## Agenda

<table>
<thead>
<tr>
<th>Time</th>
<th>Session</th>
<th>Speaker(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>9:05 - 9:20</td>
<td>Strategy Update</td>
<td>Asim Ghosh</td>
</tr>
<tr>
<td>9:20 - 9:30</td>
<td>Financial Plan</td>
<td>Alister Cowan</td>
</tr>
<tr>
<td>9:30 - 9:35</td>
<td>Portfolio Review</td>
<td>Rob Peabody</td>
</tr>
<tr>
<td>9:35 - 9:45</td>
<td>Heavy Oil</td>
<td>Ed Connolly</td>
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<tr>
<td>9:45 – 9:55</td>
<td>Western Canada</td>
<td>Rob Symonds</td>
</tr>
<tr>
<td>9:55 - 10:05</td>
<td>Downstream</td>
<td>Bob Baird</td>
</tr>
<tr>
<td>10:05 - 10:15</td>
<td>Q &amp; A</td>
<td>Rob Peabody, Ed Connolly, Rob Symonds, Bob Baird, Brad Allison</td>
</tr>
<tr>
<td>10:30 - 10:35</td>
<td>Portfolio Review</td>
<td>Rob Peabody</td>
</tr>
<tr>
<td>10:35 - 10:45</td>
<td>Asia Pacific</td>
<td>Bob Hinkel</td>
</tr>
<tr>
<td>10:45 - 10:55</td>
<td>Oil Sands</td>
<td>John Myer</td>
</tr>
<tr>
<td>10:55 - 11:05</td>
<td>Atlantic Region</td>
<td>Malcolm Maclean</td>
</tr>
<tr>
<td>11:05 - 11:15</td>
<td>Q &amp; A</td>
<td>Rob Peabody, Bob Hinkel, John Myer, Malcolm Maclean, Brad Allison</td>
</tr>
<tr>
<td>11:15 - 11:20</td>
<td>Wrap-up</td>
<td>Asim Ghosh, Rob Peabody, Alister Cowan</td>
</tr>
<tr>
<td>11:20 - 11:30</td>
<td>Q &amp; A</td>
<td>All</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Lunch</strong></td>
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</table>
Strategy and Portfolio Development

- Balanced growth strategy delivering
- Transforming the foundation
- Focused integration – achieving world market prices
- Delivering major projects
- Top-quartile dividend
- Reliable and repeatable performance improving returns
The Way We Were

**Near-Term**
- North Amethyst

**Mid-Term**
- Pikes Peak South

**Long-Term**
- Liwan 3-1
- Madura Strait BD
- Sunrise Energy Project
Rich Queue of Projects

**Near-Term (2014-2016)**
- Sandall Thermal
- Rush Lake Thermal
- Edam West Thermal
- Edam East Thermal
- Vawn Thermal
- South White Rose
- N. Amethyst Hibernia
- Sunrise Energy Project Phase 1
- Wapiti Cardium
- Ansell Cardium
- Ansell Wilrich
- Kaybob Duvernay
- Oungre Bakken
- Viking (various)
- Kakwa Wilrich
- Liwan 3-1
- Liuhua 34-2
- Toledo Recycle Gas Compressor
- Hardisty and Patoka Expansion

**Mid-Term (2017-2019)**
- Pikes Peak North Thermal
- Rush Lake 2 Thermal
- Lloyd 1 Thermal
- Lloyd 2 Thermal
- McMullen Thermal 1
- Heavy Oil Pipeline Expansion
- S.W. Sask. Multi-zone
- Lima Refinery Heavy Oil Project
- Liuhua 29-1
- West White Rose
- Sunrise Energy Project Phase 2A
- Rainbow Muskwa
- Sinclair Montney
- Kakwa Montney
- Madura BD
- Madura MDA
- Madura MBH

**Long-Term (2020+)**
- Lloyd 3 Thermal
- McMullen Thermals
- Sunrise Energy Project Phase 2B
- Bay du Nord
- Harpoon
- Mizzen
- Saleski
- Horn River Muskwa
- Wild River Duvernay
- White Rose Gas
- Heavy Oil Cold EOR
- Slater River NWT
- Sunrise Future Phases
- Five Indonesia Discoveries
- Graham Montney
- Cypress Montney
• On track to exceed 140% annual average through 2017

Values exclude economic revisions
Here’s what we mean by higher quality returns—predictable outputs, less volatility, and sustainable growth.

Here’s how we create it:

- Portfolio flexibility
- Balancing towards longer-wavelength projects
- Focused integration
- Shaping execution risk
- Oilier pricing
## Portfolio Flexibility

- **Broad portfolio**
- **Capital allocation**

**Near-Term (2014-2016)**
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- Edam East Thermal
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- South White Rose
- N. Amethyst Hibernia
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- Ansell Cardium
- Ansell Wilrich
- Kaybob Duvernay
- Oungre Bakken
- Viking (various)
- Kakwa Wilrich
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- Liuhua 34-2
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- Hardisty and Patoka Expansion

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- Sunrise Future Phases
- Five Indonesia Discoveries
- Graham Montney
- Cypress Montney
Balancing Towards Longer Wavelength Projects

- Long wavelength production includes Heavy Oil thermals, resource plays and Oil Sands
- Conventional production includes Atlantic, Western Canada conventional and Asia Pacific
Delivering Pricing Reliability

Realized Pricing on Upstream Production Processed (March 31, 2014)

- Heavy Oil
  - Realized Price: $127/bbl
  - Additional revenue/bbl: $51-$60
  - Increased operating netback/bbl: $38-$45
  - Production: 127 mbbl/d

- Western Canada Medium & Light
  - Realized Price: $100/bbl
  - Production: 55 mbbl/d

- Atlantic
  - Realized Price: $110/bbl
  - Production: 50 mbbl/d

- Wenchang
  - Realized Price: $120/bbl
  - Production: 9 mbbl/d

Brent Pricing Benchmark

Additional revenue/bbl: $51-$60
Increased operating netback/bbl: $38-$45
Shaping Execution Risk

Liwan Delivered

SeaRose Reliability

97% Refinery Uptime

Proven Thermal Performance

Room to Run at Ansell

Flemish Pass Discoveries
Oilier Pricing

- Commodity value
- Higher netback production
Shaping Risk and Delivering Higher Quality Returns

**Portfolio Flexibility**

**Longer Wavelength**

**Focused Integration**

**Higher Quality Returns**

**Sustainable Growth**

- **Near-Term (2014-2016)**
  - South White House
  - & Amsterdam Shelves
  - Sullust Energy Project Phase 1
  - Middle Dominant
  - Vital Energy
  - Market Access
  - veteran Discovery
  - Exmor 3.5
  - Express 24/2
  - Tekilo Aspari Gas Compressor
  - Flexibility and Market Experience

- **Mid-Term (2017-2019)**
  - Phka Tiger North Thermal
  - North Lake 2 Thermal
  - Long 1 Thermal
  - Lloyd 2 Thermal
  - Mitchell 2 Thermal
  - Phase Oil Pipes Expedition
  - 3.5. South. West area
  - L. Alparkebby North Oil Project
  - Lloyd 20-A
  - New/Klester
  - Sullust Energy Project Phase 2C
  - Rainbow Hydrates
  - Arabian Shelves
  - Kachemik South
  - Western MZ
  - Western USA

- **Long-Term (2020+)**
  - Lloyd 3 Thermal
  - Mitchell Shelves
  - Sullust Energy Project (Phase 2C
  - Bay du Nord
  - Naparte
  - Wacket
  - Ofsted
  - North Slope Bay
  - North Slope Bay
  - Whitehorse Gas
  - Rainy Oil Field
  - South Bone MZ
  - Southern California
  - Poole Inland Discoveries
  - In area Shelves
  - Canadian Shelves

**Conventional**

**Long Wavelength**

**North American Dry Gas**

**Oil and Oil-Like Pricing**

**Shaping Execution Risk**

**Oilier Pricing**

**Brent Pricing Benchmark**

- Lican Delivered
- SeaRose Reliability
- 97% Refinery Uptime
- Proven Thermal Performance
- Room To Run At Anseal
- Flexible Pass Discoveries
The Bottom Line – Returns

Total Shareholder Return – June 1, 2011 – June 1, 2014\(^1, 2\)

1. TSR Data Sourced from Bloomberg
2. As of June 1st, 2014. Peers include: Canadian Natural Resources, Cenovus, Encana, Imperial Oil, Suncor and Talisman
## On Pace With Our Targets

<table>
<thead>
<tr>
<th></th>
<th>2010 Actual</th>
<th>2013 Actual</th>
<th>Q1 2014</th>
<th>2012-2017 Targets</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production</strong> (mboe/d)</td>
<td>287</td>
<td>312</td>
<td>326</td>
<td>5 - 8% CAGR &lt;sup&gt;(3)&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>Cash Flow from Operations</strong> &lt;sup&gt;(3)&lt;/sup&gt;</td>
<td>$3.1 billion</td>
<td>$5.0 billion</td>
<td>$1.5 billion</td>
<td>6 - 8% CAGR &lt;sup&gt;(3)&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>Reserve Replacement Ratio</strong> &lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>184%</td>
<td>166%</td>
<td>N/A</td>
<td>&gt; 140% average</td>
</tr>
<tr>
<td><strong>Return on Capital in Use</strong> &lt;sup&gt;(2, 3)&lt;/sup&gt;</td>
<td>8.4%</td>
<td>12.6%</td>
<td>12.0%</td>
<td>14 - 15%</td>
</tr>
<tr>
<td><strong>ROCE</strong> &lt;sup&gt;2, 3&lt;/sup&gt;</td>
<td>6.4%</td>
<td>8.7%</td>
<td>8.0%</td>
<td>11 - 12%</td>
</tr>
</tbody>
</table>

<sup>(1)</sup> Excluding economic revisions
<sup>(2)</sup> Adjusted for after-tax impairments on property, plant and equipment of $204 million
<sup>(3)</sup> Non-GAAP measures

Please see advisory for further detail
Integration Strategy Mitigates Earnings Volatility

Upstream E&P Net Operating Earnings

1. After Tax and Excludes Impairments
2. Western Canada Select
Integration Strategy Mitigates Earnings Volatility

**Total Net Operating Earnings**

1. After-tax and excludes Impairments
2. Adjusted for FIFO impact
3. Western Canada Select
4. Infrastructure and Marketing
5. Impact of scheduled upgrader turnaround

Integration Strategy Mitigates Earnings Volatility

**Total Net Operating Earnings**

1. After-tax and excludes Impairments
2. Adjusted for FIFO impact
3. Western Canada Select
4. Infrastructure and Marketing
5. Impact of scheduled upgrader turnaround
Portfolio Management/Capital Allocation – Shaping Risk

- Product type
- Geography/markets
- Capital requirement/timeline
- Return of Asset/IRR
- Reserve life index
- Technology
- Execution risk

Production by Geography*

- Lloydminster
- Western Canada
- Atlantic Canada
- Asia Pacific

Production by Product Type*

- Light Medium & NGLs
- Heavy and Bitumen
- Natural Gas Canada
- Natural Gas Asia Pacific

* Per guidance issued Dec 11, 2013
Staying Course on Guidance

**Capital Expenditures (billions)**

- 2013 Actual: $5.0
- 2014 Guidance: $4.8 – $5.0

- 2013 cash outlay: $4.5 billion

**Production (mboe/day)**

- 2013 Actual: 312 mboe/d

- Forecast range: $4.8 – $5.0

* Midstream/Downstream/Corporate
* Atlantic Region
* Oil Sands/Sunrise
* Asia Pacific
* Heavy Oil
* Western Canada

* Natural Gas Asia (mboe/day)
* Natural Gas Canada (mboe/day)
* Light/Medium Oil and NGLs (mbbl/day)
* Heavy Oil and Bitumen (mbbl/day)
## Liquidity

<table>
<thead>
<tr>
<th></th>
<th>Q1 2014 Actual</th>
<th>Debt Targets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Debt</td>
<td>$2.7 bln</td>
<td>N/A</td>
</tr>
<tr>
<td>Net Debt to Cash Flow*</td>
<td>0.5 X</td>
<td>Below 1.5X</td>
</tr>
<tr>
<td>Net Debt to Capital</td>
<td>11%</td>
<td>Below 25%</td>
</tr>
</tbody>
</table>

* Using FY2013 Cash Flow

## Long-term Debt Maturity Schedule

<table>
<thead>
<tr>
<th>Year</th>
<th>CDN$ Millions</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>800</td>
</tr>
<tr>
<td>2015</td>
<td>200</td>
</tr>
<tr>
<td>2016</td>
<td>100</td>
</tr>
<tr>
<td>2017</td>
<td>200</td>
</tr>
<tr>
<td>2018</td>
<td>200</td>
</tr>
<tr>
<td>2019</td>
<td>1,000</td>
</tr>
<tr>
<td>2020</td>
<td>200</td>
</tr>
<tr>
<td>2021</td>
<td>200</td>
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<td>2022</td>
<td>400</td>
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<td>2024</td>
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<td>2035</td>
<td>200</td>
</tr>
<tr>
<td>2036</td>
<td>200</td>
</tr>
<tr>
<td>2037</td>
<td>200</td>
</tr>
</tbody>
</table>
Focus on Returns

• Strong balance sheet to see long-lead projects through commodity price fluctuations
• Portfolio management and flexible capital allocation
• Reliable cash flow growth
• Top-quartile dividend
Foundation Portfolio Review
Rob Peabody
Critical & Serious Incidents \(^1\)

Total Recordable Incident Rate \(^2\)

1 Critical and Serious Incidents includes process and occupational safety

2 TRIR is a calculated value based on lost-time, restricted work and medical aid incidents
## Near-Term (2014-2016)

<table>
<thead>
<tr>
<th>Project</th>
<th>Forecast Net Production Adds (BOE/D)</th>
<th>Forecast Net Capex</th>
<th>Forecast IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Heavy Oil Thermals</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Four sanctioned projects</td>
<td></td>
<td></td>
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<tr>
<td><strong>Western Canada</strong></td>
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<td></td>
<td></td>
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<tr>
<td>Resource plays (various)</td>
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<td></td>
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</tr>
<tr>
<td><strong>Downstream</strong></td>
<td></td>
<td></td>
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<tr>
<td>Toledo Hydrotreater Recycle</td>
<td></td>
<td></td>
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<tr>
<td>Gas Compressor Project</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hardisty and Patoka</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>expansion</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>33,500</td>
<td>~$1.3 bln</td>
<td>&gt;20%</td>
</tr>
<tr>
<td></td>
<td>20,000</td>
<td>~$1.0 bln</td>
<td>&gt;15%</td>
</tr>
<tr>
<td></td>
<td>N/A</td>
<td>~$20 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td></td>
<td>N/A</td>
<td>~$300 mm</td>
<td>&gt;20%</td>
</tr>
</tbody>
</table>

## Mid-Term (2017-2019)

<table>
<thead>
<tr>
<th>Project</th>
<th>Forecast Net Production Adds (BOE/D)</th>
<th>Forecast Net Capex</th>
<th>Forecast IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Heavy Oil Thermals</strong></td>
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<tr>
<td>Five identified projects</td>
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<tr>
<td><strong>Western Canada</strong></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Resource plays (various)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Downstream</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heavy Oil pipeline expansion</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lima Refinery crude flexibility project</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>37,000</td>
<td>~$1.0 bln</td>
<td>&gt;20%</td>
</tr>
<tr>
<td></td>
<td>20,000</td>
<td>~1.0 bln</td>
<td>&gt;15%</td>
</tr>
<tr>
<td></td>
<td>N/A</td>
<td>~$200 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td></td>
<td>N/A</td>
<td>~$300 mm</td>
<td>&gt;20%</td>
</tr>
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</table>

### Foundation Facelift

![Foundation Facelift Chart](chart.png)

**2014-2019 Expected Production**

- WC Conventional
- Resource Plays
- Heavy Oil

**Longer Wavelength**
Lengthening the Stride in our Foundation

- Longer wavelength
- Deep portfolio of high-return projects
- Competitively advantaged

![2014-2019 Expected Production Chart]

- WC Conventional
- Resource Plays
- Heavy Oil

Longer Wavelength
Heavy Oil
Ed Connolly
Heavy Oil Advantage

- Second-to-none land and infrastructure position
- Over two million net acres
- Technology fuelling growth
- Fully integrated
- Improved quality of returns
Making Long Wavelengths Longer

- Higher recoveries
- Higher netbacks

**FY2013 Netbacks/bbl**

<table>
<thead>
<tr>
<th></th>
<th>Thermal</th>
<th>Non-Thermal</th>
</tr>
</thead>
<tbody>
<tr>
<td>$/BOE</td>
<td>60</td>
<td>30</td>
</tr>
</tbody>
</table>

**Proportion of Thermal vs. Non-Thermal Production**

- **Full Year 2009**
  - Thermal: 10%
  - Non-Thermal: 90%

- **2014 Q1**
  - Thermal: 15%
  - Non-Thermal: 85%

- **2019 Forecast**
  - Thermal: 20%
  - Non-Thermal: 80%

**Op Cost/bbl**

<table>
<thead>
<tr>
<th></th>
<th>Thermal</th>
<th>Non-Thermal</th>
</tr>
</thead>
<tbody>
<tr>
<td>$/BOE</td>
<td>15</td>
<td>30</td>
</tr>
</tbody>
</table>

*Please see advisories for description of Netbacks*
## Thermal Production Forecast*

![Graph showing Thermal Production Forecast](image)

<table>
<thead>
<tr>
<th>Thermal Project</th>
<th>First Oil Date</th>
<th>Current/Forecasted Net Production Rate</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pikes Peak</td>
<td>1984</td>
<td>4,100</td>
<td>Producing</td>
</tr>
<tr>
<td>Bolney Celtic</td>
<td>1996</td>
<td>19,000</td>
<td>Producing</td>
</tr>
<tr>
<td>Paradise Hill</td>
<td>2012</td>
<td>4,500</td>
<td>Producing</td>
</tr>
<tr>
<td>Pikes Peak South</td>
<td>2012</td>
<td>12,000</td>
<td>Producing</td>
</tr>
<tr>
<td>Rush Lake pilot</td>
<td>2012</td>
<td>1,400</td>
<td>Producing</td>
</tr>
<tr>
<td>Sandall</td>
<td>2014</td>
<td>5,200</td>
<td>Producing</td>
</tr>
<tr>
<td>Rush Lake Commercial Ph 1</td>
<td>2015</td>
<td>10,000</td>
<td>Near-Term</td>
</tr>
<tr>
<td>Edam West</td>
<td>2016</td>
<td>3,500</td>
<td>Near-Term</td>
</tr>
<tr>
<td>Edam East</td>
<td>2016</td>
<td>10,000</td>
<td>Near-Term</td>
</tr>
<tr>
<td>Vawn</td>
<td>2016</td>
<td>10,000</td>
<td>Near-Term</td>
</tr>
<tr>
<td>Pikes Peak North</td>
<td>2016</td>
<td>3,500</td>
<td>Mid-Term</td>
</tr>
<tr>
<td>Rush Lake Commercial Ph 2</td>
<td>2017 - 2019</td>
<td>10,000</td>
<td>Mid-Term</td>
</tr>
<tr>
<td>Lloyd Thermal 1</td>
<td>2017 - 2019</td>
<td>10,000</td>
<td>Mid-Term</td>
</tr>
<tr>
<td>Lloyd Thermal 2</td>
<td>2017 - 2019</td>
<td>3,500</td>
<td>Mid-Term</td>
</tr>
<tr>
<td>McMullen Thermal 1</td>
<td>2017 - 2019</td>
<td>10,000</td>
<td>Mid-Term</td>
</tr>
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* Excludes Tucker
## Typical Thermal Economics

<table>
<thead>
<tr>
<th>Metric</th>
<th>Target ¹</th>
</tr>
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<tbody>
<tr>
<td>Construction time</td>
<td>~2 years</td>
</tr>
<tr>
<td>Start up to peak production</td>
<td>&lt; 3 months</td>
</tr>
<tr>
<td>SOR target</td>
<td>2.0 early years</td>
</tr>
<tr>
<td>Sustaining capital/bbl²</td>
<td>$5 - $7</td>
</tr>
<tr>
<td>Life of project</td>
<td>15 Years +</td>
</tr>
<tr>
<td>Recoveries target</td>
<td>&gt;50%</td>
</tr>
<tr>
<td>Operating cost per bbl</td>
<td>~$10 for first 2 years</td>
</tr>
<tr>
<td>IRR</td>
<td>&gt;20%</td>
</tr>
</tbody>
</table>

¹. Based on actual results as of March 31, 2013
². Non-GAAP measure, please see advisories
Leveraging Thermal Expertise at McMullen

- Best estimate contingent resources of 644 mmbbls*
- Development
  - Build on Heavy Oil expertise
  - Several 10,000 bpd projects
- Timeline
  - One project in mid-term
  - Several others in long-term

*Please see appendix
Horizontal wells
- Currently producing 13,000 bpd
- 140 drills per year
- Waterflood targeting 15% recovery

Cold Solvent EOR Process
- Targeting old CHOPS reservoirs
- Uses existing wells and infrastructure
- Early success
Delivering Higher Quality Returns

- Second-to-none land and infrastructure
- Technology fuelling growth
- Fully integrated
- Improved quality of returns

Forecast Net Production

2013 Thermal Netback*: ~$47.00
2013 Non-Thermal Netback*: ~$33.00

*MBOE/D

*Please see advisory for description of netbacks
Western Canada
Rob Symonds
Old Dog, New Tricks

- Extensive resource play portfolio diversified by product, region and scale
- Investing in the right projects
- Breaking down silos to improve efficiencies
Shaping the Resource Play Portfolio

- Disciplined capital allocation
- Average well cost reduction of ~30% over last three years
- Large portfolio allows flexibility
- > 1,500 locations on established resource plays
- Improving cycle time
Ansell – Room to Run

- Large land base
- Multi-zone potential: > 800 locations
- Fully scalable
The “Sweet Spot” – Kaybob Duvernay

• Four-well pad and two-well pad onstream
• High condensate yields of > 200 bbls/mmcf
• Early results encouraging
• Reducing costs

**Q1 2014 Kaybob Duvernay Products**

- Condensate: 44.8%
- NGL: 12.6%
- Gas: 42.6%

**Q1 2014 Kaybob Duvernay Revenue**

- Condensate: 68.5%
- NGL: 7.6%
- Gas: 24.0%
Other Mid-Term Potential

Rainbow Muskwa
- > 300,000 net developable acres
- Oil and liquids rich gas potential
- Assessing effectiveness of different fracs

S.W. Saskatchewan multi-zone
- > 140,000 acres
- Oil potential
- Not yet tested
Focus on Higher Quality Returns

- Extensive resource play portfolio diversified by production, region and scale
- Investing in the right projects
- Breaking down silos to improve efficiencies

*Please see advisories for description of netbacks*
Downstream
Bob Baird
<table>
<thead>
<tr>
<th>Project</th>
<th>Scope</th>
<th>Forecast Net Capex</th>
<th>Forecast IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Near-Term (2014-2016)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Toledo Hydrotreater Recycle Gas Compressor Project</td>
<td>Improve operational integrity and plant performance</td>
<td>~$20 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>Hardisty and Patoka expansion</td>
<td>Expand tankage and blending</td>
<td>~$300 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td><strong>Mid-Term (2017-2019)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lima Crude Flexibility Project</td>
<td>40 mbbls/d of heavy through modification of existing coker</td>
<td>~$300 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>Heavy Oil Pipeline System</td>
<td>Grow gathering system to accommodate new Husky thermal and third-party production</td>
<td>~$200 mm</td>
<td>&gt;20%</td>
</tr>
</tbody>
</table>
Strong Downstream Infrastructure Position

(1) Source: Solomon Associates
Strong Downstream Infrastructure Position

Transportation Fuel Production Cost – Top Quartile Ranking
2012 Study – Worldwide

(1) Source: Solomon Associates
Strong Downstream Infrastructure Position
Strong Downstream Infrastructure Position
Strong Downstream Infrastructure Position
Strong Downstream Infrastructure Position
Stabilize Cash Flow and Improve Returns

- Integrated on a barrel for barrel basis
- Reduces cash flow volatility
- Strong returns generated over last three years

**Total Net Operating Earnings**

1. After-tax and excludes Impairments
2. Adjusted for FIFO impact
3. Western Canada Select
4. Infrastructure and Marketing
5. Impact of scheduled upgrader turnaround
<table>
<thead>
<tr>
<th>Project</th>
<th>Forecast Net Production (boe/d)</th>
<th>Forecast Net Capex</th>
<th>Forecast IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Near-Term (2014-2016)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Asia Pacific</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liuhua 34-2</td>
<td>3,300</td>
<td>~$100 mm</td>
<td>&gt;15%</td>
</tr>
<tr>
<td>Oil Sands</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sunrise Phase 1</td>
<td>30,000</td>
<td>~$1.4 bln</td>
<td>11-13%</td>
</tr>
<tr>
<td>Atlantic Region</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>South White Rose</td>
<td>(Peak) 15,000</td>
<td>~$800 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>N. Amethyst Hibernia well</td>
<td>(Peak) 5,000</td>
<td>~$100 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td><strong>Mid-Term (2017-2019)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Asia Pacific</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liuhua 29-1</td>
<td>8,000-16,000(^1)</td>
<td>~$600 mm</td>
<td>&gt;15%</td>
</tr>
<tr>
<td>Madura (MDA, BD, MBH)</td>
<td>17,000</td>
<td>~$500 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>Oil Sands</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sunrise Phase 2A</td>
<td>35,000</td>
<td>~$1.6 bln (^2)</td>
<td>12-14%</td>
</tr>
<tr>
<td>Atlantic</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>West White Rose</td>
<td>(Peak) 25,000</td>
<td>~$2.8 bln</td>
<td>&gt;20%</td>
</tr>
<tr>
<td><strong>Long-Term (2020+)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Asia Pacific</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Five Indonesia discoveries</td>
<td>TBD</td>
<td>TBD</td>
<td>TBD</td>
</tr>
<tr>
<td>Oil Sands</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sunrise Phase 2B</td>
<td>35,000</td>
<td>~$1.6 bln (^2)</td>
<td>12-14%</td>
</tr>
<tr>
<td>Atlantic Region</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Flemish Pass</td>
<td>TBD</td>
<td>TBD</td>
<td>TBD</td>
</tr>
</tbody>
</table>

\(^1\) Subject to final gas sales agreement

\(^2\) 2013 dollars
Hitting Our Stride

- Strong pipeline of projects with good returns
- Major identified potential for the future
- Longer wavelength

Forecast Net Production

- Asia Pac
- Atlantic
- Oil Sands
Crossing the Threshold

- Material cash flow
- Focused portfolio
- Long track record in region

<table>
<thead>
<tr>
<th>Project</th>
<th>Current/Forecast Net Production (boe/d)</th>
<th>Forecast Net Capex</th>
<th>Forecast IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected 2014 Average Production</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wenchang</td>
<td>~5,000</td>
<td>~30,000</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>Liwan 3-1</td>
<td></td>
<td>-</td>
<td>~15%</td>
</tr>
<tr>
<td>Near-Term (2014-2016)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liuhua 34-2</td>
<td>3,300</td>
<td>~$100 mm</td>
<td>~15%</td>
</tr>
<tr>
<td>Mid-Term (2017-2019)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liuhua 29-1</td>
<td>8,000-16,000</td>
<td>~$600 mm</td>
<td>~15%</td>
</tr>
<tr>
<td>Madura Strait developments (MDA, BD, MBH)</td>
<td>17,000</td>
<td>~$550 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>Long-Term (2020+)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Indonesian Discoveries</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MDK</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>MAC</td>
<td>–</td>
<td>–</td>
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</tr>
<tr>
<td>MAX</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>MBJ</td>
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<td>–</td>
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</tr>
<tr>
<td>MBF</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
</tbody>
</table>

1 Subject to final gas sales agreement
Liwan Gas Project Delivered

- $6.5 billion project for three fields
  - Largest offshore platform in Asia; 1 bcf/d gas terminal
- About seven years from discovery to production
- Producing gas and liquids

Liwan 3-1 deepwater facilities

Offshore platform

Onshore gas terminal
Indonesian Discoveries & Developments

• BD field in construction
  • Net production of 40 mmcf/d gas and 2,400 boe/d liquids (2017F)

• MDA and MBH fields in tender phase
  • Net production of 50 mmcf/d (2017/18F)
The Next Chapter

- Exploration blocks
  - Madura exploration
  - Anugerah PSC
  - Offshore Taiwan
- Leveraging our expertise
- Assessing other opportunities
Focused Portfolio

- Material cash flow
- Strong queue of higher return projects
- Established track record

Forecast Net Production (includes cost recovery)
Predictable Earnings and Cash Flow

- 40-60 year project life
- Paced growth with huge upside
- Technology reducing sustaining capital and operating costs
- Integrated with Downstream

<table>
<thead>
<tr>
<th>Project</th>
<th>Forecast Net Production (boe/d)</th>
<th>Forecast Net Capex</th>
<th>Forecast IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Near-Term (2014-2016)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sunrise Phase 1</td>
<td>30,000</td>
<td>~$1.4 bln</td>
<td>11-13%</td>
</tr>
<tr>
<td>Mid-Term (2017-2019)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sunrise Phase 2A</td>
<td>35,000</td>
<td>~$1.6 bln</td>
<td>12-14%</td>
</tr>
<tr>
<td>Long-Term (2020+)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sunrise Phase 2B</td>
<td>35,000</td>
<td>~$1.6 bln</td>
<td>12-14%</td>
</tr>
<tr>
<td>Saleski</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Sunrise Future Development</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

1 2013 dollars
### Sunrise Phase 1 By The Numbers

<table>
<thead>
<tr>
<th>Metric</th>
<th>Target</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (net)</td>
<td>30,000 bbls/d</td>
</tr>
<tr>
<td>Start up to full production</td>
<td>18-24 Months</td>
</tr>
<tr>
<td>SOR design rate</td>
<td>3.0</td>
</tr>
<tr>
<td>Sustaining capital per bbl</td>
<td>~$8</td>
</tr>
<tr>
<td>Life of project</td>
<td>40-60 years</td>
</tr>
<tr>
<td>Operating cost per bbl</td>
<td>~$16-18</td>
</tr>
</tbody>
</table>

1 Non-GAAP measure, please see advisories
Sustaining Capital Protecting Returns

- Two-thirds of the cost of a major oil sands project like Sunrise is sustaining capital

- Evaluating more than 75 technologies to drive down costs, including:
  - Vacuum-insulated tubing
  - Custom rig design
  - Less steel, more modularization

![Vacuum-insulated Tubing](image_url)
Well Pad
Sunrise Phase 2 – Making Big Projects Smaller

- Phase 2A scheduled for end of decade; Phase 2B about two years later
- Greater modularity
- Reduced plant footprint
- Leveraging existing facilities and equipment
- Greater cost savings
Further Upside at Sunrise

- ~60 square kilometres of 3D seismic program shot
- 209 stratigraphic wells completed
- Thick reservoir
- Potential for further development on lease beyond existing approvals
• 10 billion barrels best estimate contingent resources\(^1\)

• Filed regulatory pilot project application

• Infrastructure in place and being developed

• Growth potential for the 2020s

\(^1\) Please see appendix
Longer Wavelength Business

• 40 – 60 year project life
• Annuity-type production
• Paced development with upside potential
• Technology reducing sustaining capital and operating costs
• Integrated with Downstream
Atlantic Region
Malcolm Maclean
White Rose – A Deep Portfolio

- High netback barrels
- Production and cash flow through the 2020s
- New growth driven by Bay du Nord

<table>
<thead>
<tr>
<th>Project</th>
<th>Forecast Net Peak Production (boe/d)</th>
<th>Forecast Net Capex</th>
<th>Forecast IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Near-Term (2014-2016)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>North Amethyst Hibernia well</td>
<td>5,000</td>
<td>~$100 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>South White Rose Extension</td>
<td>15,000</td>
<td>~$800 mm</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>Mid-Term (2017-2019)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>West White Rose</td>
<td>25,000</td>
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<td>&gt;20%</td>
</tr>
<tr>
<td>Long-Term (2020+)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Flemish Pass</td>
<td>400 million bbls (gross) best estimate contingent resource&lt;sup&gt;1&lt;/sup&gt;</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bay du Nord</td>
<td>In delineation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Harpoon</td>
<td>130 million bbls (gross) best estimate contingent resource&lt;sup&gt;1&lt;/sup&gt;</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mizzen</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<sup>1</sup> Please see appendix. Husky has a 35% interest in the gross resources.
• Achieves two objectives:
  • Significant cost savings over standalone gas injection
  • Improves recoverability
• First gas injection Q1 2014, first oil around the end of the year
• Pairing gas injection and oil production improves returns > 20%
West White Rose Improving Drilling Efficiency

- SeaRose FPSO processing reduces overall project cost
- Wellhead platform designed to facilitate other tie-backs
- Sanction upon development plan approval
• Employing established technologies in innovative ways to enhance returns
• West Mira custom-built to future needs
• Five-year renewable lease
• Multiple targets identified
• West Hercules drilling rig secured
• 18-month drilling campaign starting in Q3 2014
• Balancing exploration against development

Map courtesy of Statoil
Generating Cash Flow and Growth

- Near and medium-term projects staged to fund future growth and provide dependable cash flow
- Long-term commercial potential in Flemish Pass

Net Production

- South White Rose
- West White Rose
- North Amethyst
- White Rose
- Terra Nova

Flemish Pass
**Balanced Growth Strategy Is Delivering**

- Expansive growth portfolio
- Higher quality returns
- Hitting five-year targets
- Top-quartile dividend

### Near-Term (2014-2016)
- Sandall Thermal
- Rush Lake Thermal
- Edam West Thermal
- Edam East Thermal
- Vawn Thermal
- South White Rose
- N. Amethyst Hibernia
- Sunrise Energy Project Phase 1
- Wapiti Cardium
- Ansell Cardium
- Ansell Wilrich
- Kaybob Duvernay
- Oungre Bakken
- Viking (various)
- Kakwa Wilrich
- Liwan 3-1
- Liuhua 34-2
- Toledo Recycle Gas Compressor
- Hardisty and Patoka Expansion

### Mid-Term (2017-2019)
- Pikes Peak North Thermal
- Rush Lake 2 Thermal
- Lloyd 1 Thermal
- Lloyd 2 Thermal
- McMullen Thermal 1
- Heavy Oil Pipeline Expansion
- S.W. Sask. Multi-zone
- Lima Refinery Heavy Oil Project
- Liuhua 29-1
- West White Rose
- Sunrise Energy Project Phase 2A
- Rainbow Muskwa
- Sinclair Montney
- Kakwa Montney
- Madura BD
- Madura MDA
- Madura MBH

### Long-Term (2020+)
- Lloyd 3 Thermal
- McMullen Thermals
- Sunrise Energy Project Phase 2B
- Bay du Nord
- Harpoon
- Mizzen
- Saleski
- Horn River Muskwa
- Wild River Duvernay
- White Rose Gas
- Heavy Oil Cold EOR
- Slater River NWT
- Sunrise Future Phases
- Five Indonesia Discoveries
- Graham Montney
- Cypress Montney
Final Q & A
Forward-Looking Statements and Information

Certain statements in this document are forward-looking statements and information (collectively “forward-looking statements”), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this document include, but are not limited to, references to:

• with respect to the business, operations and results of the Company generally: the Company’s general strategic plans and growth strategies; the Company’s near, mid and long-term queue of projects; forecast “long-wavelength” and conventional production as percentages of total production by 2019; projected product pricing mix as a percentage of past and forecast production through 2019; anticipated reserve replacement ratio through 2017; 5-year targets for production, cash flow from operations, reserve replacement ratio, return on capital in use, and return on capital employed; proportions of expected production by geographic region and product type for 2014-2019, the Company’s 2014 capital expenditure and production guidance; the Company’s target net debt to cash flow and net debt to capital for 2012 - 2017; forecast near-term and mid-term net production adds, net capital expenditure and IRR from projects in the Company’s Heavy Oil Thermal, Western Canada and Downstream properties; proportions of expected production from conventional, resource plays and heavy oil through 2019; proportions of expected production from conventional oil, conventional gas and resource plays through 2019; forecast near, mid and long-term net production, net capital expenditure and IRR from projects in the Company’s Asia Pacific, Oil Sands and Atlantic regions; and volumes and proportions of expected production from projects in the Company’s Asia Pacific, Oil Sands and Atlantic regions through 2019 and beyond;

• with respect to the Company’s Asia Pacific Region: forecast 2014 average, near, mid and long-term net production, net capital expenditure and IRR from projects in the Company’s Asia Pacific Region; anticipated timing and volumes of production from the Company’s Madura BD, MDA and MBH fields ; the Company’s future exploration plans in the Asia Pacific Region; volumes and proportions of expected production from the Company’s Asia Pacific Region projects through 2019; and anticipated time frame for production from the Company’s Liuhua 34-2 and Liuhua 29-1 gas fields and gross production capacity

• with respect to the Company’s Atlantic Region: forecast near, mid, and long-term net peak production, net capital expenditure and IRR from the Company’s Atlantic Region projects; expectations for production and cash flow through the 2020s; anticipated timing of first oil from the Company’s South White Rose project; expected improvement in returns resulting from pairing of gas injection and oil production at the South White Rose developments; expectations regarding sanctioning of the West White Rose project; exploration and drilling plans in the Company’s Atlantic Region; anticipated growth and cash flow resulting from the Company’s near and medium-term projects in the region; anticipated long-term commercial potential in the Flemish Pass area; and volumes and proportions of expected production from the Company’s Atlantic Region projects through 2019 and beyond;

• with respect to the Company’s Oil Sands properties: anticipated life span of projects in the region; forecast near, mid and long-term net production, net capital expenditure and IRR from the Company’s Oil Sands projects; targets for net production, timing of startup to full production, SOR design rate, sustaining capital per bbl, life of project, , and operating cost per bbl at Phase 1 of the Company’s Sunrise Energy Project; scheduled timing of completion of phase 2A and phase 2B of the Company’s Sunrise Energy Project; anticipated development potential at the Company’s Sunrise Energy Project and other oil sands properties; anticipated long-term growth potential in the Company’s Saleski area; and forecast net production from the Company’s Sunrise Energy Project through 2019 and beyond;
Advisories

- with respect to the Company's Western Canadian oil and gas plays: mid-term exploration and development potential at specified plays; estimated time to drill at specified plays; estimated well costs at specified plays; estimated net resource potential and potential EUR/well at the Company's oil resource and gas resource plays;

- with respect to the Company's Heavy Oil properties: 2019 forecast mix of thermal and non-thermal production; estimated timing and volume of production growth from the Company's thermal projects; estimated timing of first oil and estimated production rates from the Company's slate of thermal projects; estimated thermal production economics; and anticipated proportion of net production from CHOPS, horizontal drilling, Cold EOR, thermal production and the Company's McMullen project through 2019; and

- with respect to the Company's Downstream operating segment: forecast near-term and mid-term scope, net capital expenditure and IRR from projects in the Company's Downstream operating segment.

In addition, statements relating to "reserves" and "resources" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and resources and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserve, resource and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky.

The Company's Annual Information Form for the year ended December 31, 2013 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.
Non-GAAP Measures

This document contains certain terms which do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of net operating earnings and cash flow from operations, there are no comparable measures to these non-GAAP measures in accordance with IFRS. These non-GAAP measurements are considered to be useful as complementary measurements in assessing Husky's financial performance, efficiency and liquidity, but may not be appropriate for other purposes. These terms include:

Cash Flow from Operations, which should not be considered an alternative to, or more meaningful than "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Cash flow from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation expense, deferred income taxes, foreign exchange, gain or loss on sale of assets and other non-cash items.

($ millions)    2010  2013  Q1 2014
GAAP cash flow – operating activities  2,222  4,645  1,336
Settlement of asset retirement obligations  60  142  49
Income taxes paid   784  433  96
Change in non-cash working capital   7  21  58
Non-GAAP cash flow from operations  3,072  5,222  1,536

Compound Annual Growth Rate ("CAGR") measures the year-over-year growth rate over a specified period of time. CAGR is presented in Husky's financial reports to assist management in analyzing longer-term performance. CAGR is calculated by taking the nth root of the total percentage growth rate, where n is the number of years in the period being considered.

Return on Capital Employed ("ROCE") measures the return earned on long-term capital sources such as long term liabilities and shareholder equity. ROCE is presented in Husky's financial reports to assist management in analyzing shareholder value. ROCE equals net earnings plus after-tax finance expense divided by the two-year average of long term debt including long term debt due within one year plus shareholders' equity. Return on capital employed was adjusted for an after-tax impairment charge on property, plant and equipment of $204 million for the year ended December 31, 2013. Return on capital employed, based on the calculation used in prior periods for the year ended December 31, 2013, was 7.9%.

Return on Capital in Use ("ROCU") measures the return earned on those portions of long-term capital sources such as long term liabilities and shareholder equity that are currently generating cash flows. ROCU is presented in Husky's financial reports to assist management in analyzing shareholder value and return on capital. ROCU equals net earnings plus after-tax interest expense divided by the two-year average of long term debt including long term debt due within one year plus shareholders' equity less any capital invested in assets that that are not generating cash flows. Return on capital in use was adjusted for an after-tax impairment charge on property, plant and equipment of $204 million for the year ended December 31, 2013. Return on capital in use based on the calculation used in prior periods for the year ended December 31, 2013 was 11.3%.

Return on Equity is used to assist in analyzing shareholder value. Return on equity equals net earnings divided by the two-year average shareholders' equity.

Sustaining capital on a per unit basis is calculated as annual capital expenditures divided by plant design throughput.

Operating netback assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. The operating netback was determined as realized price less royalties, operating costs and transportation on a per unit basis.
Disclosure of Oil and Gas Information

Unless otherwise stated, reserve and resource estimates in this document have an effective date of December 31, 2013 and represent Husky’s share. Unless otherwise noted, historical production numbers given represent Husky’s share.

The Company uses the terms barrels of oil equivalent (“boe”), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

Reserve replacement ratios for a given period are determined by taking the Company’s incremental proved reserve additions for that period divided by the Company’s upstream gross production for the same period. Forecast reserve replacement ratios for a given period are calculated by taking the forecast proved reserve additions for those periods divided by the forecast gross production for the same periods.

The Company has disclosed possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of proved plus probable plus possible reserves. There is a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. The Company has disclosed its total reserves in Canada in its Annual Information Form for the year ended December 31, 2013, which reserves disclosure is incorporated by reference herein.

The Company has disclosed best-estimate contingent resources in this document. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Best estimate as it relates to resources is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Estimates of contingent resources have not been adjusted for risk based on the chance of development. There is no certainty as to the timing of such development. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling for unrisked contingent resources; (ii) regulatory approvals; and (iii) Company and partner approvals to proceed with development.

Specific contingencies preventing the classification of contingent resources at the Company’s Atlantic Region discoveries as reserves include additional exploration and delineation drilling, well testing, facility design, preparation of firm development plans, regulatory applications, company and partner approvals. Positive and negative factors relevant to the estimate of Atlantic Region resources include water depth and distance from existing infrastructure.
Disclosure of Oil and Gas Information cont’d

Specific contingencies preventing the classification of contingent resources at the Company’s oil sands properties as reserves include further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and company approvals. Development is also contingent upon successful application of SAGD and/or Cyclic Steam Stimulation (CSS) technology in carbonate reservoirs at Saleski, which is currently under active development. Positive and negative factors relevant to the estimate of oil sands resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density. The Company has disclosed best estimate contingent resources in the tables on slide 96. The economic portion of these contingent resources is 10,952.4 mmboe and the uneconomic portion is 1,819.4 mmboe.

Specific contingencies preventing the classification of contingent resources at the Company’s McMullen properties as reserves include further geological and reservoir studies, seismic data acquisition and evaluation, exploration and delineation drilling, facility design, reservoir performance, preparation of firm development plans, regulatory applications and company approvals. Positive and negative factors relevant to the estimate the oil sands resources include a higher level of uncertainty in the estimates as a result of variability in well distribution and depths across the area and regional trends in reservoir quality.

Specific contingencies preventing the classification of contingent resources at the Company’s heavy oil properties as reserves include further geological and reservoir studies, seismic data acquisition and evaluation, exploration and delineation drilling, facility design, reservoir performance, preparation of firm development plans, regulatory applications and company approvals. Some development is also contingent upon successful development and application of enhanced oil recovery technologies in post-CHOPS reservoirs, and reservoir response in waterflood projects. Positive and negative factors relevant to the estimate of heavy oil resources include a higher level of uncertainty in the estimates as a result of variability in well distribution and depths across the area and regional trends in reservoir quality.

Specific contingencies preventing the classification of contingent resources in the Company’s Western Canada resource plays as reserves include required improvement in gas prices, optimization of drilling and completion design to further reduce costs, preparation of firm developments plans, timing of development and Company approvals. Positive and negative factors relevant to the estimate of Western Canada resource play resources include a higher level of uncertainty in the estimates as a result of lower number of wells and limited production history. Total reserves estimates for Ansell are provided. This is a total of proved, probable and possible reserves. The 150 million boe of reserves (net) are comprised of Proved: 113 million boe, Probable: 19 million boe and Possible: 18 million boe.

Specific contingencies preventing the classification of contingent resources at the Company’s Asia Pacific region discoveries as reserves include additional exploration and delineation drilling, well testing, facility design, preparation of firm development plans, regulatory applications, company and partner approvals. Positive and negative factors relevant to the estimate of Asia Pacific resources include water depth and distance from existing infrastructure.
Note to U.S. Readers

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, "Standards of Disclosure for Oil and Gas Disclosure", adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it uses certain terms in this document, such as "possible reserves" and "best estimate contingent resources" that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.
All currency is expressed in Canadian dollars unless otherwise directed.
## Reserves Breakdown: Foundation Portfolio

All figures as of Dec 31, 2013

<table>
<thead>
<tr>
<th>Project</th>
<th>WI Proved MMBOE</th>
<th>W-I Probable MMBOE</th>
<th>WI-Possible MMBOE</th>
<th>WI Contingent Resources Best Estimate MMBOE</th>
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<tr>
<td><strong>Heavy Oil</strong></td>
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<td>Non-Thermal (total)</td>
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<td>40.1</td>
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<tr>
<td>Thermal (existing)</td>
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<td>Rush lake</td>
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<td>Edam West</td>
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<td>-</td>
<td>-</td>
<td>23.4</td>
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<td>Edam East</td>
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<td>41.2</td>
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<td>Vawn</td>
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<td>Prince</td>
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<td>Dee Valley</td>
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<td>19.1</td>
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<td>Kimino</td>
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<tr>
<td>Triangle Thermal</td>
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<td>-</td>
<td>13.7</td>
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<td>Lloyd Thermal</td>
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<td>Beaverdam Thermal</td>
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<td>Tucker</td>
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<td><strong>Western Canada</strong></td>
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<td>Conventional Oil and Gas</td>
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<td>Oil</td>
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<td>Butte Lower Shaunavon</td>
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<td>Oungre Bakken</td>
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<td>Wapiti Cardium</td>
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<td>Viking (various)</td>
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<td>Kakwa</td>
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<td>0.1</td>
<td>-</td>
<td>0</td>
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<td>Gas</td>
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<td>Ansell Multi-zone</td>
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<td>Kaybob South Duvernay</td>
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<td>Bivouac Jean Marie</td>
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<td>Kakwa other zones</td>
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<td>Sinclair Montney (North &amp; South)</td>
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<td>-</td>
<td>64.8</td>
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<td>Wild River Duvernay</td>
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<td>-</td>
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<tr>
<td>Slater River Canol</td>
<td>-</td>
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### Reserves Breakdown: Pillars Portfolio

All figures as of Dec 31, 2013

<table>
<thead>
<tr>
<th>Project</th>
<th>Working Interest Proved MMBOE</th>
<th>Working Interest Probable MMBOE</th>
<th>Working Interest Possible MMBOE</th>
<th>Contingent Resources Best Estimate MMBOE</th>
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<tr>
<td><strong>Atlantic Region</strong></td>
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<td>White Rose</td>
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<td></td>
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<td>S. Avalon Oil</td>
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<td>West White Rose Extensions</td>
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<td>North Amethyst</td>
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<td>4.4</td>
<td>65.4</td>
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<td>Terra Nova</td>
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<td>13.8</td>
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<td>South White Rose</td>
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<td>N. Amethyst Hibernia Well</td>
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<td>9.9</td>
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<td>North White Rose</td>
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<td>White Rose Gas</td>
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<td>-</td>
<td>3.5</td>
<td>-</td>
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<td>Flemish Pass Oil</td>
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<td>Bay du Nord</td>
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<td>Harpoon</td>
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<td>Mizzen</td>
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<td>Oil: Wenchang</td>
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<td>Liuhua 34-2</td>
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<td>Madura BD</td>
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<td>29.0</td>
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<td>5 Indonesia discoveries (MDK+MAC)</td>
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<td>Indonesia Next Phases</td>
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<td><strong>Oil Sands</strong></td>
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<td>Sunrise Phase 1 and 2</td>
<td>219.8</td>
<td>1,202.5</td>
<td>431.7</td>
<td>644.3 (Thermal)</td>
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<td>McMullen Cold/TCP/Thermal</td>
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<td>Sunrise Energy Project Phase 3</td>
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<td>Saleski</td>
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<td>10 other Oil Sands properties</td>
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Appendix: Liwan Economics

- Operating costs ~10%
- Taxes and royalties ~20%
- Exploration cost recovery ~$800mm

<table>
<thead>
<tr>
<th>Field</th>
<th>Gross Production Capacity</th>
<th>Price</th>
<th>Time Frame</th>
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<tbody>
<tr>
<td>Liwan 3-1 Gas NGLs</td>
<td>300 mmcf/d 10-14 mboe/d</td>
<td>~$11-13/mcf ~$100/boe</td>
<td>Current Current</td>
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<td>Liuhua 34-2 Gas</td>
<td>40 mmcf/d</td>
<td>~$11-13/mcf</td>
<td>H2 2014</td>
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<tr>
<td>Liuhua 29-1 Gas</td>
<td>1-200 mmcf/d</td>
<td>In Negotiation</td>
<td>2017</td>
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</tbody>
</table>
Gas Resource Play Templates

1. Ansell – Cardium Horizontal Wells
2. Ansell – Wilrich Horizontal Wells
3. Ansell – Falher Notikewin Wells
4. Strachan – Cardium
5. Kakwa – Wilrich
6. Kaybob – Duvernay
7. Kakwa – Montney
8. Sinclair – Montney
9. Horn River – Muskwa / Evie
10. Wild River – Duvernay
1. Ansell – Cardium

- Total Liquids Content: ~60 bbls/MMcf
- Estimated Ultimate Recovery/Well: ~600 MBOE
- Well Cost (current to steady): ~$9.5 MM to $7.5 MM

**Background Facts**
- ~120,000 net acres Cardium rights*
- ~300 gross vertical wells and 16 Hz drilled to date
- 11 HZ wells on production to date: all ball drop system
- ~350 net locations
- Vertical depth: 2,400 m
- Lateral Length: 1,500 m
- Technology: RSS/Conventional directional drilling
- Time to drill: 28 days

**Drilling Summary**
- Number of stages: 12 - 18
- Length: 1500 m HZ section
- Type of frac: ball drop
- Tonnes per stage: 25T – 50T
- Type of fluid / Amount of fluid: Propane/water
- Typical fracs for the area: Slick water, Propane

**Completions Summary**
- Total Liquids Content: ~60 bbls/MMcf
- Estimated Ultimate Recovery/Well: ~600 MBOE
- Well Cost (current to steady): ~$9.5 MM to $7.5 MM

**Notes**: Wilrich & other Spirit River rights sometimes also held

*Wilrich & other Spirit River rights sometimes also held

![Ansell Cardium Horizontals](image)
2. Ansell – Wilrich

- Total Liquids Content: ~21 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~833 MBOE
- Well Cost (current to steady): ~$9.0 MM to $6.2 MM

**Background Facts:**
- ~100,000 net acres Wilrich rights*
- 10 Hz producers as of Apr. 2014
- ~340 net locations

**Cardium & other Spirit River rights sometimes also held

**Drilling Summary**
- Vertical Depth: 3,100 m
- Lateral Length: 1,500 m
- Technology: RSS / Conventional Directional Drilling
- Time to Drill: 33 days

**Completions Summary**
- Number of Stages: 10-12
- Length: 1,500 m HZ Section
- Type of Frac: Ball Drop
- Tonnes per Stage: 80T
- Type of Fluid / Amount of Fluid: Slickwater
- Typical Fracs for the Area: Slickwater
3. Ansell – Falher/Notikewin Horizontal Wells

- Total Liquids Content: ~42 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~778 MBOE
- Well Cost (current): ~$9.0 MM

### Background Facts
- ~100,000 net acres
- 6 Hz producers as of Apr. 2014
- ~90 net locations

**Cardium & other Spirit River rights sometimes also held

### Drilling Summary
- Vertical Depth: 2900 m
- Lateral Length: 1500 m
- Technology: RSS / Conventional Directional Drilling
- Time to Drill: 33 days

### Completions Summary
- Number of Stages: 9 - 19
- Length: 1200-2300 m HZ Section
- Type of Frac: Ball Drop
- Tonnes per Stage: 80T
- Type of Fluid: Slickwater
- Typical Fracs for the Area: Slickwater

![Cumulative Raw Gas Production vs. Months on Production](https://example.com/production_chart.png)
### 4. Strachan – Cardium Horizontal Wells

- Total Liquids Content: ~62 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~507 MBOE
- Well Cost (current to steady): ~$5.1 MM to $4.3 MM

#### Background Facts
- ~11,000 net acres
- 2 Hz producers as of March 2014
- ~25 net locations

#### Drilling Summary
- Vertical Depth: 3,100 m
- Lateral Length: 1,100 m
- Technology: Monobore Directional Drilling
- Time to Drill: 24 days

#### Completions Summary
- Number of Stages: 15
- Length: 1,100 m HZ Section
- Type of Frac: Ball Drop
- Tonnes per Stage: 20T
- Type of Fluid / Amount of Fluid: Nitrified Gel
- Typical Fracs for the Area: Slickwater / Oil
5. Kakwa – Wilrich

- Total Liquids Content: ~27 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~1,132 MBOE
- Well Cost (current): ~$9.5 MM
6. Kaybob – Duvernay

- Total Liquids Content: ~200 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~765 MBOE
- Well Cost (current to steady): ~$14.7 MM to $13.2 MM

### Background Facts
- ~20,000 net acres
- 10 producers
- 10 wells drilled to date
- ~60 net locations

### Drilling Summary
- Vertical depth: 3,100 m
- Lateral Length: 1,800 m
- Technology: Managed Pressure Drilling
- Time to drill: 45 days

### Completions Summary
- Number of stages: 18-20
- Length (HZ section): 1,800 – 2,000m
- Type of frac: plug-n-perf & ball-drop
- Tonnes per stage: 100 to 150
- Type of fluid/Amount of fluid: slickwater/20,000m³
- Typical fracs for the area: perf-n-plug or ball drop with slickwater

- Total Liquids Content: ~100 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~626 MBOE
- Well Cost (current to steady): ~$11.7 MM to $7.8 MM

### Background Facts
- ~14,000 net acres
- 1 well drilled to date
- ~30 net locations

### Drilling Summary
- Vertical depth: ~3400m
- Lateral Length: ~1300m
- Invert mud overbalanced
- Time to drill: est. 60 drilling days & 70 total

### Completions Summary
- 17 stages
- Plug and Perf or Open Hole Ball Drop
- Proppant: ~60 tonnes per stage
- Fluid: Slick Water or Gelled Hydrocarbon w/ N2
- Similar completion to other Montney wells in area

---

#### Table:

<table>
<thead>
<tr>
<th>Background Facts</th>
<th>Drilling Summary</th>
<th>Completions Summary</th>
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<tbody>
<tr>
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<td>Vertical depth: ~3400m</td>
<td>17 stages</td>
</tr>
<tr>
<td>1 well drilled to date</td>
<td>Lateral Length: ~1300m</td>
<td>Plug and Perf or Open Hole Ball Drop</td>
</tr>
<tr>
<td>~30 net locations</td>
<td>Invert mud overbalanced</td>
<td>Proppant: ~60 tonnes per stage</td>
</tr>
<tr>
<td></td>
<td>Time to drill: est. 60 drilling days &amp; 70 total</td>
<td>Fluid: Slick Water or Gelled Hydrocarbon w/ N2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Similar completion to other Montney wells in area</td>
</tr>
</tbody>
</table>

---

**Kakwa Montney Cumulative Production vs. Husky Type Curve**

- **Husky**
- **Industry**
- **Type Curve**

Updated Jan 27th, 2014
8. Sinclair – Montney (Liquids Rich)

- Total Liquids Content: ~56 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~721 MBOE
- Well Cost (current to steady): ~$11.4 MM to $8 MM
9. Horn River – Muskwa

- Total Liquids Content: ~0 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~1,500 MBOE
- Well Cost (current to steady): No drilling activity

### Background Facts
- ~30,000 net acres for both zones
- 3 (1 Hz, 2 Verts) wells drilled to date
- ~150 net locations (~100 Muskwa, ~50 Evie)

### Drilling Summary
- Vertical depth: ~2200m
- Lateral Length: ~2400m
- Invert mud overbalanced
- Time to drill: est. 45 days

### Completions Summary
- 24 stages
- Plug and Perf
- Proppant: ~200 tonnes per stage
- Fluid: Slick Water
- Similar completion to other Muskwa wells in area
10. Wild River – Duvernay

- Total Liquids Content: ~5 bbls/mmcf
- Estimated Ultimate Recovery/Well: ~1,636 MBOE
- Well Cost (current to steady): No Hz drilling activity

<table>
<thead>
<tr>
<th>Background Facts</th>
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<th>Completions Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>• ~34,000 net acres</td>
<td>• Vertical depth: 3,940 m</td>
<td>• Number of stages: 18-20</td>
</tr>
<tr>
<td>• 0 net producers</td>
<td>• Lateral Length: 1,400 m</td>
<td>• Length (HZ section): 1,600 – 1,800 m</td>
</tr>
<tr>
<td>• 2 vertical wells drilled but not completed</td>
<td>• Technology: Managed Pressure Drilling</td>
<td>• Type of frac: plug-n-perf</td>
</tr>
<tr>
<td>• ~125 net locations</td>
<td>• Time to drill: 60 days</td>
<td>• Tonnes per stage: 100</td>
</tr>
<tr>
<td>• No analog HZ producer</td>
<td></td>
<td>• Type of fluid/Amount of fluid: slickwater/18,000m³</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Typical fracs for the area: perf-n-plug or ball drop with slickwater</td>
</tr>
</tbody>
</table>
Oil Resource Play Templates

1. Wapiti – Cardium
2. Oungre – Bakken
3. Saskatchewan – Bakken
4. Redwater – Viking
5. Alliance / Sumner – Viking
6. Elrose – Viking
7. Coleville / Hoosier – Viking
8. Doddsland – Viking
9. Rainbow – Muskwa
10. NWT – Canol
1. Wapiti – Cardium

- Estimated Ultimate Recovery/Well: ~380 MBOE
- Well Cost (current): $5.5 MM

<table>
<thead>
<tr>
<th>Background Fact</th>
<th>Drilling Summary</th>
<th>Completions Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>~12,000 net developable acres</td>
<td>Vertical depth: 1,300m</td>
<td>Number of stages: 15 - 17</td>
</tr>
<tr>
<td>24 producing project wells</td>
<td>Lateral Length: 1,100m – 1,300m</td>
<td>Length: 100m</td>
</tr>
<tr>
<td>27 wells drilled to date</td>
<td>Technology: Monobore</td>
<td>Type of frac: Open hole ball drop</td>
</tr>
<tr>
<td>~55 net locations</td>
<td>Time to drill: 17 days</td>
<td>Tonnes per stage: 25T</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Type of fluid / Amount of fluid: Slick Oil, 100m³/stage</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Typical fracs for the area: Gelled oil, Slick water, Gas</td>
</tr>
</tbody>
</table>
2. Oungre – Bakken / Torquay

- Estimated Ultimate Recovery/Well: ~125 - 145 MBOE
- Well Cost (current): $2.2 MM

<table>
<thead>
<tr>
<th>Background Facts</th>
<th>Drilling Summary</th>
<th>Completions Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>~22,000 net acres (27.25 net sections)</td>
<td>Vertical depth: 2,300 m</td>
<td>Type of frac: cemented liner</td>
</tr>
<tr>
<td>53 Hz producers: 43 Bakken, 10 Torquay</td>
<td>Lateral length: 1,400 m</td>
<td>Number of stages: 25</td>
</tr>
<tr>
<td>55 wells drilled to date: 2 Torquay w/o completions</td>
<td>Technology: Casing to ICP (177.8mm)</td>
<td>Tonnes per stage: 20</td>
</tr>
<tr>
<td>~110 net locations</td>
<td>Time to drill: 15 days</td>
<td>Type of fluid/Amount: x-link gel/3,500 m³</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Typical fracs for the area: 11-20 T</td>
</tr>
</tbody>
</table>
3. S.W. Saskatchewan – Multi-Zone

- New position – no wells drilled to date
- Estimated Well Cost: $4 MM

<table>
<thead>
<tr>
<th>Background Facts</th>
<th>Drilling Summary</th>
<th>Completions Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>~140,000 net acres</td>
<td>Vertical depth: 2,100 m</td>
<td>Type of frac: TBD</td>
</tr>
<tr>
<td>No producers</td>
<td>Lateral length: 1,600 m</td>
<td>Number of stages: TBD</td>
</tr>
<tr>
<td>No net wells drilled to date</td>
<td>Technology: TBD</td>
<td>Tonnes per stage: TBD</td>
</tr>
<tr>
<td></td>
<td>Time to drill: TBD</td>
<td>Type of fluid/Amount: TBD</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Typical fracs for the area: 11-20 T (Oungre)</td>
</tr>
</tbody>
</table>
4. Redwater – Viking

- Potential Estimated Ultimate Recovery/Well: 60 MBBLS
- Estimated Well Cost (current): $1.8 MM

<table>
<thead>
<tr>
<th>Background Facts</th>
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<th>Completions Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>~18,000 net acres</td>
<td>Vertical depth: 650 to 700m</td>
<td>Number of stages: 7-8</td>
</tr>
<tr>
<td>74 net wells drilled to date,</td>
<td>Lateral Length 600 to 700m</td>
<td>Length: 600 to 700m</td>
</tr>
<tr>
<td>~90 net locations</td>
<td>Technology – monobore</td>
<td>Type of frac: multiple</td>
</tr>
<tr>
<td></td>
<td>Time to drill – 4 days with monobore</td>
<td>Tonnes per stage: 10 to 15</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Type of fluid / Amount of fluid: cross linked gel water/ 500 to 650m3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Typical fracs for the area: same as industry</td>
</tr>
</tbody>
</table>
5. Alliance/Sumner – Viking

- Potential Estimated Ultimate Recovery/Well: 70-85 MBBLS
- Estimated Well Cost (current): $1-1.6 MM

### Background Facts
- ~80,000 net acres
- 27 producing project wells
- 30 wells drilled to date (24 Alliance, 6 Sumner)
- ~280 net locations

### Drilling Summary
- Vertical depth: 835 mKB (Alliance), 900 mKB (Sumner)
- Lateral Length: 600m
- Technology: 4 ½” Monobore (Alliance), Intermediate casing with slotted liner (Sumner)
- Time to drill: 5.0 days

### Completions Summary
- Number of stages: 10
- Type of frac: Cemented liner, Trican/NCS Port
- Tonnes per stage: 15 T
- Type of fluid / Amount of fluid: Crosslinked gelled water / 720 m³
- Typical fracs for the area: Crosslinked gelled water, 15T/stg

---

![Husky Alliance Viking Cumulative Production](image-url)
6. Elrose – Viking

- Potential Estimated Ultimate Recovery/Well: 50 MBBLS
- Estimated Well Cost (current): $1.4 MM

<table>
<thead>
<tr>
<th>Background Facts</th>
<th>Drilling Summary</th>
<th>Completions Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>- ~27,000 net acres</td>
<td>- Vertical depth: 725 mKB</td>
<td>- Number of stages: 10</td>
</tr>
<tr>
<td>- 59 producing project wells</td>
<td>- Lateral Length: 600 m</td>
<td>- Type of frac: Cemented liner, Trican/ NCS Burst port</td>
</tr>
<tr>
<td>- 59 wells drilled to date</td>
<td>- Technology: 4 ½” Monobore</td>
<td>- Tonnes per stage: 15 T</td>
</tr>
<tr>
<td>- ~80 net locations</td>
<td>- Time to drill: Avg 4.7 days (Best – 3.9 days)</td>
<td>- Type of fluid / Amount of fluid: Crosslinked gelled water / 630 m3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Typical fracs for the area: 10stg, 15T Gelled water</td>
</tr>
</tbody>
</table>
7. Coleville/Hoosier – Viking

- Potential Estimated Ultimate Recovery/Well: 50 - 70 MBBLS
- Estimated Well Cost (current): $1.5 MM

### Background Facts
- ~16,000 net acres
- 25 producing project wells
- 26 gross wells drilled to date
- ~80 net locations

### Drilling Summary
- Vertical depth: 710 mKB
- Lateral Length: 600 m
- Technology: 4 ½” Monobore
- Time to drill: Avg 3.3 days

### Completions Summary
- Number of stages: 11
- Type of frac: Cemented liner, Trican Burst port
- Tonnes per stage: 15 T
- Type of fluid / Amount of fluid: Crosslinked gelled water / 850 m³
- Typical fracs for the area: 15T Energized N₂
8. Dodsland – Viking

- Potential Estimated Ultimate Recovery/Well: 55 MBBLS
- Estimated Well Cost (current): $1.5 MM

### Background Facts
- ~40,000 net acres
- 4 producing project wells
- 6 wells drilled to date
- ~45 net locations

### Drilling Summary
- Vertical depth: 625 mKB
- Lateral Length: 600 m
- Technology: 4 ½” Monobore
- Time to drill: Avg 3.8 days

### Completions Summary
- Number of stages: 10
- Type of frac: Cemented liner, Trican Burst port
- Tonnes per stage: 15 T
- Type of fluid / Amount of fluid: Nitrified gelled water / 275 m³
- Typical fracs for the area: Perf and selective frac tool
9. Rainbow – Muskwa

- Still de-risking

<table>
<thead>
<tr>
<th></th>
<th>Q1 2014 Production (boe/d)</th>
<th>Potential EUR/Well (mboe)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil Resource</strong></td>
<td>90</td>
<td>~140</td>
</tr>
<tr>
<td><strong>Gas Resource</strong></td>
<td>94</td>
<td>~820</td>
</tr>
</tbody>
</table>

### Background Facts

| **Oil Resource**     | ~400,000 net acres  |
|                      | 5 producing project wells |
|                      | 3 pilot wells and 20 Hz drilled to date |
|                      | 8 wells completed to date |

| **Gas Resource**     | 70,000 net acres  |
|                      | 1 Hz producer  |
|                      | 6 liquids rich wells drilled to date (3 Hz’s, 2 Vert & 1 Susp Hz) |

### Drilling Summary

| **Oil Resource**     | Vertical depth: 1700m TVD  |
|                      | Lateral Length: Current: 1800m, Future: 1300m |
|                      | Time to drill: Current: 17 days, Future: 12 days |

| **Gas Resource**     | Vertical depth: ~1800m  |
|                      | Lateral Length: ~1600 to 2000m |
|                      | Time to drill: est. 21 drilling days & 25 total |

### Completions Summary

| **Oil Resource**     | Number of stages: Current: 18, Future: 20 |
|                      | Typical fracs for the area: Evaluating |
|                      | **Gas Resource**     | 18 to 22 stages  |
|                      | Similar completion to other Muskwa wells in area |
10. Slater River – Canol (Oil/ Liquids rich gas)

- Evaluating

<table>
<thead>
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</thead>
</table>
| • ~300,000 net acres
  • 2 vertical strat wells with completions
  • Initial development model includes oil phase | • Vertical depth: 1000-1700m TVD
  • Lateral Length: ~1200m | • Number of stages: TBD
  • Stage Length TBD
  • Tonnes per stage: TBD |