Drill Bits

Alberta Bound? - The Renaissance of the Alberta Viking

BMO Capital Markets - Energy - A&D Advisory

May 2017
Overview

- In pursuit of light oil and following the successful development of the Bakken with horizontal wells, attention has turned to the Viking in the Dodsland area of Saskatchewan.

- Until early this decade, Dodsland had been developed using vertical well technology targeting just the most permeable areas of the trend and produced significant quantities of both oil and gas.

- In 2010 production was about 16 Mboe/d from the Dodsland area and then a resurgence began using horizontal wells, to a peak production of 71 Mboe/d in 2015. Since then, production had fallen to a low of 50 Mboe/d in 2016 before rebounding to more than 62 Mboe/d in February 2017.

- The maturation of Dodsland has forced operators to look west on the trend for growth opportunities into Alberta and the Provost area where thick (7-10 m), heterogenous marine and shoreface sands have produced significant oil and gas over a number of decades with vertical well technology.

- Our review will compare the Dodsland and Provost areas, looking specifically at successful strategies for development at Provost and the remaining opportunities to determine whether the renaissance of the Viking is truly Alberta Bound.

The Viking is a world-class light oil play, Dodsland extensively developed in the last decade. Provost is emerging as an extension of Dodsland, where adopted D&C techniques are equally successful.
Viking - The Evolution from Gas to Oil Production

Provost and Dodsland Proximity to Major Gas and Oil Sales Lines

- Gas production started in the Viking at Provost from large gas units in 1945 and was originally consumed only within Alberta.
- With the completion of the Trans Canada mainline in 1958, the Provost-Dodsland Viking play became an important source for the nation’s gas supply as well as setting the stage for key infrastructure routes.
- Provost’s historical oil and gas production has been overshadowed by the tremendous success and focus on horizontal oil development at Dodsland in the last few years.
- Following in the footsteps of the successful Dodsland development, attention has turned to the Provost area where significant untapped oil resources remain.

\textit{Unitized Viking gas originally helped fill the TCPL mainline and provides a legacy of infrastructure to leverage any go forward development.}
More than Sixty Years of Viking Production in Provost and Dodsland

Viking - Provost is the Original Viking

Horizontal drilling has unlocked Viking oil successfully at Dodsland and now Provost

Source: GeoSCOUT, BMO Capital Markets
Viking Geology - A Regionally Extensive Sand Package

Regionally, the Viking is composed of a distinct series of coarsening-upward, prograding shoreface sands widely deposited on a broad shelf.

In eastern Alberta and Saskatchewan (focus area), the thinner and shalier Viking is reflective of a deeper shelf depositional setting where pulses of sediment influx (from the southwest) created the stratigraphically complex, thinly bedded, lithic siltstones and fine-grained sandstones. Volcanic activity at that time also brought in significant amounts of ash creating areas within the Viking with abundant swelling clays.

Viking sands are oil and gas charged, where trapping is primarily stratigraphic. Regional structure will influence reservoir configuration, an example being the gas pools at Dodsland which occur on structural highs (likely related to Devonian salt dissolution that created surrounding lows).

For decades, vertical drilling targeted the conventional reservoir sands like the Hamilton Lake shoreface deposit in western Provost or areas where stacked thin sands present as a single, thick sand.

Generally, the original Viking development was gas focused on the Alberta side, and oil with distinct gas pools on the Saskatchewan side. Waterflood projects were successfully implemented in the oil pools on both sides of the border.

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1. Modified after 2005, SGS Hoosier SK Viking

Provost and Dodsland Oil and Gas Producing areas

Stratigraphic Trapping (1):

- SW
- Regional Dip
- Gas
- Oil
- NE
- Viking Sands

Structural Trapping:

- NW
- Gas
- Oil
- SE
- Viking Sands
The schematic model shows a simplified depositional environment for the Provost/Dodsland Viking where the more distal sands are thinner and finer grained. As the relative sea level fluctuates, thin sands are overlain by distal delta facies, or storm beds.

At the time of sand deposition, sporadic volcanic activity to the west brought volcanic ash, creating areas with high mud and clay content. Because of the locally abundant bentonite and associated swelling clays, using water-based drilling muds or gel fracs can easily damage the formation.

With the introduction of horizontal drilling and fracing technology, the thinner, shalier and often tighter regional sands have become economic to produce, unlocking access to significant reserves.

Better rock consistency further from the shoreface leads to more predictable drilling results.
Geological Setting - Dodsland

101/14-09-033-23W3 - Kerrobert

- OOIP 6.5 MMbbl/section
- Average Core Porosity 25%

101/06-05-030-25W3 - Whiteside

- OOIP 11.2 MMbbl/section
- Average Core Porosity 21%

141/11-04-030-22W3 - Dodsland

- OOIP 12 MMbbl/section
- Average Core Porosity 21%

101/16-15-026-19W3 - Plato

- OOIP 13 MMbbl/section
- Average Core Porosity 20%

111/08-04-031-18W3 - Dodsland

- OOIP 10 MMbbl/section
- Average Core Porosity 22%

- Logs with associated cores from the Viking pool were selected and compared
- Logs often underestimate the porosity and thickness of the pay zones. Conversely the core analysis is often from the best looking reservoir and so does not take into account the full volume of shale within a zone
- The Dodsland logs show the variability within the Viking, both single and stacked sands with variable porosity and permeability. Because of the uncertainty around net pay, the OOIP values are an estimate

Reservoir heterogeneity is minimized by horizontal drilling
The Viking is a complex assemblage with variability in deliverability and storage

Source: GeoSCOUT, GeoEDGES, Corporate Presentations, BMO Capital Markets

OOIP Calculations are based on $S_w$ 35%, 75% of gross sand thickness

BMO Capital Markets
### Geological Setting - Provost

- **Hamilton Lake wells** contain a lower, clean shoreface sequence with higher porosity and permeability than elsewhere in the focus area. The sand is amenable to and has been extensively waterflooded.
- The muddy, bioturbated upper sands at Hamilton Lake are typical of the more common Viking regional deposits.
- At Provost, upper sands more closely resemble those distal facies seen at Dodsland, where thinly bedded sand and shale prevail.

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**Log porosity values under-estimate true net pay, thus underestimating OOIP**

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**Sources:** GeoSCOUT, GeoEDGES, Corporate Presentations, BMO Capital Markets

**OOIP Calculations are based on Sw 35%, 75% of gross sand thickness**
In Dodsland, the Viking sands were deposited in a transitional offshore shallow marine environment. The reservoir consists of centimetre-scale, parallel-laminated and bioturbated oil-bearing sands and interbedded marine shales with locally abundant swelling clays.

Net pay is difficult to calculate due to the volume of shale (V_{SH}) layered and bioturbated into the sands; V_{SH} can range from 10 to 60%.

Some operators have used UV light and digital pixel point counting to help in estimating the volume of oil bearing sands.

There is a wide range of porosity and permeability throughout the area, with porosity ranging from 15-27%, permeability 0.2-80 mD from conventional core analysis.

Oil gravity is around 36° API.

The Viking at Dodsland, as compared to Provost, is increasingly homogeneous and tighter.
In Provost, three Viking sands are identified, with the lowermost sand having the highest permeability and porosity (shoreface sands). Overlying that are more muddy, lithic, heavily bioturbated sands.

Vertical permeability in the upper zones is limited by shale stringers with horizontal permeability often 10 times better than vertical.

This helps to explain the wide range in production over relatively small distance, as the lithologies can vary.

Horizontal wells that porpoise through the formation and unlock the multiple layers of sand are the best producers. Some operators are placing wells in the upper sands and fracing into the lower clean sand to access additional reservoir.

Variable lithology creates opportunities for technically nimble operators - Petrophysical studies will help to unlock opportunities.

Both Provost and Dodsland land positions are tightly held through legacy production

Source: GeoSCOUT, BMO Capital Markets, GeoEDGES
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Source: GeoSCOUT, BMO Capital Markets

Note: All production values are raw oil and gas volumes collected from public sources and do not include any extracted natural gas liquids. Oil rates include condensate volumes which account for less than 1% of the total liquids. Well counts and Production are as of February 2017.

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**Production by Operator - Increasing Production and Percent Liquids in All Areas**

**Provost Production by Operator (Cal Day Mboe/d; Liq. %)**

![Graph showing production by operator for Provost region](image)

**Provost Drilling Activity (# wells spud)**

![Bar chart showing drilling activity for Provost region](image)

**Dodsland Production by Operator (Cal Day Mboe/d; Liq. %)**

![Graph showing production by operator for Dodsland region](image)

**Dodsland Drilling Activity (# wells spud)**

![Bar chart showing drilling activity for Dodsland region](image)

**Dodsland shows noticeable development beginning in 2012**

**Provost production has been stable until late 2016 when production began to increase**

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**Dodsland Drilling Activity (# wells spud)**

![Bar chart showing drilling activity for Dodsland region](image)

**Dodsland Production by Operator (Cal Day Mboe/d; Liq. %)**

![Graph showing production by operator for Dodsland region](image)

**Provost Production by Operator (Cal Day Mboe/d; Liq. %)**

![Graph showing production by operator for Provost region](image)

**Provost Drilling Activity (# wells spud)**

![Bar chart showing drilling activity for Provost region](image)
At the end of 2009, there had been 255 MMbbl (liquids) and 2.98 Tcf (gas) recovered. At that time, there were ~9,300 wells producing and most were vertical.
Since 2009, there has been approximately 16 MMbb of oil captured at Provost and 83 MMbb at Dodsland. As capital is deployed more aggressively at Provost, oil capture will follow with area of interest clearly emerging.

Source: GeoSCOUT, BMO Capital Markets, GeoEDGES
Techniques Used to Exploit this Oil-rich Viking Resource

Horizontal development in previously thought to be only gas producing areas

Downspacing - 200 m interwell spacing

Horizontal development in previously water flooded areas

Longer lateral length increases economics of play

Dodsland strategies are key to unlocking Provost oil
Oil and Gas Recovery - Does Previous Gas Production Matter?

**Provost Gas and Oil (Twp 035-05W4)**

- At Provost, PennWest (now High Ground) has tested the strategy of drilling oil wells into previously drilled gas sections
- Where 0.5 Bcf of gas was produced previously (Sec 22-035-05W4), two laterals were drilled – resulting in stabilized rates of 35-48 bbl/d of oil
- To the east in Section 24-035-05W4, just 0.1 Bcf of gas had been produced prior to drilling four laterals. These four wells have stabilized oil rates of 58-82 bbl/d, significantly higher than the results in Section 22

**Dodsland Gas and Oil (Twp 030-24W3)**

- Encroaching on the previously produced gas section of 32-030-24W3 after 1.6 Bcf had already been produced, a single horizontal was drilled by Spur (now Tamarack Valley). The new horizontal well had a stabilized initial production rate of 25 bbl/d
- To the east in Section 34-030-24W3, Whitecap drilled three horizontal wells after 0.8 Bcf of gas had been produced. The three horizontals had stabilized rates of 32-60 bbl/d
- Like in Provost, higher rates are observed where less gas had been removed

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**Oil is recoverable at economic rates where gas had previously been produced**
Horizontal Development in Gas Areas Produces Oil - Dodsland

Section 25-032-20W3 (Teine Energy)

- The first horizontal oil well drilled in this nine-section area was 15-25-032-20W3 in Nov 2011
- Prior to this, only the vertical gas wells shown were producing. By Nov 2011, the gas wells had cumulative production of 2.7 Bcf and only 1.7 Mbbl

Section 25-032-20W3 Rate vs Time

- OOIP estimate 10 MMbbl
  - 5 m @ 22% Φ
  - 3 MMbbl
  - 3 m @ 22% Φ

- Cumulative Gas
  - 0.1
  - 365

- Cumulative Oil/Cond
  - 6
  - 163

- Surrounded sections, CTD Prior to Nov 2011
  - 2.7 Bcf

- CTD 84.6 Mbbl
  - 295 MMcf

- Avg. IP30 = 53 bbl/d

- EUR = ~150 Mbbl

- RF
  - 5% (3 m of pay)
  - 1.5% (5 m of pay)

- Downspacing provides incremental recovery

All of the horizontal wells shown were drilled into an area that had previously only produced gas from vertical wells

The oil wells have average IPs of more than 50 bbl/d and GORs of ~3,000 scf/bbl

Source: GeoSCOUT, GeoEDGES, BMO Capital Markets
Note: All production values are raw oil and gas volumes collected from public sources and do not include any extracted natural gas liquids
Section 24-035-05W4 (High Ground Energy)

- Similar to the Dodsland example, the first horizontal oil well drilled in this nine-section area was 13-24-035-05W4 in July 2011
- While more vertical gas wells were producing here (36), they had cumulative gas of 3.6 Bcf, but with significantly more liquids of 134 Mbbl
- Despite this, these oil wells are clearly recovering incremental volumes

400 m inter-well spacing (4 wells per section) suggests a recovery factor of 1% to 5%

Dodsland recovery factors at 6 to 9% - Provost could easily support 200 m downspacing
Development at 200 m Well Spacing Increases Reserves - Dodsland

Section 36-032-20W3 (NAL Resources)

- The low permeability and tight nature of the reservoir at Dodsland means downspacing will be successful at accessing more reservoir
- The first wells were placed at 400 m spacing (black wells) and followed up with 200 m spacing (pink wells). This resulted in almost doubling the recovery
- Operators (Tamarack Valley) are now testing tighter spacing (150 m, 100 m)

Section 36-032-20W3 Rate vs Time

- Avg. IP30: 48 bbl/d
- 200 m spacing: ~800 Mbbl RF 12% (3 m of pay) 7% (5.4 m of pay)
- 400 m spacing: 50 Mbbl per well

Section 36-032-20W3 Rate vs Cum

The section shown was originally drilled to 400 m spacing, but increasing the drill density to 200 m spacing has doubled the ultimate recovery

Source: GeoSCOUT, GeoEDGES, BMO Capital Markets

Note: All production values are raw oil and gas volumes collected from public sources and do not include any extracted natural gas liquids
Development at 200 m Well Spacing Increases Reserves - Provost

Section 28-034-08W4 (Tamarack Valley)

-_while the permeability may be better at Provost, the laminated nature of the sands suggests that increased downspacing will access additional oil

- In the Provost section shown here (28-034-08W4), the first two wells were spaced at 400 m. Subsequent wells were drilled at 200 m spacing leading to more than doubling of recovery

Five wells at 200 m spacing with each having an average IP30 of 71 bbl/d
Re-Entering Waterflood Areas Dodsland - Highly Successful Horizontal Infill Wells

Section 26-031-23W3 (Raging River)

- Prior to Aug 2014, there were 15 vertical oil wells that had cumulative production of 1.4 MMbbl
- Even though injection stopped in 1998, the horizontal wells are indicating pressure support and increased EUR of nearly 2 MMbbl
- Raging River has two additional horizontals licensed in this section

Section 26-031-23W3 Rate vs Time

- Water cut decreases with Hz wells

Section 26-031-23W3 Rate vs Cum

- Injection stopped in 1998
- EUR ~1,900 Mbbl
- RF 16%

Horizonal wells drilled into the same zones that were flooded have surprisingly low water cuts
Re-Entering Waterflood Areas Provost - Highly Successful Horizontal Infill Wells

Section 27-035-10W4 (Toro Oil and Gas)

- The four vertical wells in this section at Hamilton Lake produced more than 650 Mbbl while under waterflood
- The horizontal well was drilled 12 years after water injection stopped and is showing signs of pressure support with an EUR of nearly 150 Mbbl

Section 27-035-10W4 Rate vs Time

- Water cut decreases

Section 27-035-10W4 Rate vs Cum

- EUR ~800 Mbbl
- RF 17%

Years after water injection stopped there is indication of continuing pressure support

Source: GeoSCOUT, GeoEDGES, BMO Capital Markets
Note: All production values are raw oil and gas volumes collected from public sources and do not include any extracted natural gas liquids
At Dodsland, one mile laterals are not significantly better than three-quarter mile laterals, however all long laterals show significant performance improvement over half-mile laterals.

Expected DC&T well costs for 2017 are $650M for the standard 1/2 mile wells, $800M for the ERH (Extended Reach Horizontal) 3/4 mile wells, and $970M for the 1 mile wells.

**Three quarter mile wells appear to provide the best return**
Longer Lateral Length Provost – Exposure to Reservoir is Key

Provost Horizontal Wells Drilled Since 2014

Lateral Length Drilling Activity

- 1 mile Laterals
- 3/4 Mile Laterals
- 1/2 Mile Laterals

Lateral Length Well Performance

- 1 Mile Avg (n=98)
- 3/4 Mile Avg (n=291)
- 1/2 Mile Avg (n=386)

At Provost, the one mile laterals show much better initial deliverability than the three-quarter mile wells and are the emerging length of choice where land permits

Map Area

- Lateral Length 1.0 mile
- Lateral Length 0.75 mile
- Lateral Length 0.5 mile
- Other Viking Wells
- Viking Shoreface

DC&T well costs for Provost wells are similar to Dodsland

Source: GeoSCOUT, GeoEDGES, BMO Capital Markets
Note: All production values are raw oil volumes collected from public sources
n = number of wells
Increased lateral length and proppant placement paired with significant decrease in costs

Note: All production values are raw oil and gas volumes collected from public sources and do not include any extracted natural gas liquids. Oil rates include condensate volumes which account for less than 1% of the total liquids. Data subset are wells Spud post Jan 1, 2014

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**Provost Horizontal Development - Completion Techniques**

**Completion Length (m) and Stage Spacing**

- **Completed Length**
- **Stage Spacing**
- **# Stages**

<table>
<thead>
<tr>
<th>Year</th>
<th>Completed Length (m)</th>
<th>Stage Spacing</th>
<th># Stages</th>
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<tr>
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<td>800</td>
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<td>2016</td>
<td>200</td>
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**Proppant Placement and Fluid Type**

- **Foam**
- **Gelled Water**
- **Slickwater**
- **Proppant Placed**

<table>
<thead>
<tr>
<th>Year</th>
<th>Foam</th>
<th>Gelled Water</th>
<th>Slickwater</th>
<th>Proppant Placed (ton)</th>
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<td>0.2</td>
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<tr>
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<td>2014</td>
<td>0.2</td>
<td>0.1</td>
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<td>2016</td>
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**Total Proppant Placement**

- **Total Proppant**
- **Placement Success**

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<th>Year</th>
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<td>98%</td>
</tr>
<tr>
<td>2015</td>
<td>200</td>
<td>97%</td>
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<tr>
<td>2016</td>
<td>100</td>
<td>96%</td>
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**Drill, Complete and Tie-in Costs**

- **Drilling Cost**
- **Completion Cost**
- **Actual vs AFE Drilling**
- **Actual vs AFE Completion**

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Cost ($MM)</th>
<th>Drilling Cost</th>
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<tr>
<td>2015</td>
<td>0.4</td>
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<tr>
<td>2016</td>
<td>0.2</td>
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**Fluid Type (# Wells)**

- **Foam**
- **Gelled Water**
- **Slickwater**

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<thead>
<tr>
<th>Year</th>
<th>Foam (# Wells)</th>
<th>Gelled Water (# Wells)</th>
<th>Slickwater (# Wells)</th>
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<td>2012</td>
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<tr>
<td>2015</td>
<td>40</td>
<td>80</td>
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</tr>
<tr>
<td>2016</td>
<td>50</td>
<td>100</td>
<td>120</td>
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**Proved has a higher concentration of Extended Reach Horizontals (reservoir exposure) which is reflected in the average well capital**


Note: All production values are raw oil and gas volumes collected from public sources and do not include any extracted natural gas liquids. Oil rates include condensate volumes which account for less than 1% of the total liquids. Data subset are wells Spud post Jan 1, 2014
Significant production variability with similar reservoir quality suggests execution is a key factor.
Provost Viking - Horizontal Type Curve Economics

**Horizontal Oil Type Curves Based on 2014 Onward Wells**

- Provost High IP; 1 Mile (n=45)
- Provost Med IP; 3/4 Mile (n=68)
- Provost Low IP; 1/2 Mile (n=153)

- 1 mile: IP30 98 bbl/d
- 3/4 mile: IP30 60 bbl/d
- 1/2 mile: IP30 47 bbl/d

**Type Curve Economic Results Summary**

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<th>0.5 mile</th>
<th>0.75 mile</th>
<th>1 mile</th>
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<tbody>
<tr>
<td>IP30 (bbl/d)</td>
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<td>86</td>
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<tr>
<td>EUR (Mboe)</td>
<td>51</td>
<td>65</td>
<td>101</td>
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<tr>
<td>GOR (scf/bbl)</td>
<td>6,200</td>
<td>6,200</td>
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<tr>
<td>CND Liquids Yield (bbl/MMcf)</td>
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<td>13</td>
<td>13</td>
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<tr>
<td>C3 - C4 Liquids Yield (bbl/MMcf)</td>
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<td>18</td>
<td>18</td>
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<tr>
<td>Capital (SM)</td>
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<td>$970</td>
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<td>Fixed Costs ($/well/month)</td>
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<td>Variable Oil Costs ($/bbl)</td>
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<td>Variable Gas Costs ($/MMcf)</td>
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<tr>
<td>Yr 1 Op cost ($/boe)</td>
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<td>$9.79</td>
<td>$9.46</td>
</tr>
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**3/4 Mile Type Curve Sensitivities**

- Rate of Return Sensitivity on Base Type Curve:
  - BT-NPV@10% ($M) | $180 | $300 | $680
  - IRR (%) | 33% | 38% | 64%
  - Payout (yrs) | 2.0 | 1.9 | 1.4
  - PII (@10%) | 0.3 | 0.4 | 0.7

**Key Points**

- The 1/2 mile, 3/4 mile and 1 mile horizontal type curves were developed from the average of 266 wells drilled since Jan 1, 2014.
- An average of 6,200 scf/bbl GOR was used however some wells have GOR significantly more than 10,000 scf/bbl.
- Resulting economics show increasing robust economics as lateral length increases at flat prices of C$2.50/GJ AECO and US$50/bbl WTI.
- The tornado plot above shows that economics are most sensitive to oil price, capital and well performance.

**Provost type curve economics show good IRRs at current pricing**

**Increasing the lateral length from 1/2 mile to 1 mile almost doubles the IRR**
What to watch for?

**Successful Development Strategies**

- **Horizontal development in previously thought to be only gas producing areas**
- **Downspacing - 200 m interwell spacing**
- **Horizontal Development in previously water flooded areas**
- **Longer lateral length increases economic IRR of play**

- Demand will continue to be strong in Western Canada for light oil with short cycle times and quick pay-back periods, particularly those operators with demonstrated running room

- While the Viking at both Dodsland and Provost were initially developed for natural gas more than 50 years ago, they have both proven to be prolific oil sources with cumulative production of more than 232 MMbbl and 70 MMbbl respectively*.

- Since Viking rights are widely held throughout the fairway, the only way to increase a position here is through consolidation. Expect to see increased A&D activity with Viking players.

- Dodsland appears to be reaching a plateau in terms of production so expect to see continued drilling with improved efficiency and techniques, but overall rates should remain relatively flat - this will encourage development at Provost.

- Capital deployment for Viking oil has been focused at Dodsland but recent successes at Provost have ensured increased future spending levels here.

- Provost will see a significant increase in oil production rates as multiple techniques are deployed. There will be hits and misses, but much like a game of “Battleship” when there is a successful “hit”, expect to see a focused use of certain techniques at different times and in different areas. In particular, look for longer laterals at Provost which increases reservoir exposure and maximizes overall delivery.

- This identified, large underdeveloped oil resource is why we think Viking players will be “Alberta Bound”

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*As of February 2017

**Material Viking oil production growth will be in Alberta**