Transforming an oil sands leader
A strategic and transformative transaction

50% Working Interest in FCCL

Emerging Oil Sands

Conventional Oil & Gas

Refining & Marketing

Reinforces position as an oil sands leader while adding a second growth platform

50% Working Interest in FCCL
- 178,000 bbls/d of oil sands production (net)
- 368,000 bbls/d of regulatory approved capacity (net)
- 3.24 billion barrels of 2P reserves (net)

Established Deep Basin Presence
- ~3.0 million net acres across the Deep Basin
- 120,000 BOE/d of production (26% liquids)
- 725 MMBOE of 2P reserves (27% liquids)
- 1.4 BCF/d of net natural gas processing capacity

Acquired from ConocoPhillips for $17.7 billion

Note: All figures are represented on a net basis assuming a January 1, 2017 effective date. Regulatory approved capacity includes existing production. Assumes an exchange rate of $1.33.
Transforming an oil sands leader

• **Immediately accretive to per share metrics**
  • expected to increase 2018F adjusted funds flow per share by 18%, net of planned asset sales
  • expected to reduce 2018F operating costs per BOE by 16% and G&A per BOE by 26%, net of planned asset sales

• **Enhances scale and capital flexibility**
  • pro forma production base of 588 MBOE/d
  • pro forma 2P reserves of 7,763 MMBOE

• **Maintains financial resilience**
  • leverages Cenovus’s existing cash balance into premier assets while preserving financial strength
  • scale and capital structure support access to capital markets and investment grade credit ratings from S&P Global Ratings, Fitch Ratings, and DBRS Limited
  • plan to revisit the optimal level of dividend after substantial completion of asset sales

Note: Production volumes for peers based on consensus estimates as per FactSet as of March 17, 2017. Enterprise values per Bloomberg as of March 17, 2017; pro forma calculated as current enterprise value plus total transaction value before the impact of planned asset sales. Cenovus 2017F production volumes represent the midpoint of December 8, 2016 guidance. Pro forma 2017F production volumes assume a full year contribution from the acquired assets. In each case after announced, but not yet completed transactions and before proposed asset sales for peers. Peers include ARX, CNQ, CPG, ECA, HSE, IMO, PEY, SU, TOU, and VII.
Anchor position in two high quality plays

- **Consolidates ownership of top-tier oil sands projects**
  - no incremental staff or integration required
  - low-risk growth profile with emerging technology upside

- **Deep Basin assets high-grade portfolio**
  - high quality position in the prolific Deep Basin of Alberta and British Columbia
  - ~3.0 million net acres with significant owned and majority operated infrastructure
  - deep inventory of short-cycle and high IRR potential drilling opportunities
  - provides significant capital flexibility

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Consolidates ownership of top-tier oil sands projects

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Deep Basin assets high-grade portfolio

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- provides significant capital flexibility
## Detailed transaction overview

### Asset overview
- 298,000 BOE/d (70% liquids) based on 2017F estimates
  - ConocoPhillips’ 50% interest in the FCCL Partnership (178,000 bbls/d 2017F)
  - Majority of ConocoPhillips’ Deep Basin assets (120,000 BOE/d 2017F; 26% liquids; 17% decline rate)
- 2017F Operating Margin of $1.8 billion based on US$50/bbl WTI
- ~3.0 million net acres of land across the Deep Basin (70% average working interest)
- 3,966 MMBOE of 2P reserves as of December 31, 2016
- Approximately 1.4 BCF/d of net natural gas processing capacity

### Consideration
- Total consideration of $17.7 billion
  - $14.1 billion in cash
  - 208 million Cenovus common shares to vendor

### Contingent payment terms
- Contingent payments based on $52/bbl Western Canadian Select trigger price
- Five-year term beginning on the closing date of the transaction
- Based on current FCCL volumes Cenovus retains 80-85% of the benefit above the trigger price

### Financing
- $3.6 billion of existing cash and committed credit facility
- $3.0 billion concurrent bought-deal common share equity offering
- Remainder of cash purchase price financed through long-term debt and asset sale proceeds
- $10.5 billion of fully committed bridge facilities in place to manage timing differences

### Other information
- Transaction subject to customary regulatory approvals

### Timing
- January 1, 2017 effective date; closing expected in Q2 2017

Note: Production and reserves data are on a net basis assuming a January 1, 2017 effective date. See Advisory.
A compelling three-year outlook

Highly accretive to key financial and operational metrics

<table>
<thead>
<tr>
<th>FORECAST FINANCIAL MEASURES</th>
<th>Cenovus</th>
<th>Cenovus pro forma impact (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted funds flow $/sh</td>
<td>$1.90</td>
<td>$2.45</td>
</tr>
<tr>
<td>Operating costs $/BOE</td>
<td>$10.15</td>
<td>$9.45</td>
</tr>
<tr>
<td>General &amp; administrative costs $/BOE</td>
<td>$2.45</td>
<td>$1.85</td>
</tr>
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</table>

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<tr>
<th>FORECAST PRODUCTION &amp; PRO FORMA RESERVES as of December 31, 2016</th>
<th>Cenovus</th>
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</thead>
<tbody>
<tr>
<td>2017F</td>
<td>2017F (before asset sales)</td>
<td>2018F (post asset sales)</td>
</tr>
<tr>
<td>Forecast total production MBOE/d</td>
<td>290</td>
<td>588</td>
</tr>
<tr>
<td>Production per share BOE/d/MM sh</td>
<td>348</td>
<td>478</td>
</tr>
<tr>
<td>2P reserves MMBOE</td>
<td>3,797</td>
<td>7,763</td>
</tr>
<tr>
<td>2P reserves per share BOE/sh</td>
<td>4.55</td>
<td>6.30</td>
</tr>
</tbody>
</table>

Note: Cenovus 2017F represents the midpoint of December 8, 2016 guidance. Pro forma impact is for illustrative purposes and assumes successful completion of Acquisition and planned asset sales effective January 1, 2018. Per share figures assume vendor take-back equity and successful completion of concurrent bought-deal common share equity offering before exercise of over-allotment option.
Transaction is fully funded

Financing strategy supports execution of transaction

- Successfully executed strategic financing plan
  - issued $3.6 billion of Cenovus common shares to ConocoPhillips
  - closed $3.0 billion common equity bought deal to fund a portion of purchase price
  - priced US$2.9 billion Senior Notes offering
  - utilizing a portion of cash on hand and available revolving credit facility
- Pelican Lake and Suffield disposition programs underway
  - further asset sales to be initiated in 2017

Note: Assumes an exchange rate of $1.33.
Maturity and liquidity profile

Strong liquidity pro forma the acquisition

- Committed to investment grade credit ratings
  
  - investment grade ratings from S&P Global Ratings, Fitch Ratings, and DBRS Limited
  
- Intend to repay borrowings under the Asset Sale Bridge Facility through the sale of certain of our assets

- Expect to have approximately $4.0 billion of available liquidity pro forma the acquisition
  
  - combination of cash and availability on the existing credit facility
  
  - sufficient liquidity to fund working capital needs and operations for the foreseeable future

- US $7.65 billion outstanding with weighted-average cost of debt of ~5.2%

Debt maturity profile

Note: US$ principal amounts
Committed to executing on asset sales

Depth of portfolio provides optionality for asset sales

- High degree of confidence in ability to execute dispositions and repay outstanding bridge loan
  - Pelican Lake and Suffield in market
  - represents ~45,000 BOE/d based on 2017F (61% liquids)
- Depth of portfolio provides strategic optionality
  - other legacy conventional oil & gas properties
  - royalty interests
  - infrastructure assets
- $3.6 billion asset sale bridge consists of three tranches payable over 12, 18, and 24 months

Potential asset sale proceeds

Potential proceeds $ billions

Average daily production (MBOE/d)

Note: Potential sale proceeds per flowing barrel of oil equivalent based on publicly announced precedent transactions in the WCSB.
Preserving financial resilience

Financing plan supports investment grade ratings

- Targeting 1.0 - 2.0x debt to adjusted EBITDA and 30 – 40% debt to capitalization over the long-term
- Financial covenants remain unchanged
  - ≤65% debt to capitalization
- Optimizing portfolio through asset sales
  - Pelican Lake and Suffield in market
  - further asset sales to be initiated in 2017

<table>
<thead>
<tr>
<th></th>
<th>S&amp;P</th>
<th>Moody’s</th>
<th>DBRS</th>
<th>Fitch</th>
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<td><strong>Pre-announcement</strong></td>
<td></td>
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<tr>
<td>BBB</td>
<td>Ba2</td>
<td>BBB (high)</td>
<td>Not Rated</td>
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<tr>
<td>Stable outlook</td>
<td>Stable outlook</td>
<td>Stable outlook</td>
<td></td>
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<tr>
<td><strong>Post-acquisition</strong></td>
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<tr>
<td>BBB</td>
<td>Ba2</td>
<td>BBB (high)</td>
<td>BBB-</td>
<td></td>
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<tr>
<td>Negative outlook</td>
<td>Stable outlook</td>
<td>Under review - negative implications</td>
<td>Stable outlook</td>
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</tbody>
</table>

Debt metrics expected to trend lower

Note: Assumes successful completion of acquisition, as well as potential asset sales as of January 1, 2018. US$50/bbl WTI case assumes constant US$50/bbl WTI and US$3/mcf NYMEX. Strip pricing as at December 31, 2016. See Advisory.
Consolidating our interest in top-tier oil sands

Overview of FCCL Partnership assets

- Acquiring remaining 50% interest in two top-tier producing thermal oil sands projects with current production capacity of 390,000 bbls/d
  - lowest portfolio-weighted steam-oil ratios
  - low operating and sustaining capital costs
- Combined regulatory approved capacity of 735,000 bbls/d at Christina Lake, Foster Creek, and Narrows Lake
- Full exposure to future upside potential through emerging technologies (e.g. drilling improvements, flow control devices, facility modifications, implementation of a solvent aided process, and partial upgrading)

FCCL Partnership summary statistics

- 2017F production: 356,000 bbls/d (100% oil)
- Total net acres: 0.3 million
- Regulatory approved capacity: 735,000 bbls/d
- 2P reserves: 6,480 MMbbls (72% proved)

Foster Creek
- 2017F production: 158,000 bbls/d
  - Production capacity: 180,000 bbls/d
  - December 2016 SOR: 2.4x
  - 2P reserves: 2,660 MMbbls

Christina Lake & Narrows Lake
- 2017F production: 198,000 bbls/d
  - Production capacity: 210,000 bbls/d
  - December 2016 SOR: 1.9x
  - 2P reserves: 3,820 MMbbls

Note: Production and reserves data are on a gross basis assuming a January 1, 2017 effective date and assuming closing of the proposed Acquisition. Figures relate to FCCL Partnership assets only. Production capacity includes currently producing projects at Foster Creek and Christina Lake. Regulatory approved capacity includes existing production.
Largest & most efficient thermal portfolio

Reinforcing our position as a leader in SAGD

<table>
<thead>
<tr>
<th>Production (Mbbls/d)</th>
<th>December 2016 Average Production</th>
<th>Portfolio-Weighted SOR</th>
<th>Portfolio-Weighted SOR</th>
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<tr>
<td>Pro forma</td>
<td>2.1</td>
<td>4.0</td>
<td>4.3</td>
</tr>
<tr>
<td>Cenovus</td>
<td>2.1</td>
<td>2.2</td>
<td>2.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3.1</td>
<td>3.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2.5</td>
<td>2.5</td>
</tr>
</tbody>
</table>

Note: Production data and steam-oil ratio based on AER data as of December 2016. Portfolio-weighted SOR calculated based on project operator and is a measure of current project efficiency. Peers include ATH, CNOOC, CNQ, COP, DVN, HSE, IMO, MEG, PGF, and SU.
**A demonstrated track record of execution**

**Cenovus is the largest thermal oil sands producer**

- Successfully executed 14 major capacity expansions representing 390,000 bbls/d (gross) of production capacity
  - 26% cumulative annual growth rate since 2006
- Industry leading capital efficiencies
  - Resuming construction of Christina Lake phase G with go-forward capital efficiency at $16,000 - $18,000 per flowing barrel of expected production capacity (50,000 bbls/d)
- Expected to provide details on current and future growth projects at June 2017 Investor Day
  - Foster Creek phase H (30,000 bbls/d gross) and Narrows Lake phase A (45,000 bbls/d gross) undergoing rigorous cost review

**A track record of successful execution**

Produced capacity (Mbbls/d)

- 26% CAGR in production capacity since 2006

*Note: Production capacity is shown on a gross basis.*
Technology innovation enhances value

Focused innovation drives technological advancement

- Targeting oil sands sustaining capital costs of $7/bbl
- Each $1/bbl reduction in finding and development costs has the potential to represent an estimated $0.65 billion (gross) in NPV over the remaining life of our producing projects
- Plans to leverage innovation to unlock significant value:
  - well pad design and longer reach horizontal wells
  - flow control devices
  - new start-up techniques
  - implementation of a solvent-aided process
  - partial upgrading technology initiatives
  - facility process enhancements

Emerging technology drives incremental oil sands value

Note: Figures are calculated on a gross basis and represent the expected increase in net present value over the remaining life cycle of current and potential oil sands projects. See Advisory.
Deep Basin provides second growth platform

Overview of Deep Basin

- One of the largest Deep Basin land positions in the WCSB
- Three core operating areas: Elmworth-Wapiti, Kaybob-Edson, and Clearwater
- Low decline production base coupled with significant liquids-rich development upside
- Deep inventory of short-cycle, high IRR potential drilling opportunities in areas that attract capital from offsetting operators
- Assets have been capital constrained in recent years
- 1.4 BCF/d of majority owned and operated net natural gas processing capacity

Deep Basin summary statistics

- 2017F production: 120,000 BOE/d (26% liquids; 17% decline rate)
- Total net acres: ~3.0 million
- Proved + probable + future drilling opportunities: ~ 1,500
- 2P reserves: 725 MMBOE (62% proved)
Over a decade of future drilling opportunities

~1,500 potential drilling opportunities identified

- Initial development focused on the Spirit River and Montney formations
- Plan to retain high quality technical staff associated with the acquired assets
- Attractive half-cycle development economics supported by majority owned and operated infrastructure
  - type well information provided by independent qualified reserve evaluator

Focused on the Spirit River and Montney formations

- Internal Cenovus estimates
- GLJ - Probable
- GLJ - Proved

Future drilling opportunities by targeted formation

Large inventory of short-cycle, high IRR potential drilling opportunities

<table>
<thead>
<tr>
<th>GLJ type curve information</th>
<th>IP365 (boe/d)</th>
<th>Well costs ($MM,DC&amp;T)</th>
<th>Gas (%)</th>
<th>IRR (%)</th>
<th>NPV 10% before-tax ($MM)</th>
<th>Payout (years)</th>
<th>F&amp;D ($/boe)</th>
<th>Recycle ratio (x)</th>
<th>1 year capital efficiency ($k/flowing)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elmworth-Wapiti Montney type well</td>
<td>478</td>
<td>$6.2</td>
<td>58%</td>
<td>&gt;100%</td>
<td>$8.7</td>
<td>~1.6</td>
<td>$4.90</td>
<td>4.1</td>
<td>$13.0</td>
</tr>
<tr>
<td>Kaybob Spirit River type well</td>
<td>582</td>
<td>$6.4</td>
<td>80%</td>
<td>~84%</td>
<td>$5.8</td>
<td>~1.8</td>
<td>$5.60</td>
<td>2.8</td>
<td>$11.0</td>
</tr>
<tr>
<td>Clearwater Spirit River type well</td>
<td>395</td>
<td>$4.2</td>
<td>81%</td>
<td>~87%</td>
<td>$3.9</td>
<td>~1.8</td>
<td>$5.50</td>
<td>2.8</td>
<td>$10.7</td>
</tr>
</tbody>
</table>

Note: See Advisory for key underlying assumptions and risks and a description of the metrics provided above. Assumes constant US$50/bbl WTI and NYMEX US$3.00/mcf.
Maximizing value in the Deep Basin

Taking a disciplined approach to development

- Expect to run a three rig program in 2017 and ramping up thereafter
  
  - potential to grow production from 120,000 BOE/d in 2017F to approximately 170,000 BOE/d in 2019F
  
  - acquired asset base expected to be internally funded

- Capital will be flexible and can be increased or decreased depending on commodity price environment
  
  - ability to leverage 1.4 BCF/d of net processing capacity within the acquired asset portfolio to drive growth
  
  - three year infrastructure budget of $250-$300 million to maximize throughput and optimize development

Internally funded growth potential

Deep Basin capital expenditures and operating margin ($ millions)

- Capital Expenditures
- Operating Margin

Deep Basin net wells drilled and production (Net wells; MBOE/d)

- Net Wells
- Production

Note: Production growth assumes favorable drilling results and actual number of wells drilled within estimates provided. See Advisory for other key underlying assumptions and risks.
The new Cenovus

Overview

- One of the largest Canadian energy companies
- A leader in SAGD development and innovation
- Substantial inventory of regulatory approved oil sands projects
- Low decline production base coupled with significant development upside
- Deep inventory of highly economic drilling opportunities in areas that attract capital from offsetting operators
- Deep Basin assets provide a second platform for scalable production growth

Summary statistics

- 2017F production: 588,000 BOE/d (75% liquids, before asset sales)
- Total net acres: ~8.6 million
- 2P reserves: 7,763 MMBOE (70% proved)

Note: Production and reserves data are on a gross basis assuming a January 1, 2017 effective date and assuming closing of the proposed Acquisition.
Significant cash generation capacity

**Capital allocation priorities**

- Financial resilience and safe, reliable operations
- Sustainable returns to shareholders
  - plan to revisit the optimal level of dividend after substantial completion of asset sales
- Value added growth at Christina Lake phase G and short-cycle, high IRR potential drilling opportunities
  - Christina Lake phase G capital efficiencies are industry leading
  - Deep Basin development
  - optimizing development plans for Foster Creek phase H and Narrows Lake phase A
- Portfolio optimization, advancing emerging projects, technology development, and margin enhancement
  - Pelican Lake and Suffield properties currently in market

**Free funds flow provides capital flexibility**

Note: Independent base case sensitivities assuming constant WTI, holding all other assumptions equal. Assumes NYMEX natural gas price of US$3.00/mcf. Includes the impact of planned asset sales. See Advisory.
A compelling three-year outlook

Increased scale and depth of portfolio

- Clear line of sight to production growth through steady capital investment
  - 125,000 bbls/d of potential near-term capacity at Christina Lake, Foster Creek, and Narrows Lake
  - over a decade of attractive drilling opportunities already identified on the acquired Deep Basin assets
- Asset sales high-grade the portfolio
  - Pelican Lake and Suffield in market
  - further asset sales to be identified in 2017
- Financial resilience supports future growth
  - targeting 1.0 - 2.0x debt to adjusted EBITDA and 30 – 40% debt to capitalization over the long-term

Second growth platform provides capital flexibility

Note: 2017F is before asset sales, 2018F and 2019F include the impact of planned asset sales as of January 1, 2018. See Advisory.

[Graphs showing Total Cenovus capital expenditures and Total Cenovus production over 2017F to 2019F]
Top-tier assets drive value-added growth

**Full exposure to future growth opportunities**

- Expanded portfolio enhances scale and generates significant long-term production growth
- Well defined oil sands growth opportunities with emerging technology upside
  - combined regulatory approved capacity of 735,000 bbls/d at Christina Lake, Foster Creek, and Narrows Lake
- Complimentary short-cycle, low-decline production provides second growth platform in the Deep Basin
  - ~1,500 potential drilling opportunities already identified

**Illustrative 5-year growth outlook**

Note: Pro forma production is for illustrative purposes and assumes successful completion of Acquisition. 2017F is before asset sales. 2018F - 2021F assume the impact of potential asset sales as of January 1, 2018. 2020F and 2021F assume Deep Basin capital expenditures held constant at 2019 forecast levels. See Advisory.
Low cost structure drives margin improvement

Cost reductions improving sustainability

- Oil sands netbacks remain competitive
  - estimated field level break-even oil price of US$25-$30/bbl WTI
- Structural cost reductions have improved our sustainability:
  - adjusted dividend and workforce with market conditions
  - ~50% reduction in sustaining capital
  - ~30% reduction in oil sands operating costs
  - ~30% reduction in G&A expenses
- Cenovus generated free funds flow in 2016 despite WTI averaging approximately US$43/bbl

Meaningful cost reductions drive future performance

Note: Field level break-even is defined as the price of US$ WTI required to offset royalties, transportation, and operating costs. Assumes US$/C$ foreign exchange rate of $0.70-$0.72, 32% light-heavy differential, sliding scale royalty payments, and condensate costs at 101% of Edmonton benchmark. 2017F based on December 8, 2016 guidance and is before the impact of the proposed Acquisition. See Advisory.
Downstream assets provide integration

**Downstream integration helps to mitigate differentials**

- Approximately 25% of total blended bitumen price exposure can be mitigated with heavy oil processing capacity
  - Wood River and Borger refineries capable of processing 273,000 bbls/d (gross) of heavy oil
    - Cenovus owns a 50% non-operated working interest
- Transportation options provide further mitigation from wider light/heavy differentials
- Cenovus has no near term takeaway capacity constraints
  - Bruderheim rail facility provides incremental optionality

**Sufficient near term takeaway capacity**

Note: Based on 2017F production assuming a January 1, 2017 effective date and assuming closing of the proposed Acquisition. See Advisory.
A strategic and transformative transaction

• Provides accretion on key metrics

• Enhances scale and capital flexibility

• Maintains financial resilience

• Consolidates top tier oil sands projects

• High-grades portfolio with Deep Basin assets
Appendix
Christina Lake asset overview

**Asset overview**
- One of the highest quality thermal oil sands projects in the industry
- High average production per well and industry leading steam-oil ratio
- Christina Lake phase G is the next phase of potential development with production design capacity of 50,000 bbls/d
- Christina Lake phase G expected to be on stream in H2 2019 at a cost of $16,000 - $18,000 per flowing barrel on a go-forward basis

**Key statistics**

<table>
<thead>
<tr>
<th>Units</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current production capacity</td>
<td>bbls/d</td>
</tr>
<tr>
<td>Regulatory approved capacity</td>
<td>bbls/d</td>
</tr>
<tr>
<td>Average working interest</td>
<td>%</td>
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<tr>
<td>December 2016 SOR</td>
<td>x</td>
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<tr>
<td>2017F production</td>
<td>bbls/d</td>
</tr>
<tr>
<td>2P reserves</td>
<td>MMbbls</td>
</tr>
<tr>
<td>% oil / liquids</td>
<td>%</td>
</tr>
<tr>
<td>2017F capex</td>
<td>$ millions</td>
</tr>
</tbody>
</table>

Note: Figures are on a gross basis assuming successful completion of the proposed Acquisition. 2017F production and capital expenditures assume a January 1, 2017 effective date.
Foster Creek asset overview

Asset overview

• The first commercial steam-assisted gravity drainage project in the industry
• High quality reservoir with a December 2016 steam-oil ratio of 2.4
• Foster Creek phase H is the next phase of potential development with production design capacity of 30,000 bbls/d

Key statistics

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</tbody>
</table>

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Narrows Lake asset overview

Asset overview

- Expected to be the first commercial steam-assisted gravity drainage project to utilize solvents in the industry
- Solvent aided process is expected to reduce SOR by ~30% while increasing recovery factor by ~15%
- Narrows Lake phase A is the first phase of potential development with production design capacity of 45,000 bbls/d (gross)

Key statistics

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<tr>
<td>Average working interest</td>
<td>%</td>
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<td>Targeted SOR</td>
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<tr>
<td>2017F production</td>
<td>bbls/d</td>
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<tr>
<td>2P reserves</td>
<td>MMbbls</td>
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<tr>
<td>% oil / liquids</td>
<td>%</td>
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<tr>
<td>2017F capex</td>
<td>$ millions</td>
</tr>
</tbody>
</table>

Note: Figures are on a gross basis assuming successful completion of the proposed Acquisition. 2017F production and capital expenditures assume a January 1, 2017 effective date.
Elmworth-Wapiti asset overview

Asset overview

- ~1.2 million net acres of land developed largely with vertical wells; acreage held by production with minimal expiries
- Prolific hydrocarbon stack producing oil & gas from multiple formations
- Strong horizontal liquids-rich development potential within the Montney and Spirit River group
- Significant area infrastructure underpins near-term growth potential

Key statistics

<table>
<thead>
<tr>
<th>Units</th>
<th>Statistic</th>
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<tbody>
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<td>Net acres</td>
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</tr>
<tr>
<td>Proved + probable + future drilling opportunities</td>
<td>~310</td>
</tr>
<tr>
<td>Average working interest</td>
<td>~71</td>
</tr>
<tr>
<td>Net operated processing capacity</td>
<td>~585</td>
</tr>
<tr>
<td>2017F production</td>
<td>46,000</td>
</tr>
<tr>
<td>% oil / liquids</td>
<td>27</td>
</tr>
<tr>
<td>2017F capex</td>
<td>55</td>
</tr>
</tbody>
</table>

Note: 2017F production and capital expenditures assume a January 1, 2017 effective date.
Kaybob-Edson asset overview

**Asset overview**

- Asset anchored by Spirit River development and production in Kakwa and Edson
- Meaningful Montney and Duvernay potential with continued delineation activity by offsetting operators
- Additional multi-horizon potential given Cretaceous and Jurassic rights

**Key statistics**

<table>
<thead>
<tr>
<th>Units</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net acres</td>
<td>~720,000</td>
</tr>
<tr>
<td>Proved + probable + future drilling opportunities</td>
<td>~630</td>
</tr>
<tr>
<td>Average working interest</td>
<td>~71</td>
</tr>
<tr>
<td>Net operated processing capacity</td>
<td>~265</td>
</tr>
<tr>
<td>2017F production</td>
<td>BOE/d 37,000</td>
</tr>
<tr>
<td>% oil / liquids</td>
<td>18</td>
</tr>
<tr>
<td>2017F capex</td>
<td>$ millions 60</td>
</tr>
</tbody>
</table>

Note: 2017F production and capital expenditures assume a January 1, 2017 effective date.
Clearwater asset overview

Asset overview

- Significant horizontal development potential across Spirit River, Cardium, and Glauconitic
- Meaningful offsetting industry activity in recent years despite limited capitalization of the acquired Clearwater assets
- Infrastructure ownership results in attractive operating cost structure with capacity to support near-term growth

Key statistics

<table>
<thead>
<tr>
<th>Units</th>
<th>Statistic</th>
<th>Net acres</th>
<th>~840,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net acres</td>
<td>acres</td>
<td>~840,000</td>
<td></td>
</tr>
<tr>
<td>Proved + probable + future drilling opportunities</td>
<td>#</td>
<td>~540</td>
<td></td>
</tr>
<tr>
<td>Average working interest</td>
<td>%</td>
<td>~68</td>
<td></td>
</tr>
<tr>
<td>Net operated processing capacity</td>
<td>MMcf/d</td>
<td>~125</td>
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</tr>
<tr>
<td>2017F production</td>
<td>BOE/d</td>
<td>37,000</td>
<td></td>
</tr>
<tr>
<td>% oil / liquids</td>
<td>%</td>
<td>36</td>
<td></td>
</tr>
<tr>
<td>2017F capex</td>
<td>$ millions</td>
<td>55</td>
<td></td>
</tr>
</tbody>
</table>

Note: 2017F production and capital expenditures assume a January 1, 2017 effective date.
Deep Basin infrastructure overview

Asset overview

- ~1.4 BCF/d of net natural gas processing capacity and significant associated gathering infrastructure
- Infrastructure footprint spans the Deep Basin
- Ownership and control underpins operational flexibility
- Excess processing capacity supports near-term development potential
- Third party processing revenues support competitive cost advantage

Key statistics

<table>
<thead>
<tr>
<th>Units</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operated and non-operated assets</td>
<td>#</td>
</tr>
<tr>
<td>Avg. working interest of operated facilities</td>
<td>%</td>
</tr>
<tr>
<td>Total net processing capacity</td>
<td>MMcf/d</td>
</tr>
</tbody>
</table>

Key facilities

<table>
<thead>
<tr>
<th>Facility</th>
<th>Units</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elmworth 01-08-70-11W6</td>
<td>Net MMcf/d</td>
<td>395</td>
</tr>
<tr>
<td>Noel B-059-D/093-9-08</td>
<td>Net MMcf/d</td>
<td>150</td>
</tr>
<tr>
<td>Peco 6-19-73-08W6</td>
<td>Net MMcf/d</td>
<td>69</td>
</tr>
</tbody>
</table>
## Supplemental terms of the transaction

<table>
<thead>
<tr>
<th>Contingent payment terms</th>
<th>Vendor take-back terms</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Based on a 5-year time horizon, with a threshold price of $52.00/bbl Western Canadian Select (“WCS“)</td>
<td>• ConocoPhillips has agreed to receive 208 million common shares of Cenovus</td>
</tr>
<tr>
<td>• Calculation based on $6.0 million per quarter multiplied by the difference between the average WCS price and the threshold price of $52.00/bbl</td>
<td>• Share consideration reinforces ConocoPhillips’ confidence in the strategic rationale of this transaction and future outlook for Cenovus</td>
</tr>
<tr>
<td>• Payments and calculations are done on a quarterly basis</td>
<td>• ConocoPhillips is bound by the terms in the investor agreement, including a restriction on its ability to sell or hedge its shares for a minimum period of six months from the closing date of the transaction</td>
</tr>
<tr>
<td>• Contingent payments will be reduced during periods of material production outages</td>
<td>• ConocoPhillips has agreed to vote with Cenovus management voting recommendations or abstain from voting and is restricted from nominating new members to Cenovus’s Board of Directors</td>
</tr>
<tr>
<td>• Cenovus retains 80-85% of the benefit above the trigger price based on current FCCL production volumes</td>
<td></td>
</tr>
</tbody>
</table>
Investor relations contacts

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cenovus.com
A final base shelf prospectus containing important information relating to the securities described in this presentation has been filed with the securities regulatory authorities in each of the provinces and territories of Canada. A copy of the final base shelf prospectus, any amendment to the final base shelf prospectus and any applicable prospectus supplement is required to be delivered with this presentation.

This presentation does not provide full disclosure of all material facts relating to the securities offered. Investors should read the final base shelf prospectus, any amendment and any applicable prospectus supplement for disclosure of those facts, especially risk factors relating to the securities offered, before making an investment decision.

The issuer has filed a registration statement (including a final base shelf prospectus) with the United States Securities and Exchange Commission ("SEC"), which has become effective under the United States Securities Act of 1933, as amended, for the offering to which this communication relates. Preliminary and final prospectus supplements describing the offering will also be filed with the securities regulatory authorities in each of the provinces and territories of Canada and with the SEC. Before you invest, you should read the prospectus in that registration statement and the preliminary prospectus supplement and other documents the issuer has filed with the SEC for more complete information about the issuer and this offering. You may get any of these documents for free by visiting EDGAR on the SEC website at www.sec.gov or via SEDAR at www.sedar.com. Alternatively, the issuer, any underwriter or any dealer participating in the offering will arrange to send you the prospectus and the prospectus supplement if you request it in the U.S. from J.P. Morgan Securities LLC, via Broadridge Financial Solutions, 1151 Long Island Avenue, Edgewood, New York 11717; Phone: (866) 803-9204; or Email: prospectus-eq-fil@jpmchase.com, or RBC Capital Markets, LLC, 200 Vesey Street, 8th Floor, New York, NY 10281-8096, Attention: Equity Syndicate; or by email: equityprospectus@rbccm.com, or in Canada from RBC Dominion Securities Inc., Attn: Simon Yeung, Distribution Centre, RBC Wellington Street, 8th Floor, 180 Wellington St. W., Toronto, Ontario, M5J 0C2 (Tel: 416-942-5349; email: Distribution.RBCDS@rbccm.com).

FORWARD-LOOKING INFORMATION

This presentation contains certain forward-looking statements and other information (collectively "forward-looking information") about Cenovus' current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "estimate", "target", "to be", "future", "IP", "expect", "potential", "capacity", "will", "capable", "horizon", "contingent", "strategy", "outlook", "pro forma", "illustrative" or similar expressions and includes suggestions of future outcomes, including statements about: the planned acquisition (the "Acquisition") of a 50% working interest in the FCCL Partnership (the "FCCL Assets") and the majority of ConocoPhillips' western Canadian conventional assets, including ConocoPhillips' exploration and production assets and related infrastructure and development assets, and all of ConocoPhillips' interest in petroleum and natural gas rights and oil and natural gas leases within a certain area of mutual interest northwest of Foster Creek (collectively, the "Deep Basin Assets" and together with the FCCL Assets, the "Assets"), including the expected closing thereof; the anticipated benefits to us of the Acquisition, including the effect on Adjusted Funds Flow, cash flow, dividend growth and dividend level; our pro forma financial, operating and regulatory resources, anticipated drilling locations, drilling inventories and other factors, and production estimates after completion of the Acquisition; the midstream gathering, processing and transportation arrangements to be acquired and assumed by us in connection with the Acquisition; the availability and repayment of the revolving credit facility and the fully committed bridge financing; a portion of the bridge financing through the issuance of the Common Shares pursuant to the bought deal; replacement, refinancing or repayment of the long term debt bridge facility through the issuance by Cenovus of debt securities; anticipated disposition of certain assets and the expected proceeds thereof; a portion of such dispositions to amounts owing under the asset sale bridge facility; potential asset dispositions and anticipated impacts to us; the anticipated effect of the Acquisition on Cenovus' credit ratings; the anticipated effect of the Acquisition on staffing; Cenovus' cost containment strategies; our expectation of satisfying payment obligations as they become due; planned capital expenditures, including the amount, timing and financing thereof; our annual capital investment forecasts and plans with respect thereto; the techniques expected to be used to recover reserves and forecasts of the timing thereof; our expected recovery of income taxes; our expected future production, including the timing, stability or growth thereof; our expected reserves, contingent and prospective resources and related information, including future net revenue and future development costs; oil sands sustaining capital costs and the impact on net present value of oil sands projects; over years of steady capital investment and production growth; our expected ability to maintain our financial resilience and various plans and strategies with respect thereto; forecast cash savings and sustainability initiatives; our expectations for 2017 and future years; our expectations for broadening market access; our expectations for improving cost structures, forecast cost savings and the sustainability thereof; our dividend plans and strategy; the future impact of the Acquisition on our financial statements and results of operations; our ability to achieve and sustain cost reductions; our ability to obtain necessary regulatory and partner approvals; our ability to implement capital projects or stages thereof in a successful and timely manner; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities. The information contained on our website is not incorporated by reference into this presentation. The reference to our website is intended to be an inactive textual reference.

Advisory

Advisory
FORWARD-LOOKING INFORMATION CONTINUED

The forward looking information in this presentation also includes financial outlook regarding Cenovus and other forward looking metrics (including production and financial oil and gas related metrics) relating to the Acquisition and the Assets, namely with respect to: the projected impact of lowering sustaining capital, including on the net present value of our assets; our estimates regarding the Field Level Break Even (as defined herein) WTI price for our oil sands assets; our projections for and expectations relating to our Free Funds Flow; our projected capital expenditures; projections related to drilling locations and other opportunities, IRR, NPV, Payout, F&D, Recycle Ratio and Capital Efficiency (each as defined herein)metrics for wells drilled in respect of the Deep Basin Assets; our expectations regarding the impact of the transition on Adjusted Funds Flow, Adjusted Funds Flow per Common Share, upstream operating costs per BOE, general and administrative ("G&A") expenses per BOE, Free Funds Flow, operating costs, G&A and capital expenditures and our targeted Debt (and Net Debt) to Adjusted EBITDA and Debt (and Net Debt) to Capitalization ratios (as each defined herein). See also "Drilling Locations" and "Conventions and Industry Terminology" for important information regarding our disclosure of drilling locations and other opportunities and the other oil and gas metrics referred to above.

Unless otherwise specifically stated or the context dictates otherwise, the financial outlook and other forward looking metrics contained in this presentation, in addition to the generally applicable assumptions described above, are based on the following specific assumptions, as applicable: (i) WTI prices averaging US$50.00 in 2017, 2018, and 2019; (ii) Brent prices averaging US$52.25 in 2017, 2018, and 2019; (iii) NYMEX natural gas prices averaging US$3.00 in 2017, 2018, and 2019; (iv) AECO natural gas prices averaging $3.07 in 2017, 2018, and 2019; (v) the exchange rate for the conversion of one U.S. dollar into Canadian dollars averaging $1.33 in 2017, 2018, and 2019; (vi) the pricing differential between WCS and WTI averaging US$14.50 in 2017, 2018, and 2019; (vii) Chicago 3-2-1 Crack Spread averaging US$15.00/bbl in 2017, 2018, and 2019; (viii) the successful completion of our forecast capital expenditure and development plans as outlined in this presentation (including favourable drilling results and successful completion of major projects on time and on budget); (ix) the alignment of realized WCS prices and WCS prices as calculated under the contingent payment agreement; (x) overall production rates for 2017, 2018 and 2019 being in line with our expectations as outlined in this presentation; (xi) royalty rates in Alberta, Saskatchewan and British Columbia remaining unchanged from the currently announced rates for 2017, 2018 and 2019; and (xii) operating and G&A costs per BOE being in line with our expectations as outlined in this presentation.

Unless otherwise specifically stated or the context dictates otherwise, the financial outlook and forward looking metrics in this presentation, in addition to the generally applicable assumptions described above, do not include or account for the effects or impacts of planned asset sales.

The risk factors and uncertainties that could cause Cenovus’ actual results to differ materially include: possible failure by us to realize the anticipated benefits of, and synergies from, the Acquisition; our inability to complete the Acquisition on the terms contemplated by the Acquisition Agreement or at all; possible failure to access or implement some or all of the technology necessary to efficiently and effectively operate our assets (including, but not limited to, the Assets) and achieve and sustain future cost reductions; volatility of and other assumptions regarding commodity prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the efficiency of our liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; possible lack of alignment of realized WCS prices and WCS prices as calculated under the contingent payment agreement; product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of Debt (and Net Debt) to Adjusted EBITDA as well as Debt (and Net Debt) to Capitalization; our ability to access various sources of debt and equity capital on reasonable and cost effective terms; our ability to secure adequate and cost-effective product transportation; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; accuracy of our reserves, resources, future production and future net revenue estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; risks associated with climate change; the timing and the costs of well and pipeline construction; our ability to secure adequate and cost-effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; changes in our labour relationships; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in general economic, market and business conditions; political and economic conditions in the countries in which we operate or supply; occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Statements relating to "reserves" and "resources" are deemed to be forward looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward looking information.
Purchasers should not place undue reliance on the forward looking information contained in this presentation, the final base shelf prospectus, any applicable prospectus supplement or the documents incorporated by reference therein, as actual results achieved will vary from the forward looking information provided in this presentation, the final base shelf prospectus, any applicable prospectus supplement and the documents incorporated by reference therein, and the variations may be material. We make no representation that actual results achieved will be the same in whole or in part as those set out in the forward looking information. Furthermore, the forward looking information contained in this presentation, the final base shelf prospectus, any applicable prospectus supplement and the documents incorporated by reference therein is made as of the date of this presentation or as of the date specified in any applicable prospectus supplement or the documents incorporated by reference therein, as the case may be.

The purpose of the financial outlook in this presentation is to provide management’s expectations of the effects of the offering of securities and/or the Acquisition, as applicable. Except as required by applicable securities law, we undertake no obligation to update publicly or otherwise revise any forward looking information or the foregoing list of factors affecting those statements, whether as a result of new information, future events or otherwise or the foregoing lists of factors affecting this information. For a discussion of Cenovus’ material risk factors, see “Risk Factors” in the base shelf prospectus, the discussion of risk factors in any applicable prospectus supplement, “Risk Factors” in the company’s annual information form or Form 40-F for the year ended December 31, 2016 and “Risk Management” in our management discussion and analysis of financial condition and results of operations for the year ended December 31, 2016, each available on the company’s website at Cenovus.com, on SEDAR at sedar.com, and on EDGAR at sec.gov.

**NON-GAAP MEASURES AND ADDITIONAL SUBTOTAL**

The following measures do not have a standardized meaning as prescribed by International Financial Reporting Standards (“IFRS” or “GAAP”) and therefore are considered non-GAAP measures. You should not consider these measures in isolation or as a substitute for analysis of our results as reported under IFRS. These measures are defined differently by different companies in our industry. These measures may not be comparable to similar measures presented by other issuers.

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold. Netbacks reflect Cenovus’ margin on a per-barrel basis of unbленded bitumen and crude oil. As such, the bitumen and crude oil sales, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the bitumen and heavy oil to reduce its thickness in order to transport it to market. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”). See Appendix “A” in the prospectus supplement for a reconciliation of Netback to the applicable line items of the Pro Forma Operating Statement.

Adjusted Funds Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company’s ability to finance its capital programs and meet its financial obligations. Adjusted Funds Flow is defined as Cash From Operating Activities less capital investment. Adjusted Funds Flow is used to measure management’s ability to meet its financial obligations and as a measure of its overall financial strength.

Net Debt is a non-GAAP measure defined as Debt net of cash and cash equivalents. Adjusted EBITDA is a non-GAAP measure that we define as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets, revaluation gain and other income (loss), net, calculated on a trailing 12-month basis. Net debt to Adjusted EBITDA is used to steward our overall debt position and as a measure of our overall financial strength.

Capitalization is a non-GAAP measure that we define as Debt plus shareholders’ equity. Net Debt to Capitalization is defined as net debt divided by net debt plus shareholders’ equity.

Operating Margin is an additional subtotal found in Note 1 of the unaudited annual comparative consolidated financial statements and auditor’s report thereon for the year ended December 31, 2016 and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities.

**OIL AND GAS INFORMATION**

The estimates of reserves and resources data and related information contained in this presentation were prepared by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (“NI 51-101”). The SEC definitions of proved and probable reserves are different from the definitions contained in NI 51-101; therefore, proved and probable reserves disclosed herein in compliance with NI 51-101 may not be comparable to U.S. standards. The U.S. Securities and Exchange Commission (the “SEC”) requires U.S. oil and gas reporting companies, in their filings with the SEC, to disclose only proved reserves after the deduction of royalties and production due to others but permits the optional disclosure of probable and possible reserves.
Capital Efficiency is relevant and useful to investors because it shows the illustrative economics in respect of wells we anticipate drilling in respect of the Deep Basin Assets over the first 365 days of production of such wells.

References in this presentation to "crude oil" means "bitumen", "heavy crude oil", "light crude oil" and "medium crude oil" as defined in NI 51-101; references to "natural gas" means, collectively, "conventional natural gas" as defined in NI 51-101; "shale gas" as defined in NI 51-101, "coal bed methane" as defined in Canadian Securities Administrators Staff Notice 51-324 Glossary to NI 51-101 – Standards of Disclosure for Oil and Gas Activities; references to "NGLs" means "natural gas liquids" as defined in NI 51-101; references to "heavy oil" means "heavy crude oil" as defined in NI 51-101, and references to "liquids" means crude oil and NGLs.

Cenovus’ ability to drill and develop these locations and opportunities and the drilling locations on which Cenovus actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, capital and operating costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, net price received for commodities produced, regulatory approvals and regulatory changes. As a result of these uncertainties, there can be no assurance that the potential future drilling locations and opportunities Cenovus has identified will ever be drilled or if Cenovus will be able to produce oil, NGL or natural gas from these or any other potential drilling locations or opportunities. As such, Cenovus’ actual drilling activities may differ materially from those presently identified, which could adversely affect Cenovus’ business. While certain of the identified un-booked drilling opportunities have been de-risked by drilling existing wells in relatively close proximity to such un-booked drilling opportunities, some of the other un-booked drilling opportunities are farther away from existing wells where Cenovus management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled and, if drilled, there is further uncertainty that such wells will result in additional proved or probable reserves or production.

Conventions and Industry Terminology

References in this presentation to "crude oil" means "bitumen", "heavy crude oil", "light crude oil" and "medium crude oil" as defined in NI 51-101; references to "natural gas" means, collectively, "conventional natural gas" as defined in NI 51-101; "shale gas" as defined in NI 51-101, "coal bed methane" as defined in NI 51-101, "solution gas" as defined in Canadian Securities Administrators Staff Notice 51-324 Glossary to NI 51-101 – Standards of Disclosure for Oil and Gas Activities; references to "NGLs" means "natural gas liquids" as defined in NI 51-101; references to "heavy oil" means "heavy crude oil" as defined in NI 51-101, and references to "liquids" means crude oil and NGLs.

Types of wells described in this presentation are based on actual drilling results from such wells to date.

"Capital Efficiency" is defined as initial well costs divided by IP365. Initial well costs include the average expected costs to drill, complete, and tie-in a single well and exclude costs associated with early stage appraisal activity such as seismic, stratigraphic test drilling, and other infrastructure. Capital Efficiency does not have any standard meaning prescribed by IFRS or the COGE Handbook and therefore may not be comparable with the calculation of similar measures for other entities. We believe that the presentation of Capital Efficiency is relevant and useful to investors because it shows the illustrative economics in respect of wells that may be comparable to those we anticipate drilling in respect of the Deep Basin Assets over the first 365 days of production of such wells.
OIL AND GAS INFORMATION

"Decline rate" is defined as the rate at which proved developed producing reserves are expected to naturally decline according to the evaluation by our independent qualified reserves evaluator.

"F&D" is defined as expected initial well costs divided by forecasted average recovery based on type curve analysis. F&D does not have any standard meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. We believe that the presentation of F&D is relevant and useful to investors because it shows the illustrative well-level finding and development cost economics in respect of wells that may be comparable to those we anticipate drilling in respect of the Deep Basin Assets.

"Field Level Break-Even" is the approximate benchmark WTI oil price at which realized bitumen revenues cover cash costs, including royalties, transportation and blending, and operating costs. Field Level Break-Even does not have any standard meaning prescribed by IFRS or the COGE Handbook and therefore may not be comparable with the calculation of similar measures for other entities. We believe that the presentation of Field Level Break-Even is relevant and useful to investors because it provides an illustrative field level break-even economic WTI oil price in respect of our oil sands projects.

"IP365" is defined as the estimated average producing day rate over the first 365 days of a type curve forecast based on analysis of existing wells having characteristics believed to be similar as the identified drilling opportunities.

"IRR" is defined as the interest rate at which the net present value of all future cash flows from a well equal zero. IRR does not have any standard meaning prescribed by IFRS or the COGE Handbook and therefore may not be comparable with the calculation of similar measures for other entities. We believe that the presentation of IRR is relevant and useful to investors because it shows illustrative well-level economics in respect of wells that may be comparable to those we anticipate drilling in respect of the Deep Basin Assets.

"NPV" is defined as the difference between the present value of projected cash inflows and the present value of projected cash outflows. NPV does not have any standard meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. We believe that the presentation of NPV is relevant and useful to investors because it presents the relative monetary significance of wells that may be comparable to those we anticipate drilling in respect of the Deep Basin Assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. NPV, however, does not purport to present the fair value of our oil, natural gas and NGLs reserves.

"Payout" is the number of years required for projected after-tax cash inflows to exceed initial well costs. Payout does not have any standard meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. We believe that the presentation of Payout is relevant and useful to investors because it presents an illustration of the time length to profitability of wells that may be comparable to those we anticipate drilling in respect of the Deep Basin Assets.

"Recycle Ratio" is defined as estimated total operating margin over the life of a well divided by initial well costs. Recycle Ratio does not have any standard meaning prescribed by IFRS or the COGE Handbook and therefore may not be comparable with the calculation of similar measures for other entities. We consider Recycle Ratio to be a useful supplemental measure of operating performance and profitability in respect of wells that may be comparable to those we anticipate drilling in respect of the Deep Basin Assets.

"Well Costs" include the average expected costs to drill, complete, and tie-in a single well.

Material assumptions used in calculating, and the risks applicable to, the above metrics in this presentation are consistent with those detailed above under "Forward-Looking Information".

For more information see the sections titled "Note Regarding Reserves and Resources Disclosure", "Drilling Locations" and "Conventions and Industry Terminology" in the prospectus supplement.

Production Presentation Basis
Cenovus presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. Any ticker symbols noted in this presentation are in respect of companies listed on Toronto Stock Exchange.

All dollar amounts in this presentation are in Canadian dollars unless otherwise indicated.

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