>
<td></td>
</tr>
<tr>
<td>Decline Exponent</td>
<td>5.472</td>
<td>1.220</td>
<td></td>
</tr>
<tr>
<td>Initial Decline (°/yr)</td>
<td>99.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial Rate (bbl)</td>
<td>400.0</td>
<td>0.000</td>
<td></td>
</tr>
<tr>
<td>Recovery Factor</td>
<td>0.000</td>
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<tr>
<td>Final Rate (bbl)</td>
<td>2.0</td>
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</tr>
<tr>
<td>Ult. Recoverable (bbl)</td>
<td>210,000</td>
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</tr>
</tbody>
</table>
Continuing Issues – Wing Vs Complex
Continuing Issues - placement
Continuing Issues – Reservoir variation
SUMMARY

“We needed a way to forecast new Hz wells with no production history or direct analogies → Type Well Curves”

- Decline analysis is the most common method for forecasting (NI 51-101)
- Over time Sproule has built, updated and improved type curve suites for various fields → how will “tail” perform
- Software advances have improved and made possible the analysis of significant volumes of data and correct selection of wells → binning
- When well exhibit a stabilized trend, move to individual declines to better match specific well performance to estimate reserves

Sproule will continue to investigate and attempt to quantify key performance variables like completion type, water floods, well length, well placement and infill well density
Any Question or Comments please.........