# A different kind of oil sands

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# A different kind of oil sands

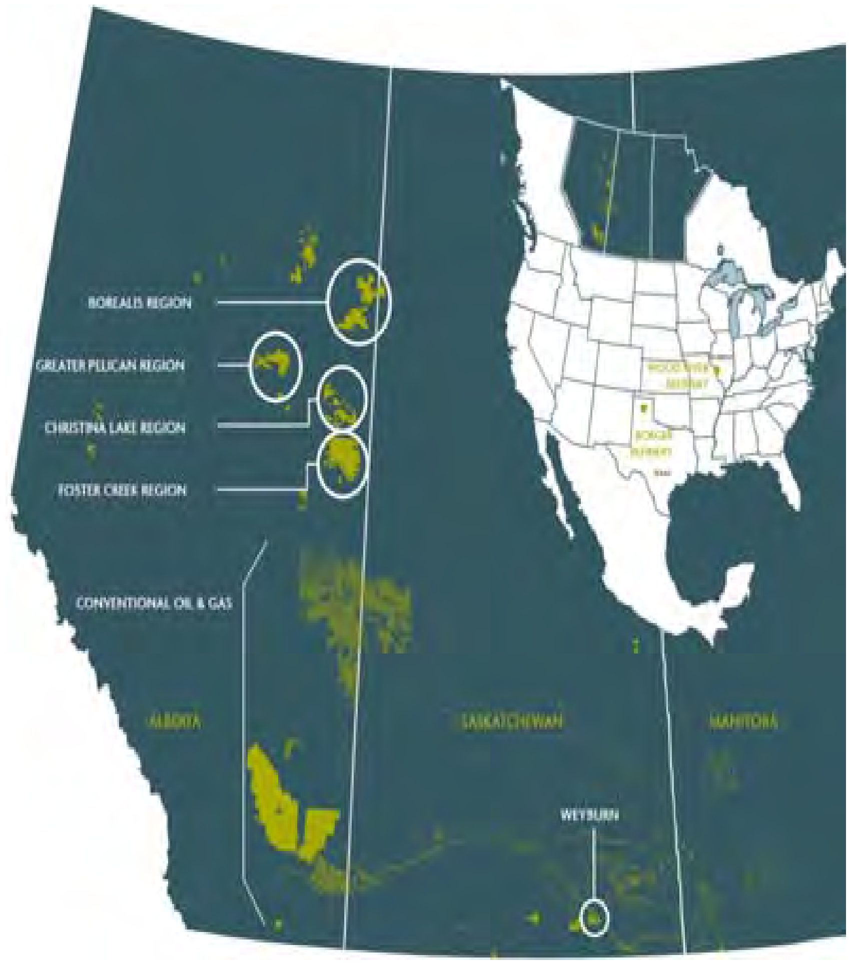
## Focus on total shareholder return & building long-term value

- Top-tier oil sands portfolio generates predictable, reliable growth
- Strong project execution & innovation drives performance
- Strategic integration & market access enhances cash flow
- Solid & conservative financial position provides flexibility

# Strong integrated portfolio

## TSX, NYSE | CVE

| | |
|---|---|
| Enterprise value | C$25 billion |
| Shares outstanding | 829 MM |
| 2015F production | |
| Oil & NGLs | 204 Mbbls/d |
| Natural gas | 438 MMcf/d |
| 2014 proved & probable reserves | 3.9 BBOE |
| Bitumen | |
| Economic contingent resources* | 9.3 Bbbls |
| Discovered bitumen initially in place* | 93 Bbbls |
| Lease rights** | 1.5 MM net acres |
| P&NG rights | 5.6 MM net acres |
| Refining capacity | 230 Mbbls/d net |




Values are approximate. Forecast production based on midpoints of January 28, 2015 guidance. Cenovus land at December 31, 2014. *See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee's behalf.

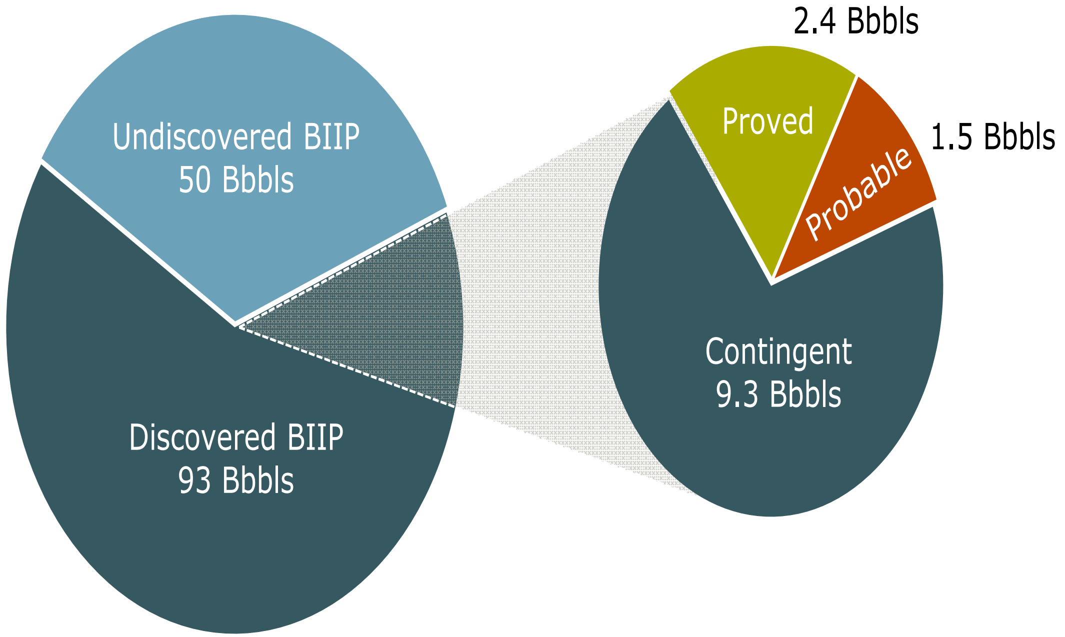
# Advancing strategy; maintaining financial resilience in 2015

- Focusing capital on highest return projects
  - Foster Creek G & Christina Lake F
  - competitive supply costs of US$40-$45/bbl; within projected WTI of US$50.50/bbl
- Slowing longer-term strategic spending while maintaining optionality
  - Narrows Lake, Grand Rapids, Telephone Lake
- Focusing on making sustained operating and capital cost reductions
  - expect ~$200 million in upstream operating, capital and G&A cost savings
- Maintaining financial strength and flexibility to support the business plan
  - capital down 38% from 2014; able to make further reductions should market conditions persist
  - 3% discounted dividend reinvestment plan (DRIP) offered

2015F based on midpoints of guidance. See advisory.

# Established base of high quality resource

- Minimal exploration risk
- Low F&D costs
- Large scale
- Predictable production
- High recovery factors
- Opportunity to advance technology



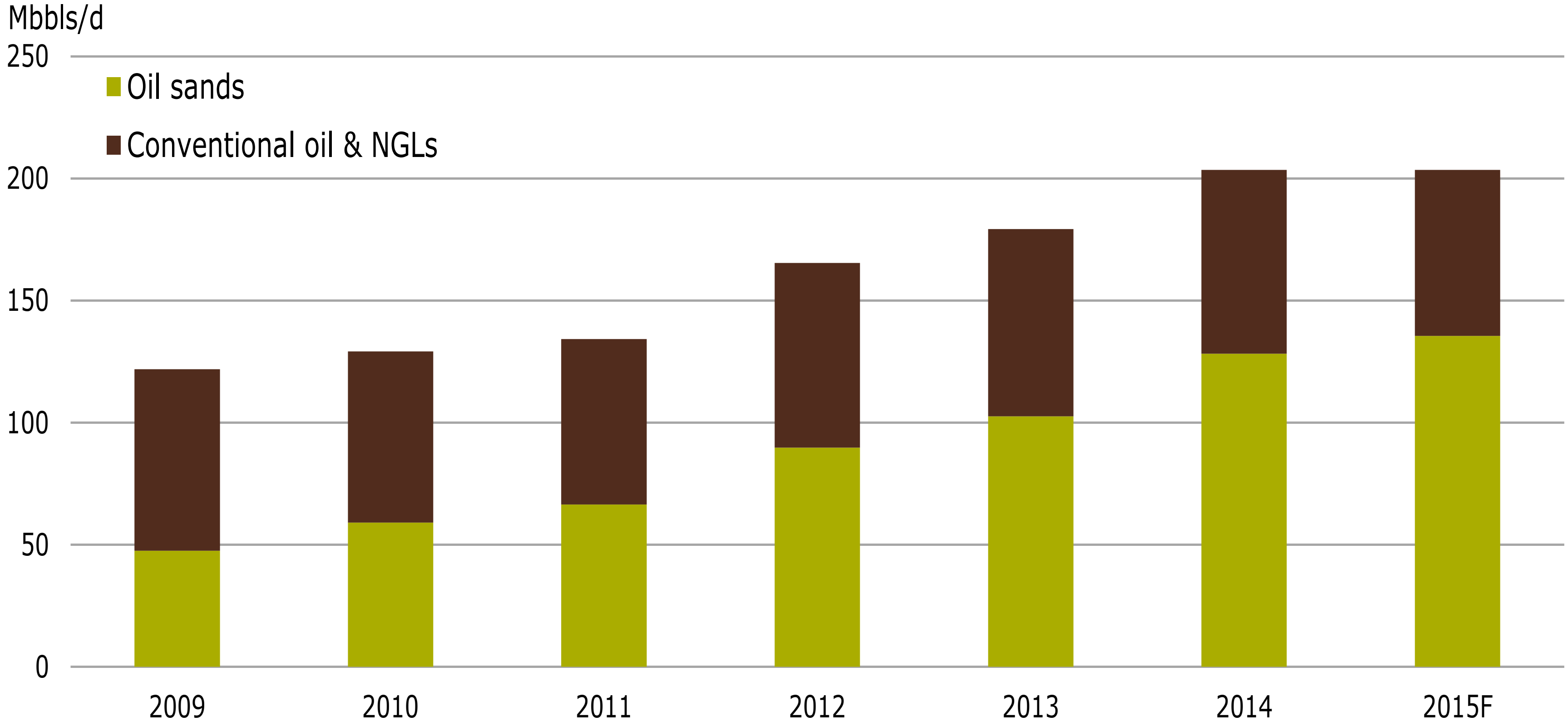

See advisory for information on resource estimates. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.
Discovered/undiscovered allocation at December 31, 2012.

# SAGD portfolio provides development opportunity & growth potential

| | 2P bitumen reserves (Billions of barrels) | Bitumen best estimate economic contingent resources (Billions of barrels) | | | | |
|---|---|---|---|---|---|---|
| | 2014 | 2014 | 2013 | 2012 | 2011 | 2010 |
| Foster Creek | 1.35 | 1.1 | 1.4 | 1.3 | 0.9 | 0.8 |
| Christina Lake core & other areas | 1.41 | 0.7 | 1.1 | 1.2 | 1.1 | 0.8 |
| Narrows Lake | 0.46 | 0.1 | 0.1 | 0.1 | 0.4 | 0.5 |
| Telephone Lake | - | 2.6 | 2.6 | 2.2 | 2.1 | 2.0 |
| Steepbank & East McMurray | - | 2.9 | 2.9 | 2.9 | 2.0 | 0.8 |
| East Borealis | - | 0.2 | 0.2 | 0.2 | - | - |
| Grand Rapids | 0.08 | 1.7 | 1.5 | 1.7 | 1.6 | 1.3 |
| Total contingent resources | | 9.3 | 9.8 | 9.6 | 8.2 | 6.1 |
| Total 2P bitumen reserves | 3.3 | | 2.5 | 2.4 | 1.9 | 1.7 |

Totals may not add due to rounding. For additional information about our economic contingent resources please see the advisory. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

# Executing on our business plan




Adding net production capacity of 40,000 bbls/d at Foster Creek & Christina Lake in 2016 and long-term potential to exceed 500,000 bbls/d by fully developing approved projects

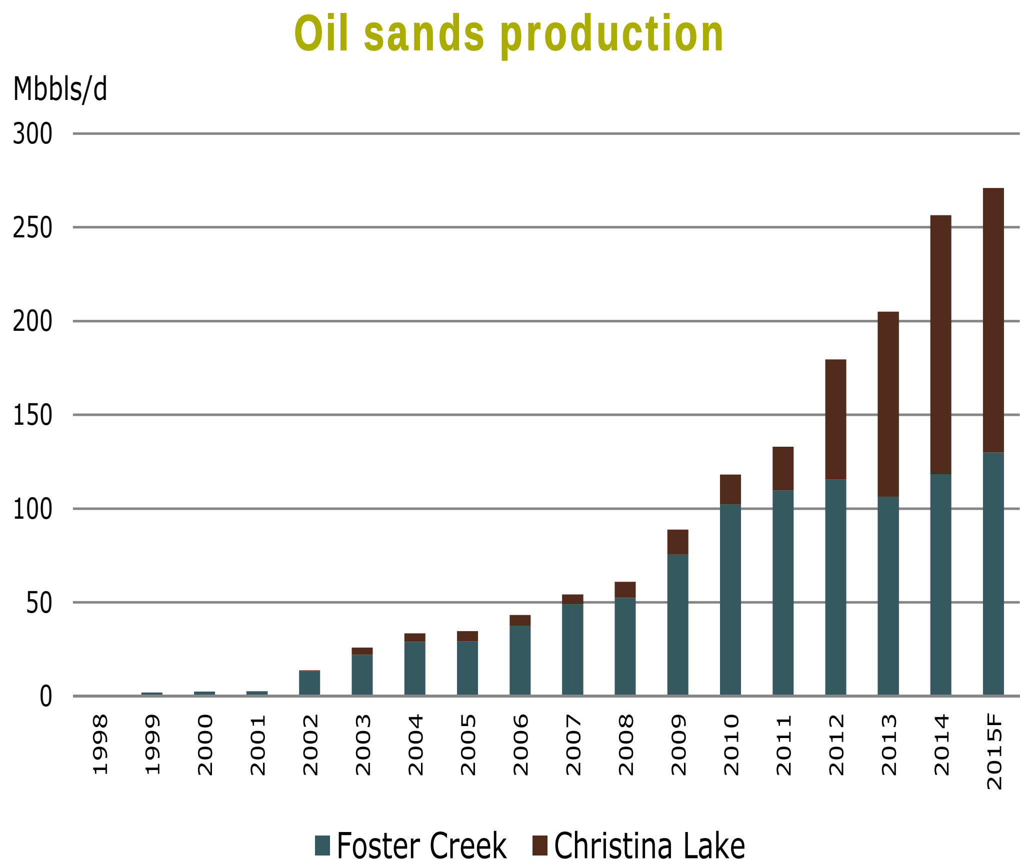
Volumes are shown before royalties and net to Cenovus. 2015F based on midpoints of guidance. Conventional oil includes Pelican Lake. See advisory.

# Oil sands

Our operations include steam-assisted gravity drainage (SAGD) oil sands projects in northern Alberta.

*Shown here are steam generation facilities at our Christina Lake SAGD project, one of our cornerstone oil sands assets.*

# Our manufacturing approach has driven oil sands growth

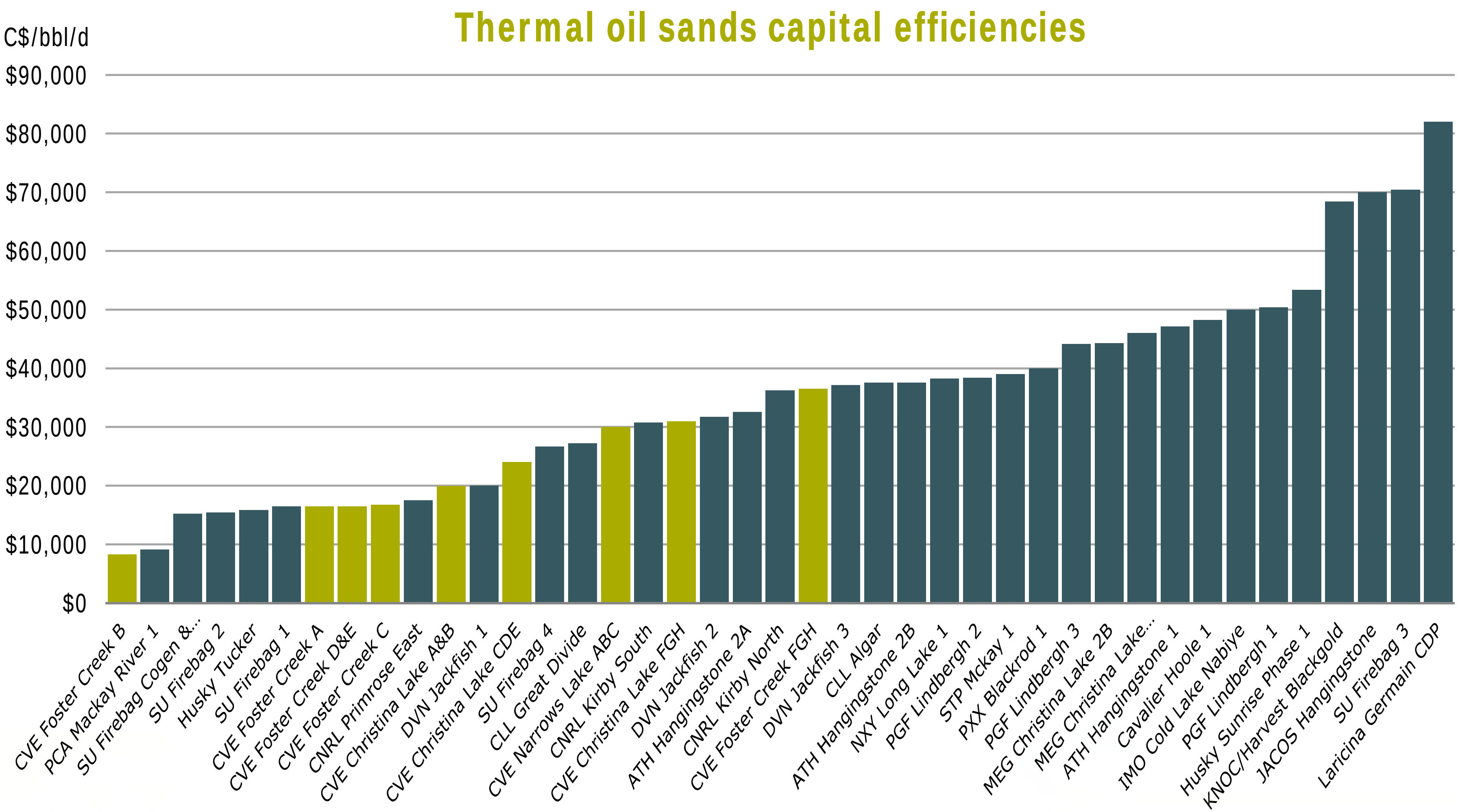

Production is shown before royalties on a gross basis. 2015F based on guidance. See advisory.

# Advancing oil sands projects

| Project phase (first production target) | Expected production capacity[2] (bbls/d) gross |
|---|---|
| **Foster Creek[1,3] A – F (on stream)** | 150,000 |
| G (1H 2016F) | 30,000 |
| H | 30,000 |
| J | 50,000 |
| Potential optimization | 50,000 |
| | |
| **Christina Lake[1] A – E (on stream)** | 138,000 |
| Optimization (Q4 2015F) | 22,000 |
| F (2H 2016F) | 50,000 |
| G | 50,000 |
| H | 50,000 |
| | |
| **Narrows Lake[1]** | |
| A | 45,000 |
| Future phases | 85,000 |
| | |
| **Grand Rapids A** | 8,000 – 10,000 |
| Future phases | 170,000 |
| | |
| **Telephone Lake[4]** | 90,000 |

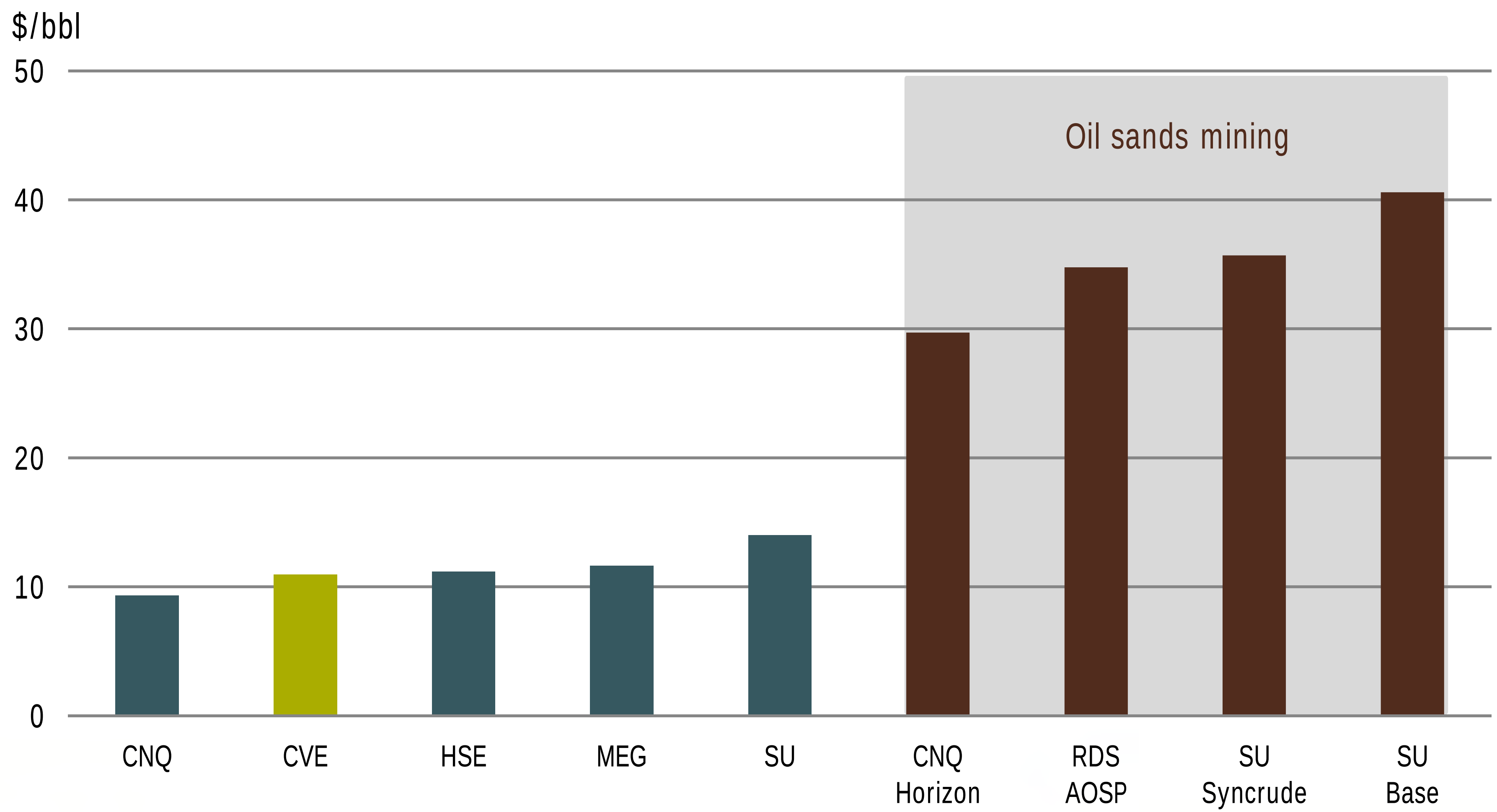
1 Properties 50% owned by ConocoPhillips. Certain phases may be subject to partner approval.
2 Total production capacity indicates projected potential for each project.
3 Each of phases F, G and H are expected to ramp up to 30,000 bbls/d approximately 18 months from first production.
4 Projected total capacity of more than 300,000 bbls/d.

# Proven track record in project development



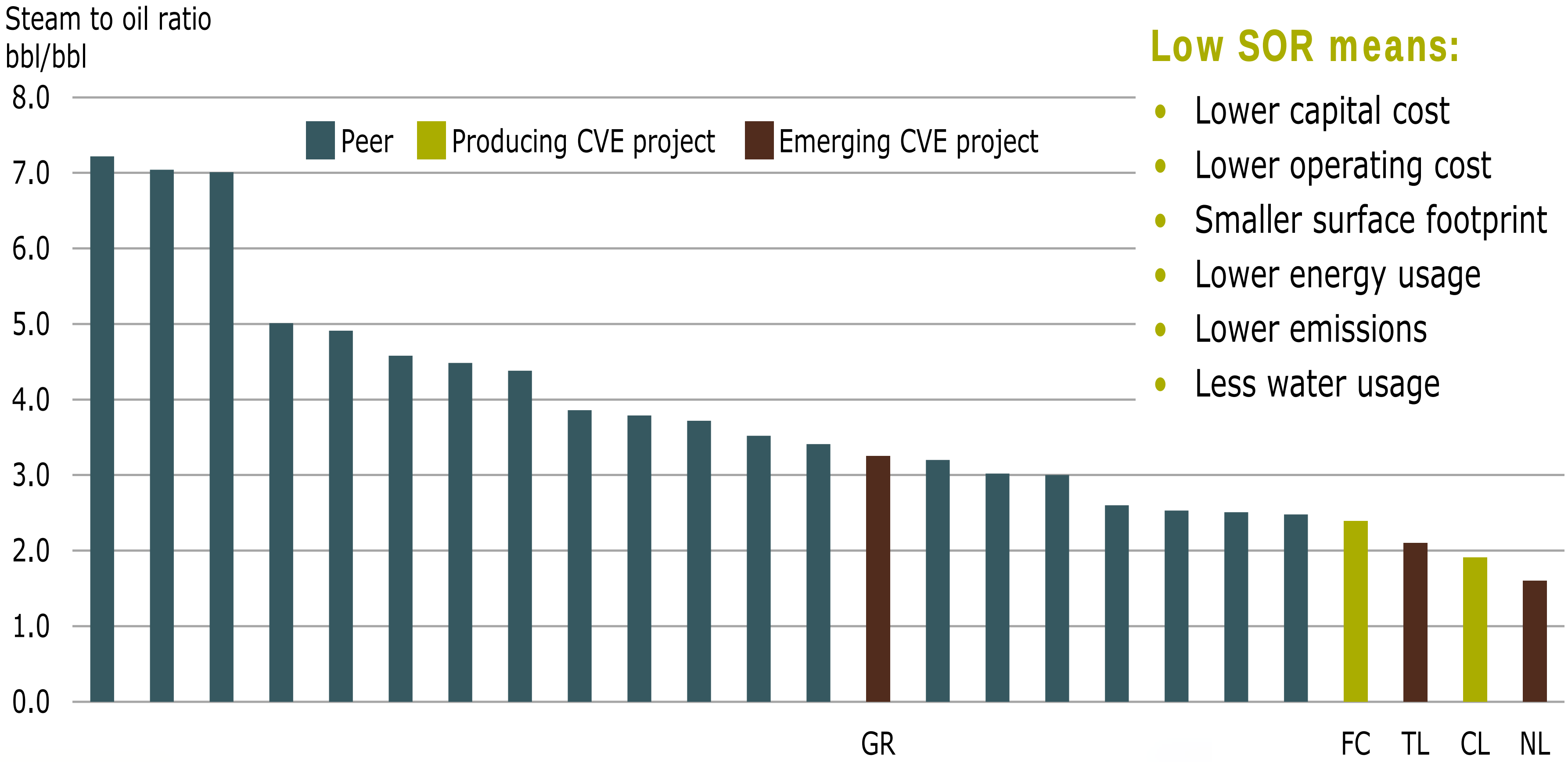

Source: FirstEnergy at February 2015; Cenovus Energy.

# Leading oil sands operating costs




Operating costs per $/bbl reported at Q1 2015.

# SOR reflects resource quality & execution

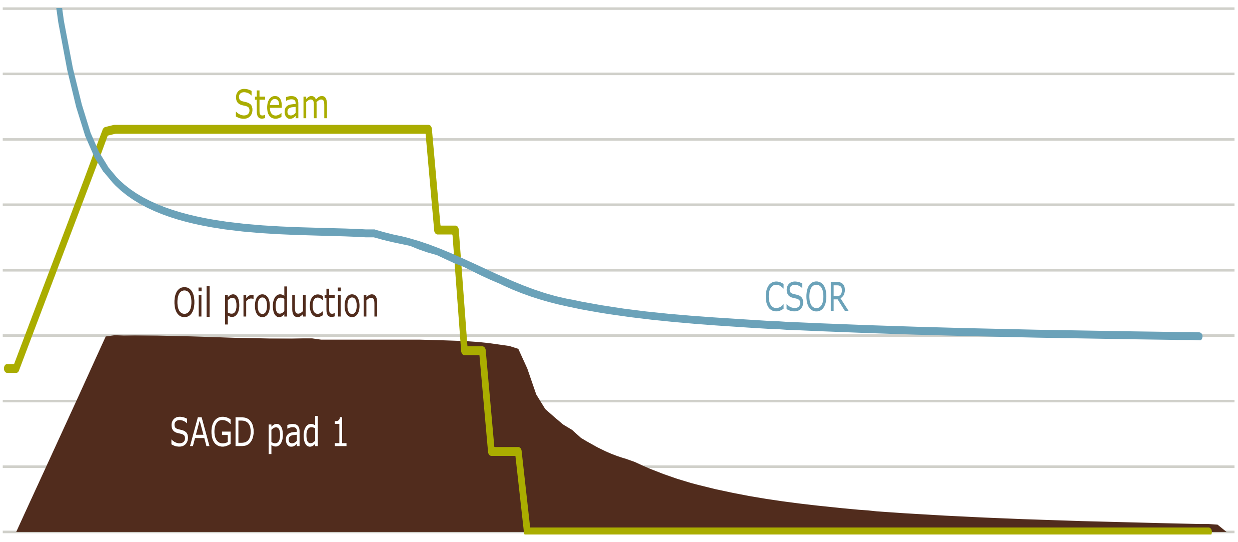



**Low SOR means:**

- Lower capital cost
- Lower operating cost
- Smaller surface footprint
- Lower energy usage
- Lower emissions
- Less water usage

Peer producing projects include: CLL, CNOOC, CNQ, COP, DVN, Grizzly, HSE, IMO, JACOS, MEG, RDS, STO, STP, SU.
Source: IHS, cumulative SOR to February 2015. Cenovus estimates of expected SOR for emerging projects.

# Improving SOR over the life of a SAGD pad

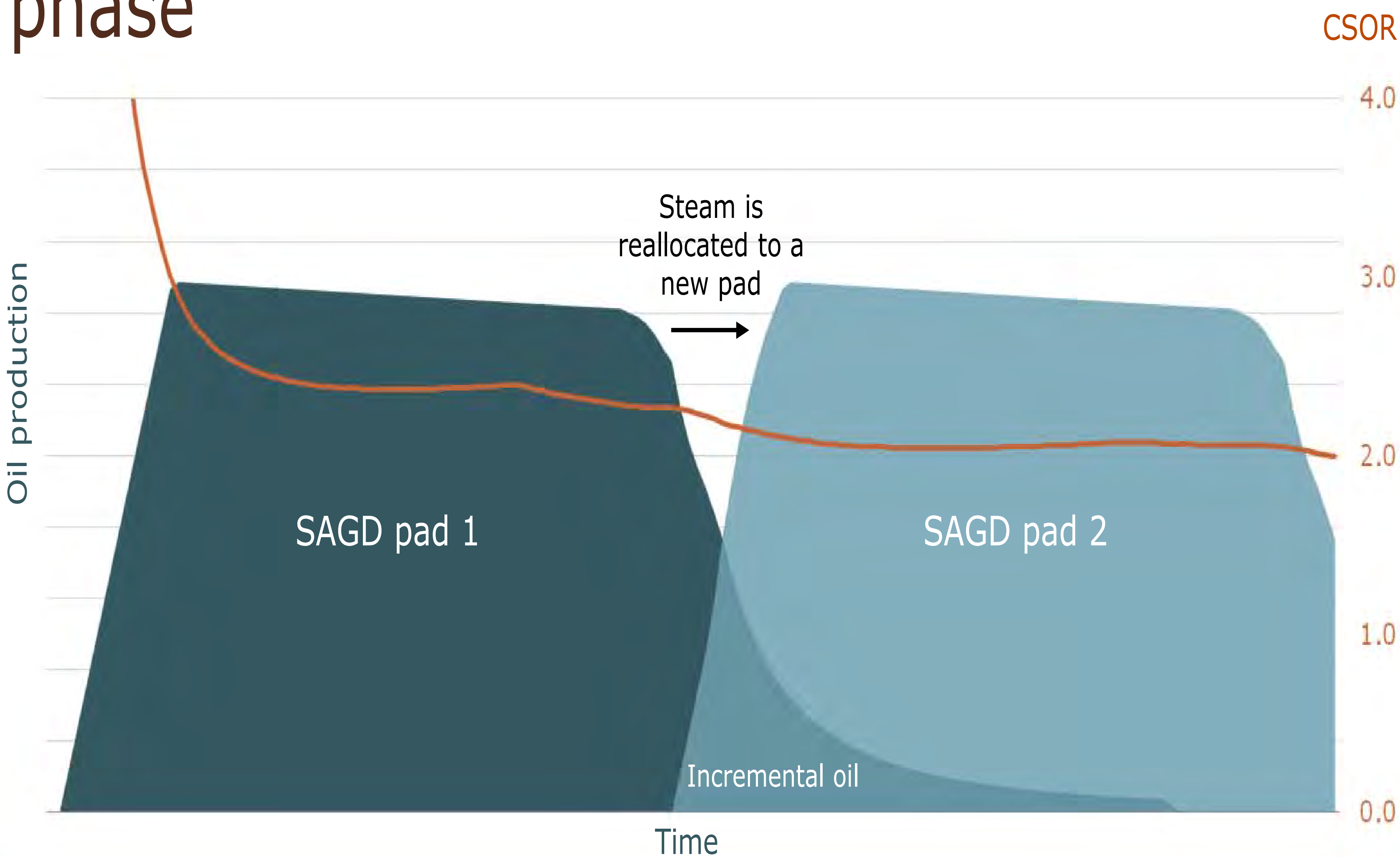



| Start-up | SAGD | Ramp-down | Full blowdown | |
|---|---|---|---|---|
| ~1 year | 5 – 10 years | ~1 year | 5+ years | Time |
| 5% | 5 – 50% | 50 – 70% | | Cumulative recovery factor |
| | | Post steam recovery phase | | |

**Post steam recovery:**

- Steam is reallocated to a new pad
- Oil continues to be produced
- Cumulative steam to oil ratio (CSOR) continues to decrease

# Lowering SOR with the post steam recovery phase

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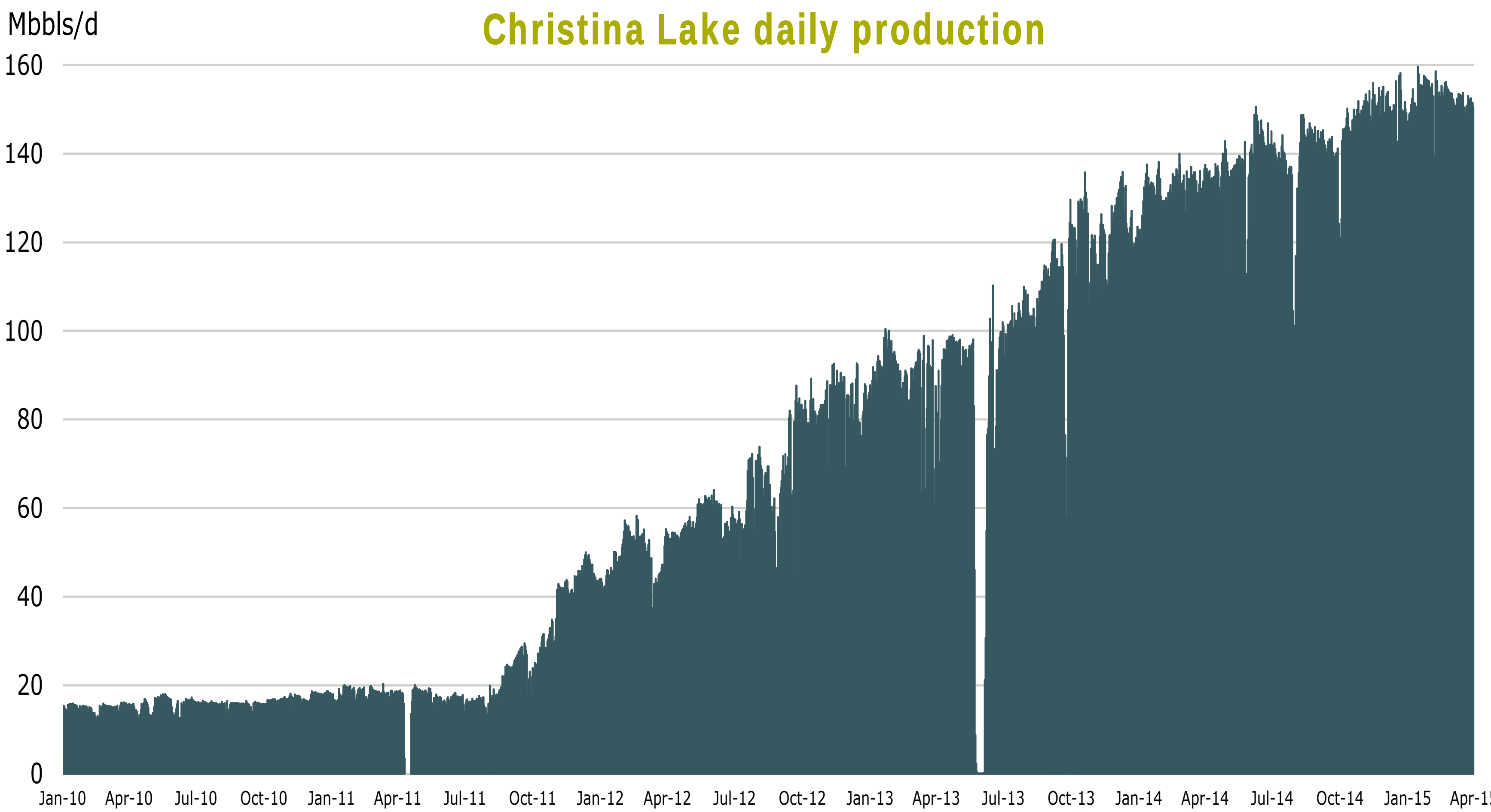
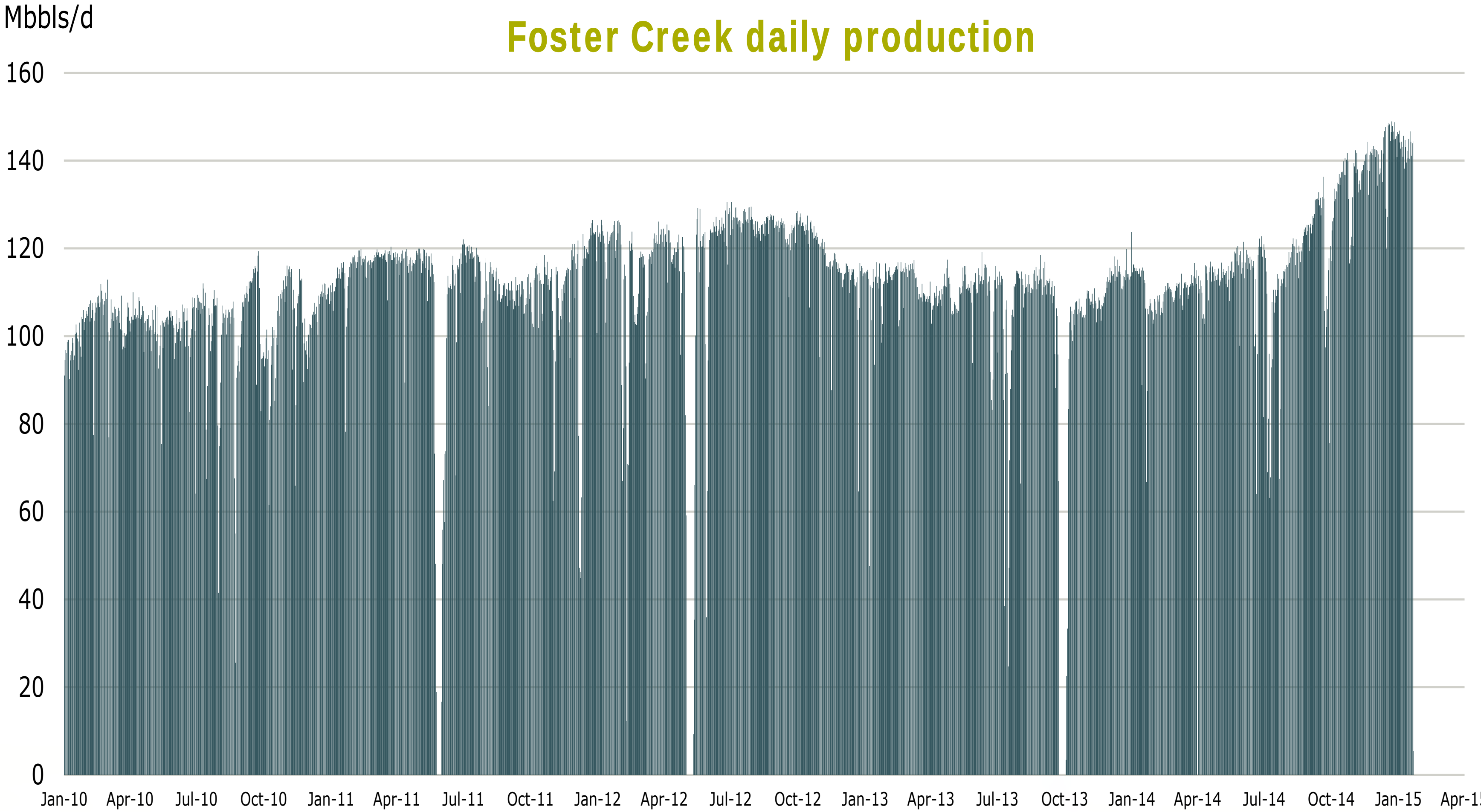
# Demonstrating top tier reservoir performance




Production is shown before royalties on a gross basis.

# Focusing on consistent operations

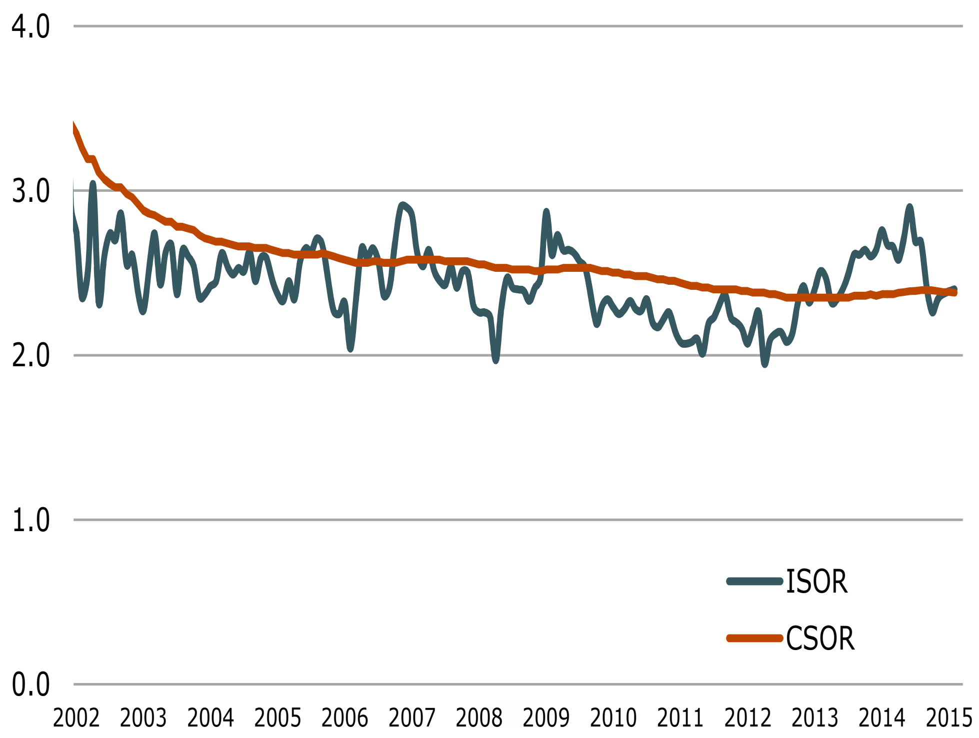



Production is shown before royalties on a gross basis.

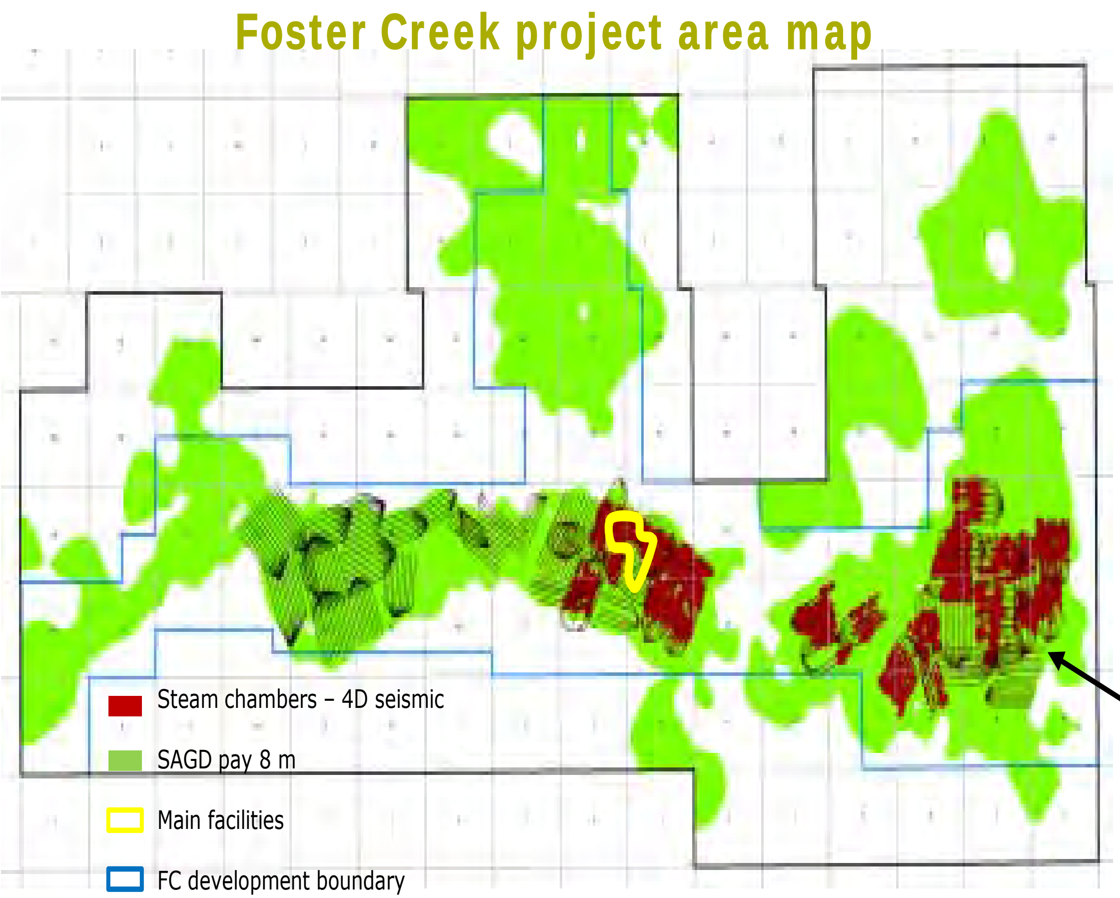
# Managing SOR at Foster Creek

- Optimizing placement of steam across our wells & pads with improved instrumentation
- Placing more pads on blow-down, transferring steam to new pads
- Using Wedge Well™ technology to capture production in areas where conformance is not ideal
- Improving conformance along the well using steam circulation start-ups & flow control devices

## Foster Creek historical SOR performance

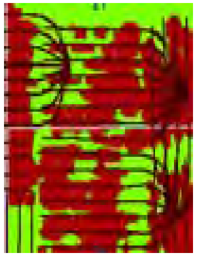


# Understanding reservoir performance at Foster Creek




- Conformance is the ability to inject steam & produce along the full horizontal length of the SAGD well
- Coalescence is a natural progression of SAGD & represents the communication of steam between wells, pads & groups of pads

Foster Creek conformance / coalescence



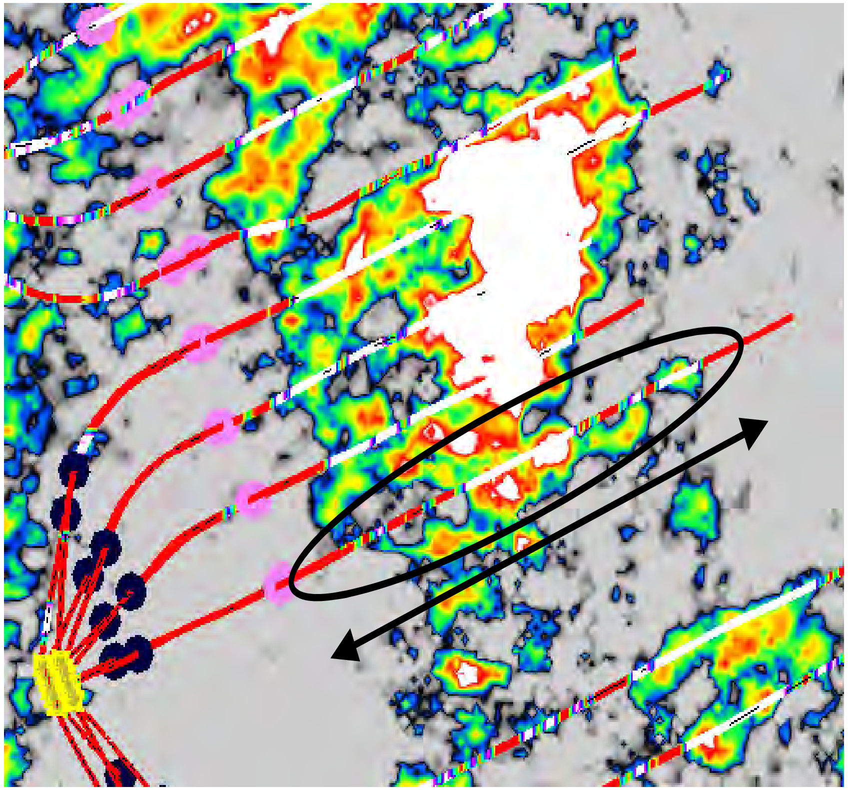
Christina Lake conformance / coalescence*

*Coalescence occurs within 9 months of first production at Christina Lake due to top gas and bottom water in reservoir.

# Well conformance optimizes SOR

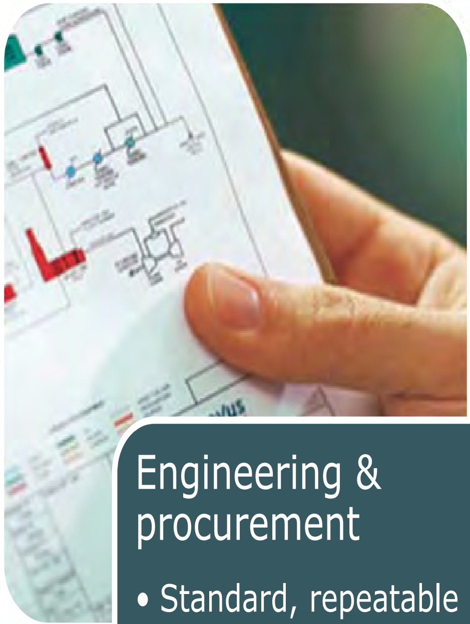
- Once steam chambers coalesce, good well conformance will minimize impact to SOR
- Increased Wedge Well™ technology helps capture oil in existing wells with low conformance
  - currently 89 wells utilizing Wedge Well™ technology at Foster Creek
- Steam circulation at start-up of all new wells & various completion design improvements are expected to improve conformance at Foster Creek
  - implemented ~90 day steam circulation for all new wells, starting with phase F in May 2014

**Foster Creek well pad**



**Improving conformance reduces the impact of coalescence & optimizes SOR**

# Applying manufacturing expertise in SAGD development

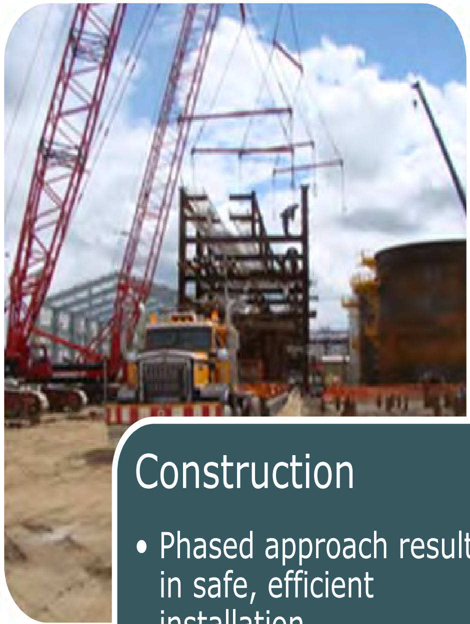


## Engineering & procurement

- Standard, repeatable design
- Outsource detailed engineering
- Standard equipment & services

## Fabrication

- Cenovus-owned & operated module yard (Nisku)
- Eliminates field rework & enhances safety
- Shared services model increases purchasing efficiency



## Construction

- Phased approach results in safe, efficient installation
- Assembly line drilling & completions
- Multiple small contractors & long-term relationships

# Committed to maintaining low capital cost structure

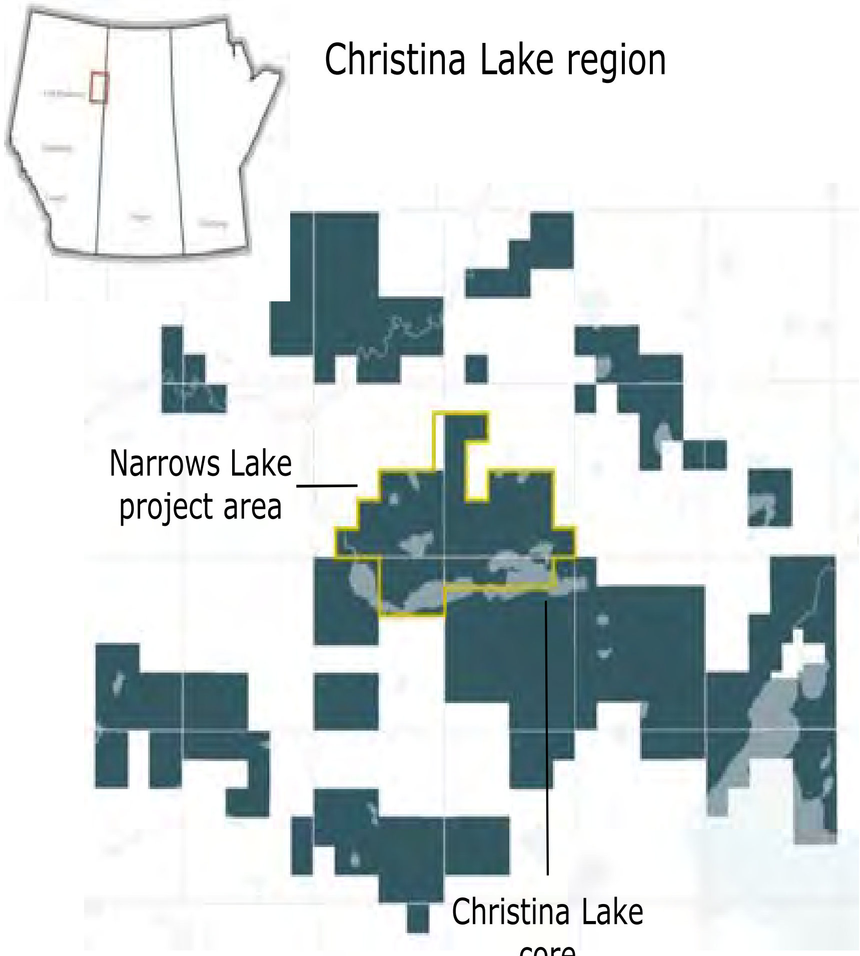
| | |
|---|---|
| $2 - $3/bbl | **Growth capital:**<br>• Phase expansion (includes all infrastructure & initial wells)<br>• Phase debottlenecking & optimization<br>• Numerator for capital efficiency calculation |
| $9 - $11/bbl | **Sustaining capital:**<br>• All wells, pads, pipelines beyond initial capacity<br>• Operating capital<br>• Maintenance capital<br>• Stratigraphic wells & seismic<br>• Environment, health & safety initiatives<br>• Technology development |

Target total capital ~$11 - $14/bbl full cycle

# Progressing engineering at Narrows Lake

## Narrows Lake commercial project:

- First commercial SAGD project to incorporate solvent aided process (SAP)
- Evaluating development options to leverage existing infrastructure at nearby Christina Lake project
- Expected initial production capacity 45,000 bbls/d (phase A)
- Expected ultimate production capacity 130,000 bbls/d

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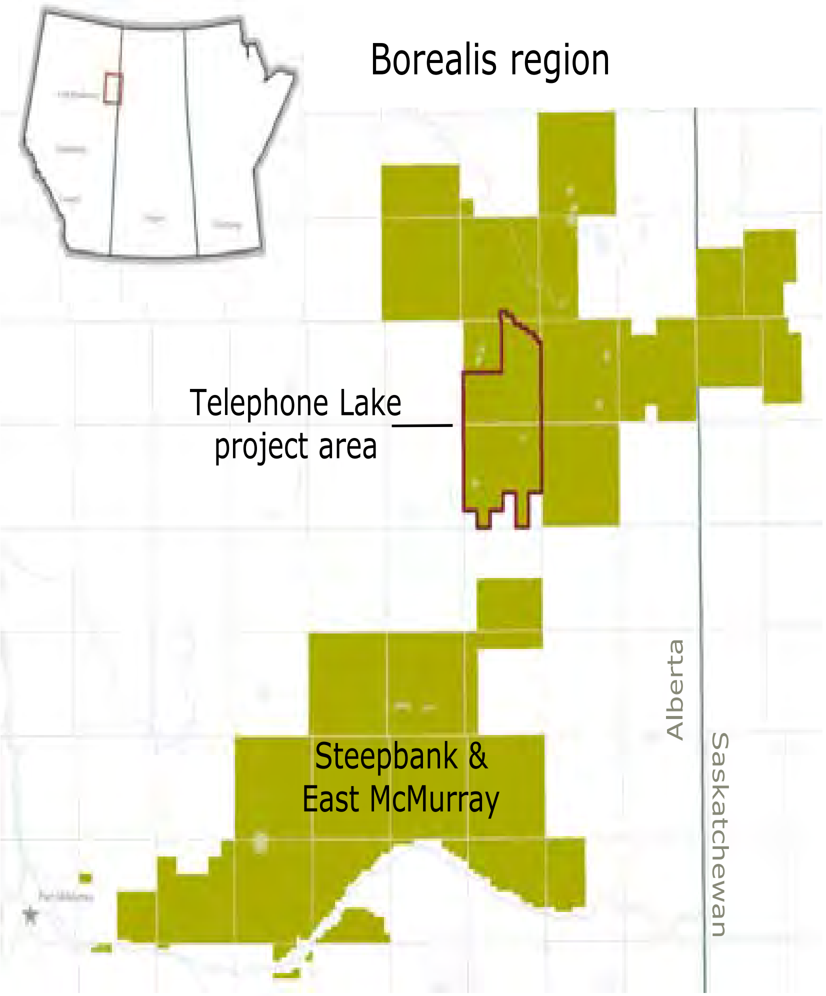
# Assessing development options at Telephone Lake

**Telephone Lake commercial project:**

- Regulatory approval received in 2014
- Continuing engineering work; assessing development options
- Project SOR – 2.1
- Expected initial production capacity 90,000 bbls/d (phases A & B)
- Expected ultimate production capacity 300,000+ bbls/d

**Borealis region:**

- Contingent resources* – 5.7 Bbbls




Contingent resources are best estimates, shown before royalties and on a net basis at December 31, 2014. *Borealis region includes Telephone Lake, Steepbank & East McMurray and East Borealis.

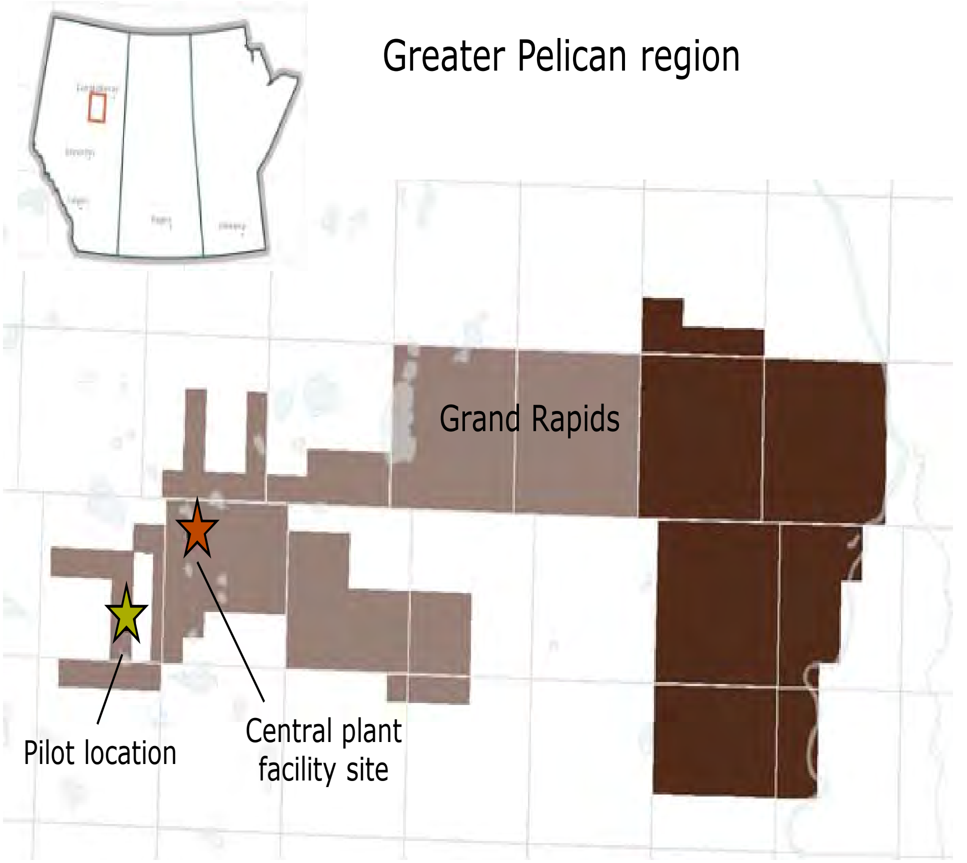
# Continuing to evaluate Grand Rapids

**SAGD pilot update:**

- Operating since 2010
- Two well pairs currently producing
- Third pilot well pair completed Q1 2015; steam circulation expected to start Q2 2015

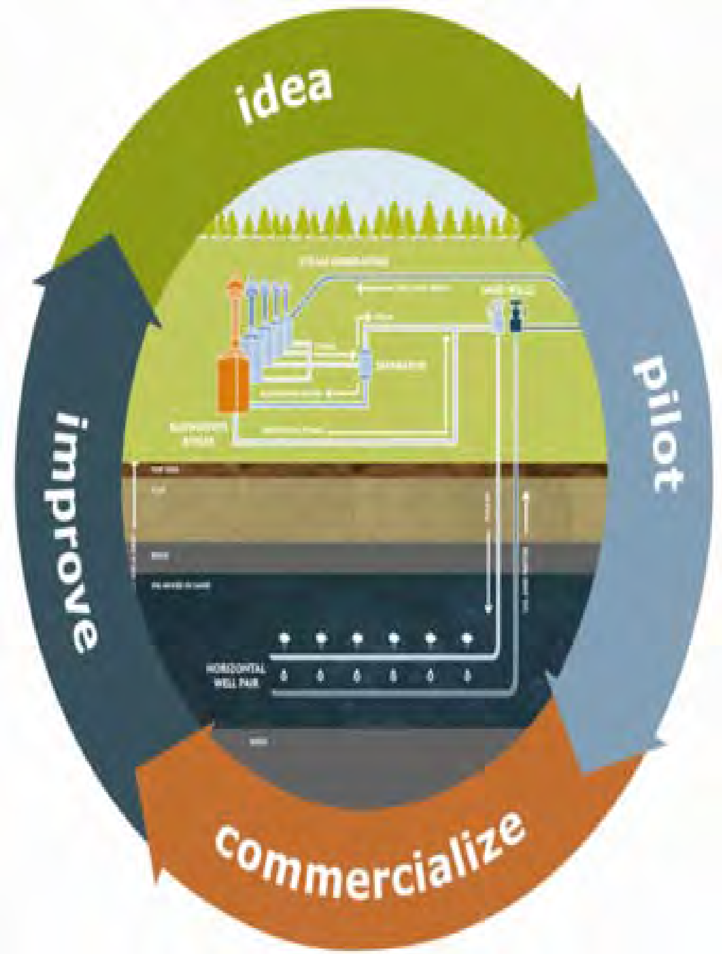
**Commercial project:**

- Received regulatory approval Q1 2014
- Expected total production capacity of 180,000 bbls/d
- Project SOR 3.0 – 3.5
- Contingent resources – 1.7 Bbbls
- Phase A: 8,000 – 10,000 bbls/d
  - moved acquired facility to Cenovus yard for storage




Contingent resources are bitumen best estimates, shown before royalties and on a net basis at December 31, 2014. See advisory for definitions.

# Driving innovation in oil sands through technology



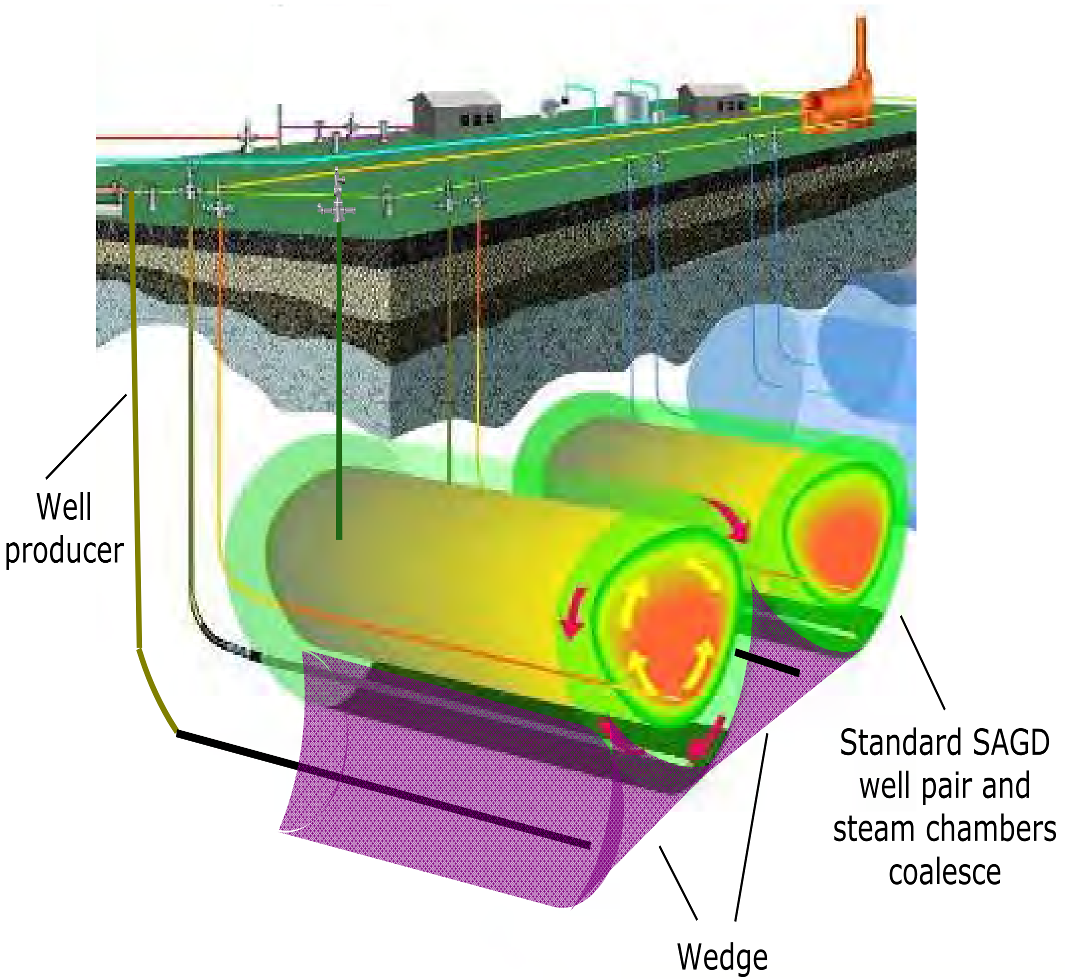

**Technology development drives SAGD performance:**

- Wedge Well™ technology
- Blowdown boiler
- Electric submersible pumps
- SkyStrat™ drilling rig
- Solvent aided process
- Dewatering process

# Wedge Well™ technology optimizes reservoir performance

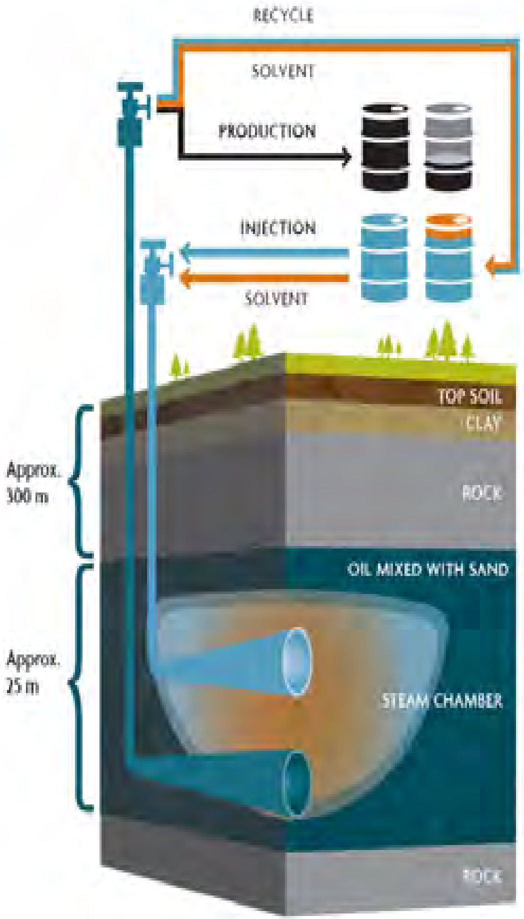
**Technology details:**

- < 0.1 average SOR
- Acceleration of production
- 10 – 15% relative increase in recovery factor
- Foster Creek wells – 89 currently producing
- Christina Lake wells – 25 currently producing



# SAP at Narrows Lake improves project economics

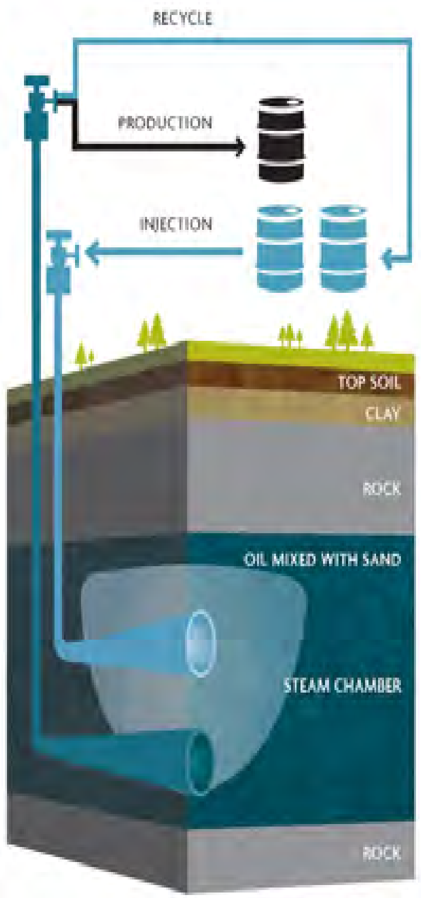
### SAP




### SAP vs. SAGD:

- Decreases SOR by ~30%
- Increases full field recovery rates by ~15%
- Increases growth capital 10 - 20%
- Decreases sustaining capital by ~10%
- Reduces non-fuel operating costs by 5 - 10%
- Lowers emissions, water usage & land footprint

### SAGD



# SkyStrat™ drilling rig technology accelerates SAGD development

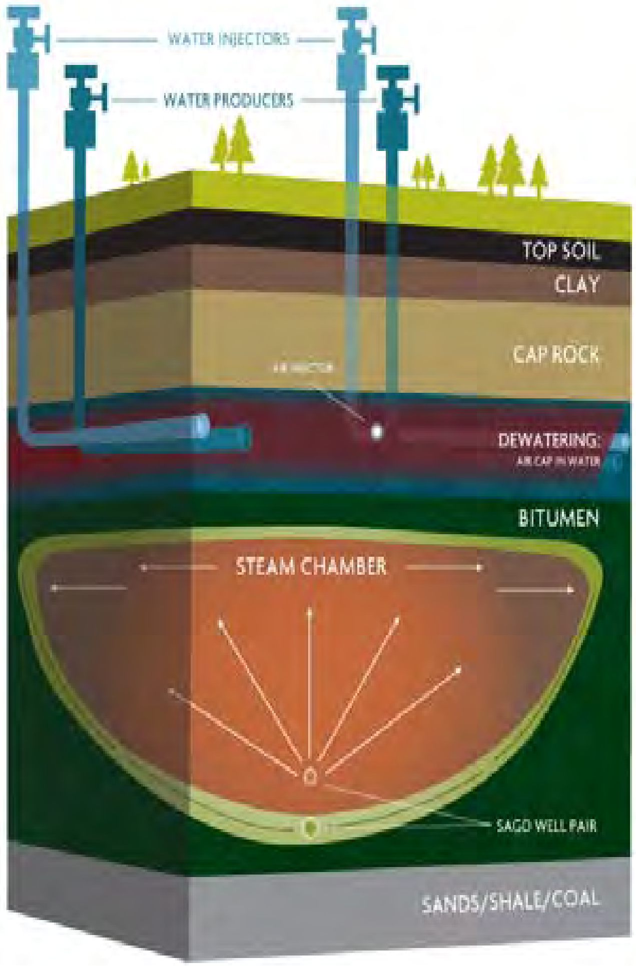
| Traditional strat well | SkyStrat™ drilling rig |
|---|---|
| 90 day window | Year-round drilling |
| High access costs | Lower access costs |
| Short season leads to labour inefficiencies | Year-round drilling ensures access to top crews |
| Access roads impact environment | Helicopter lowers environmental impact |

**SkyStrat™ drilling rig technology lowers costs up to 25%**

# Telephone Lake dewatering pilot successful

## Dewatering pilot update:

- Purpose was to reduce SOR
- Worked as expected
- 4D seismic & well logs indicate we successfully replaced water & confined air
- ~70% of mobile top water was displaced in the pilot area
- Pilot completed in Q4 2013



# Conventional oil & natural gas

Our conventional operations include crude oil and natural gas assets in Alberta and Saskatchewan, including a $CO_2$ enhanced oil recovery project in Weyburn, heavy oil development at Pelican Lake and tight oil assets in Alberta.

*Shown here are two oil wells near Drumheller, Alberta.*

# Conventional assets and non-core dispositions help fund oil sands growth

## Conventional oil & gas:

- ~70% fee lands
- Payback less than three years
- Scalable & flexible capital program
- Diversification of product streams
- Provides economic hedge for oil sands fuel gas consumption

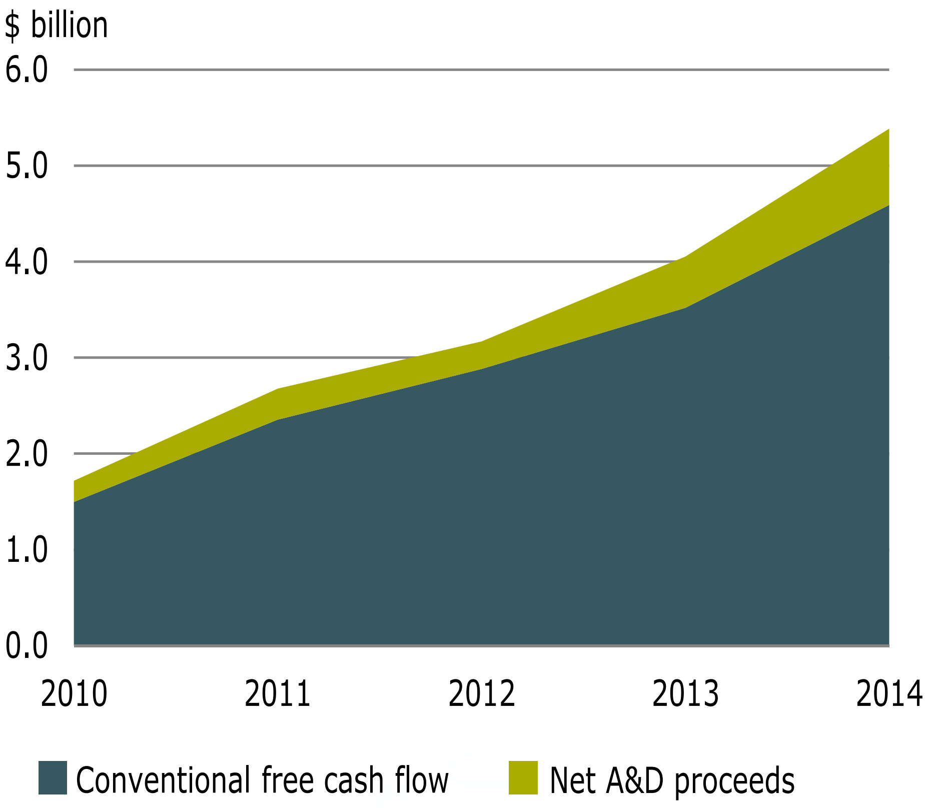
## Pelican Lake:

- Water/polymer flood

## Weyburn:

- $CO_2$ sequestration/waterflood

## Cumulative free cash flow




Free cash flow is a non-GAAP measure. See advisory.

# Fee lands provide strategic opportunity

### Fee lands generate free cash flow:

- 3.1 MM net acres (~90% fee)
- Mineral rights owned in perpetuity
- No royalties payable to the Crown
- 2014 royalty interest volumes of ~7,600 BOE/d (~55% liquids)
- 2014 operating cash flow of $150 million

### Market ready:

- To pursue various potential options with respect to our fee lands when the right opportunity presents itself


Free cash flow and operating cash flow are non-GAAP measures. See advisory. Cenovus fee land at December 31, 2014.

# Refining, marketing & transportation

We continue to benefit from our overall integrated approach, including interests in two U.S. refineries.

*The Wood River Refinery, shown here, is strategically located in the mid-continent with access to heavy crude.*

# Expanding margin through market access & integration

**Participating in the value chain to expand margin**

## Production

Alberta pricing

## Transportation

North American & global crude pricing

## Refining

Global product pricing

# Integration continues to deliver value & reduce cash flow volatility

- Refineries have access to discounted crudes
  - Wood River accesses multiple pipelines – Keystone, Express-Platte, Mustang, Ozark
  - Borger has access to Canadian heavy, West Texas Sour & growing Permian supply
- Debottlenecking at Wood River could increase heavy oil processing capacity by up to 10%
  - received partnership sanctioning for debottlenecking project Q1 2014; start-up expected 2016

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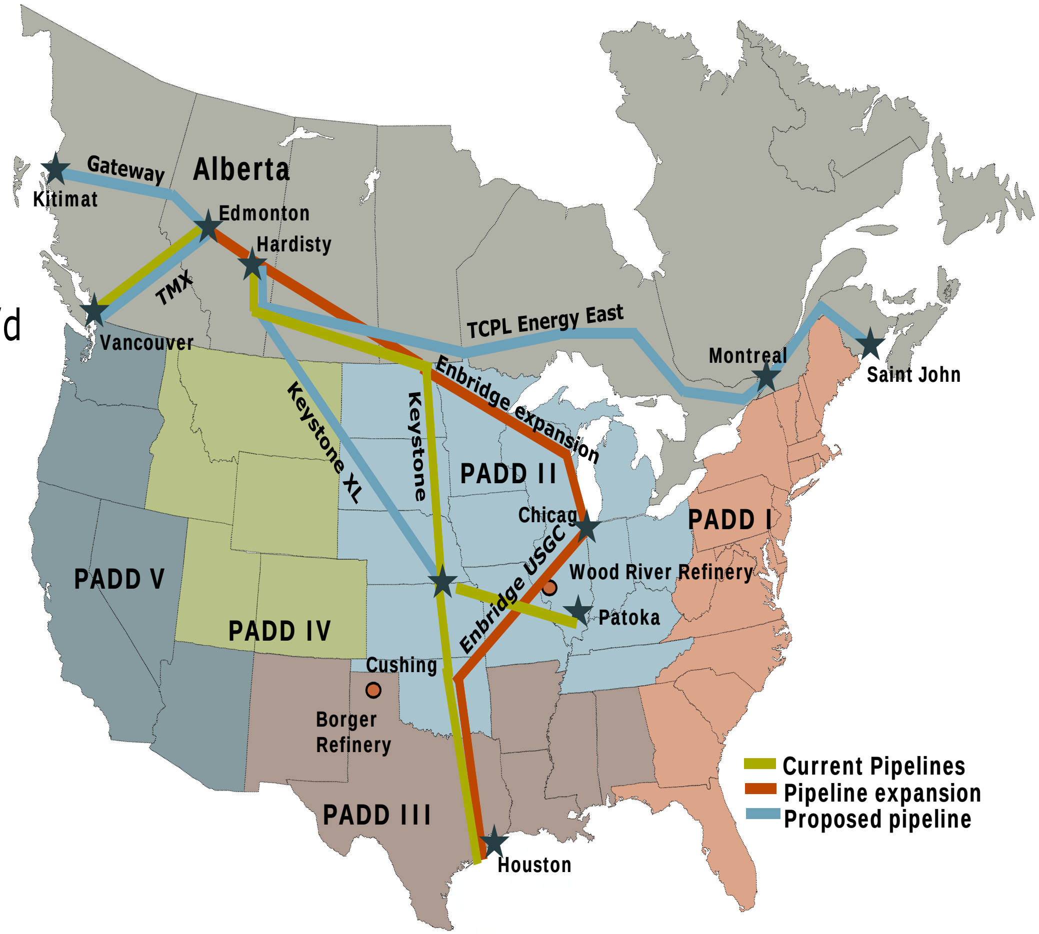
# Committing to pipeline expansions for market access

## Current pipeline access:

- West Coast:
  Trans Mountain – 11,500 bbls/d
- US Gulf Coast:
  Enbridge USGC/Flanagan South – 75,000 bbls/d

## Adding pipeline commitments:

- US Gulf Coast:
  TCPL Keystone XL – 75,000 bbls/d
- East Coast:
  TCPL Energy East to Saint John, NB
  200,000 bbls/d
- West Coast:
  Trans Mountain & Northern Gateway up to
  175,000 bbls/d

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# Rail transportation plans

- Long-term plan to ship 10-20% of corporate volumes by rail
- Taken delivery of more than half of the 825 coiled & insulated rail cars ordered as of Q1 2015
- Secured 30,000 bbls/d gross loading capacity between:
  - USDG/Gibsons terminal (Hardisty)
  - Canexus Bruderheim terminal (Edmonton)

# Financial

Our financial strategy continues to support the business plan. We're focused on total shareholder return and building long-term value.

*This photo was taken at Suffield, one of the core areas of our crude oil and natural gas production in Alberta.*

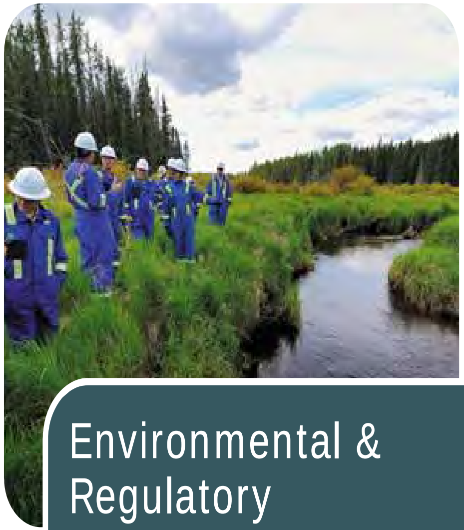
# Managing risk through a balanced approach

## Operational

- Heavy oil production integrated with refining capacity
- Scalable conventional oil programs provide flexibility
- Portfolio approach to transportation

## Financial

- Financial strength to support growth plans
- Natural gas is a financial asset & provides a natural hedge
- Hedging protects capital programs
- Ongoing portfolio management



## Environmental & Regulatory

- Integrating environment into business planning
- Taking strategic actions to improve performance
- Proactive oil sands application process

# Maintaining financial strength & flexibility to support the business plan

- Ensure significant liquidity & long-term debt maturities
  - $3.0 billion committed credit facility maturing November 30, 2019
  - $1.0 billion committed credit facility maturing November 30, 2017
  - US$4.75 billion in notes with no maturities until 2019
    - weighted average interest rate – 5.3%
- Strong balance sheet
  - debt to capitalization 35%, debt to adjusted EBITDA 1.9x
  - net debt to capitalization 27%, net debt to adjusted EBITDA 1.3x
- Integrated business model
  - refining capacity
  - natural gas production

Debt and net debt ratios are non-GAAP measures. See advisory.

# Mitigating commodity price risk

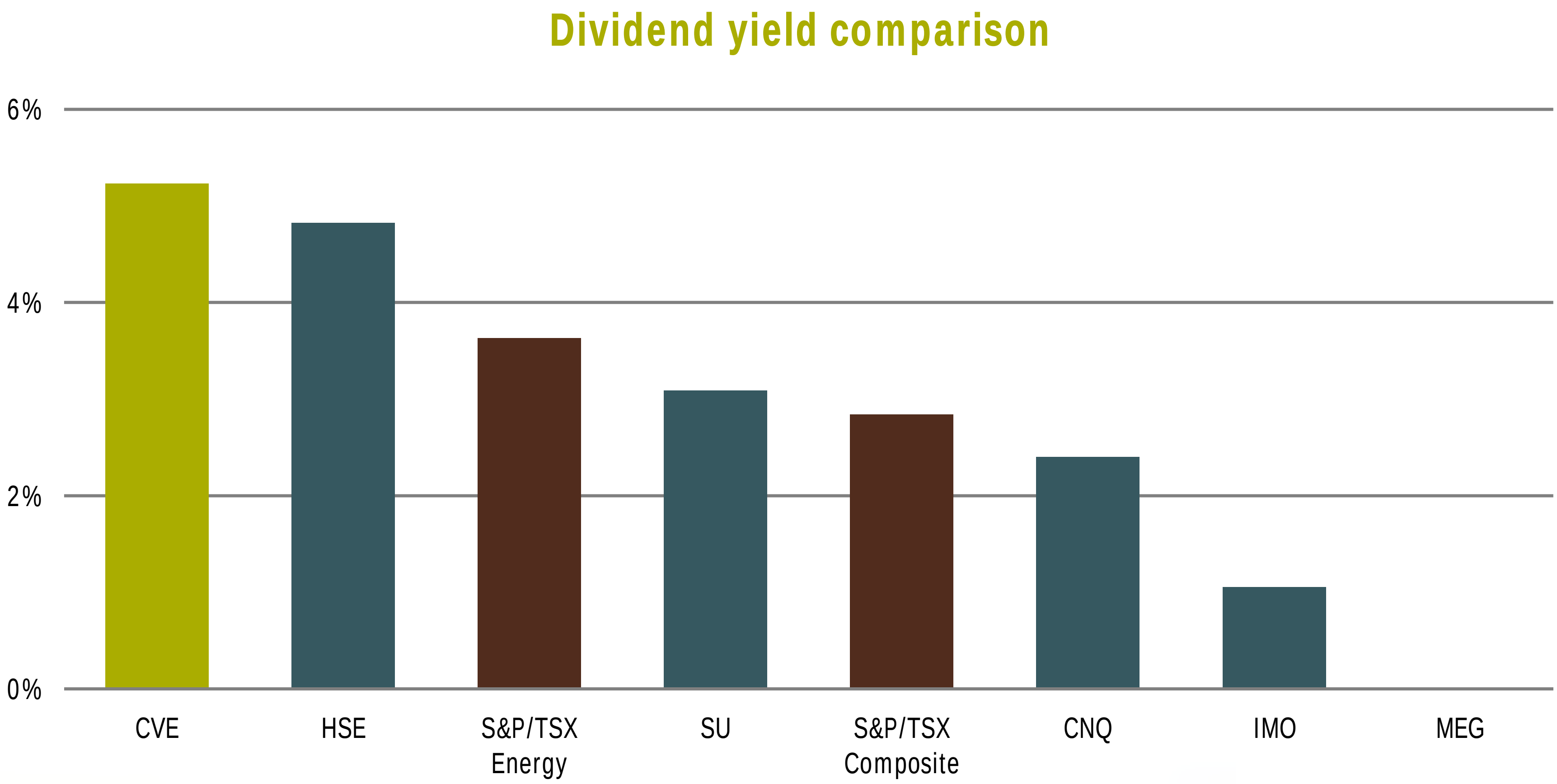
| Hedges at March 31, 2015 | Volume hedged | Hedge price | Production 2015F | Volume % hedged |
|---|---|---|---|---|
| Crude – Brent Fixed Price, 2015 | | | 204 Mbbls/d | 25% |
| January – June | 1,000 bbls/d | $100.25/bbl | | |
| January – December | 18,000 bbls/d | $113.75/bbl | | |
| January – June | 6,000 bbls/d | US$65.03/bbl | | |
| March – June | 45,000 bbls/d | US$56.45/bbl | | |
| July - September | 18,000 bbls/d | US$60.03/bbl | | |
| October – December | 1,000 bbls/d | US$64.00/bbl | | |
| Crude – Brent Collars, 2015<br>January – December | 10,000 bbls/d | $105.25 – $123.57/bbl | | |
| Crude – Brent Fixed Price, 2016<br>January – December | 4,000 bbls/d | US$65.75/bbl | | |

| Differential hedges at March 31, 2015 | Volume hedged | $/bbl discount |
|---|---|---|
| WTI-WCS Differential<br>January– June | 4,900 bbls/d | US$19.85 |

| Hedges at March 31, 2015 | Volume hedged | Hedge price | Production 2015F | Volume % hedged |
|---|---|---|---|---|
| AECO – Fixed Price<br>January – December | 149 MMcf/d | $3.86/Mcf | 438 MMcf/d | 34% |
| Internal use & long-term fixed price sale [1] | 209 MMcf/d | | | 48% |

[1] Internal use 180 MMcf, long- term fixed price sale 29 MMcf.
2015F production based on January 28, 2015 guidance.

# Strong dividend yield




Annualized Q2 2015 dividend and share price as at May 13, 2015 for CVE and peers. Source: Bloomberg and CVE.

# Creating value through social & governance performance

**Committed to good governance**

- SER Committee of the Board provides oversight of environment and sustainability performance
- Enterprise Risk Management program, practices and policy ensure active and effective risk mitigation
- Transparent disclosure and reporting through annual Corporate Responsibility Report and CDP GHG and Water Disclosure Projects

**Building long-term support in our communities**

- Partnering with Aboriginal communities through employment, education, and business development

  ➔ **more than $1 billion spent since 2009 on goods and services supplied by Aboriginal businesses**

- Participating as an Imagine Canada Company - >1% of pre-tax profits donated to non-profit organizations to create shared value and build long-term relationships in the communities where we operate

  ➔ **more than $68 million donated through our community investment program since 2009**

**Euronext Vigeo World 120 Index** for Responsible Performance

**DJSI World Index** and **North American Index**

**IR Magazine** Best Sustainability Practice

**Carbon Disclosure Leadership Index Canada**

**Corporate Knights Global 100** List and Best 50 Corporate Citizens in Canada

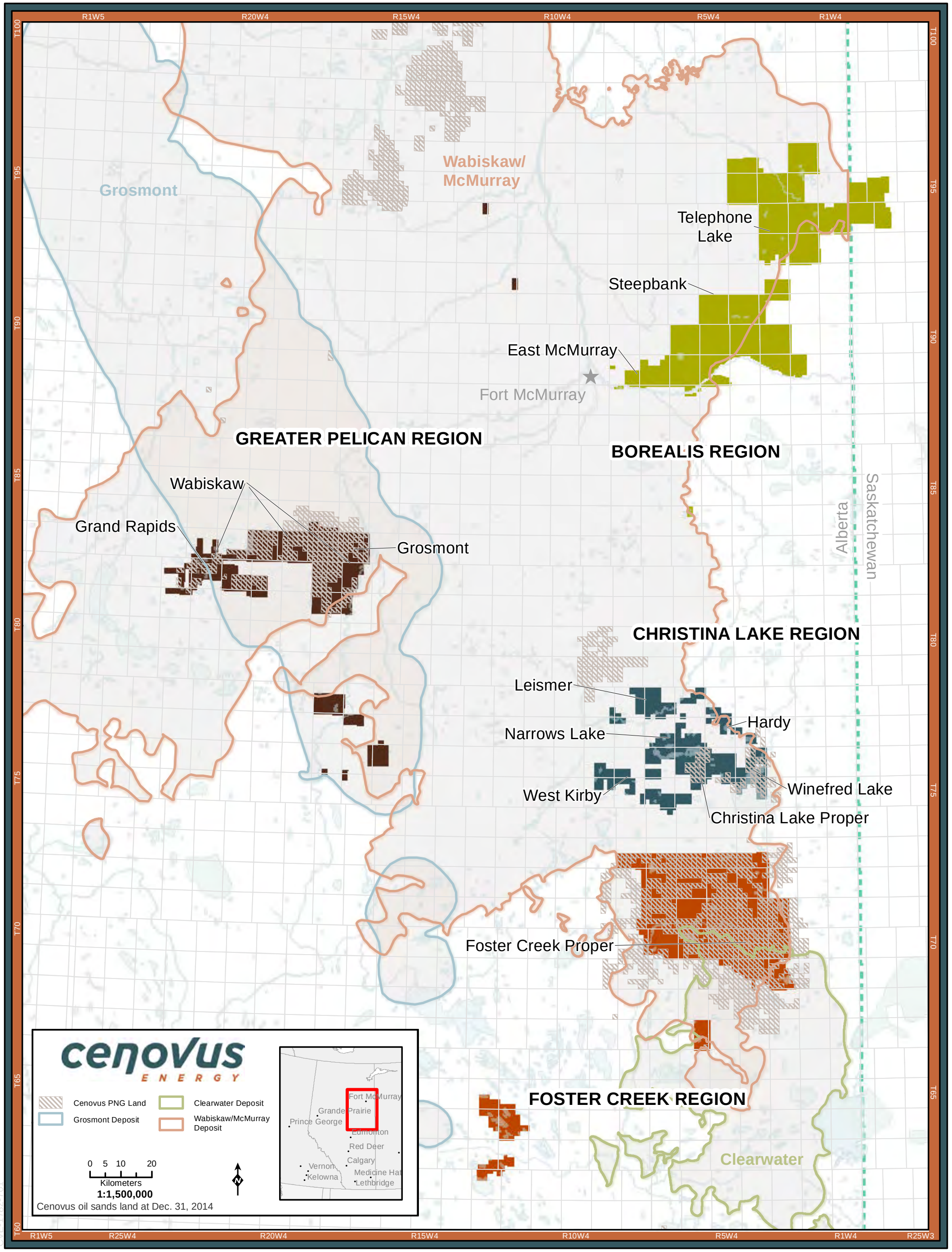
# Advancing our environmental performance

- Rigorous regulatory framework ensures environment considerations throughout project lifecycle
- Dedicated internal environment team focused on mitigating environmental risks
- Ongoing technology investment and collaboration through COSIA advances Cenovus and industry environmental performance
- Low carbon intensity, carbon price modelling, and innovation drive leadership in oil sands carbon emissions performance
  - life-cycle carbon emissions on par with average crude oil consumed in North America

| CVE a top performer for key indicators | |
|---|---|
| Indicator | CVE vs industry average |
| Direct GHG emissions intensity<br>Oil sands | - 43% |
| Fresh water intensity<br>Oil sands | -23% |
| $NO_x$ intensity<br>Cenovus wide | -51% |
| $SO_2$ intensity<br>Cenovus wide | -84% |

Source: 2013 CAPP Responsible Canadian Energy Report (capp.ca) April 2014. Industry values reflect data from 2012.
Negative value reflects Cenovus performance lower than industry average.

cenovus ENERGY



Wabiskaw/ McMurray
Grosmont
Telephone Lake
Steepbank
East McMurray
Fort McMurray
GREATER PELICAN REGION
BOREALIS REGION
Wabiskaw
Grand Rapids
Grosmont
Alberta
Saskatchewan
CHRISTINA LAKE REGION
Leismer
Hardy
Narrows Lake
West Kirby
Winefred Lake
Christina Lake Proper
Foster Creek Proper
FOSTER CREEK REGION
Clearwater
cenovus ENERGY
Cenovus PNG Land
Grosmont Deposit
Clearwater Deposit
Wabiskaw/McMurray Deposit
0 5 10 20
Kilometers
1:1,500,000
Cenovus oil sands land at Dec. 31, 2014
Fort McMurray
Grande Prairie
Prince George
Edmonton
Red Deer
Calgary
Vernon
Kelowna
Medicine Hat
Lethbridge

# Advisory

**FORWARD-LOOKING INFORMATION** This presentation contains certain forward-looking statements and other information (collectively "forward-looking information") about our 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 "anticipate", "expect", "plan", "forecast" or "F", "target", "project", "capacity", "could", "should", "focus", "proposed", "goal", "outlook", "potential", "may", "projected" or similar expressions and includes suggestions of future outcomes, including statements about our strategy and related milestones and schedules, projected future value, projections contained in our 2015 guidance, forecast operating and financial results, planned capital expenditures, including the timing and financing thereof, expected future production, including the timing, stability or growth thereof, expected future refining capacity, broadening market access, improving cost structures, anticipated finding and development costs, expected reserves, contingent, prospective and bitumen and petroleum initially-in-place resources estimates, bitumen recovery estimation, dividend plans and strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including to reduce our environmental impact and projected shareholder return and long-term value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: assumptions disclosed in our current guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities. The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; 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; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation, including sufficient crude-by-rail or alternate transportation; 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 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 the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the 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.

2015 guidance, updated January 28, 2015 and available at cenovus.com, is based on an average diluted number of shares outstanding of approximately 760 million. It assumes: Brent US$53.50/bbl, WTI of US$50.50/bbl; WCS of US$36.25/bbl; NYMEX of US$3.00/MMBtu; AECO of $2.70/GJ; Chicago 3-2-1 crack spread of US$11.75/bbl; exchange rate of $0.83 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; 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 and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; 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; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation, including sufficient crude-by-rail or other alternate transportation; 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 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 the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the 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.

The forward-looking information contained in the presentation, and the foregoing lists (which are not exhaustive), are made as of the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our most recent Annual Information Form (AIF)/Form 40-F, "Risk Management" in our current and annual Management's Discussion and Analysis (MD&A) and risk factors described in other documents we file from time to time with securities regulatory authorities, all of which are available on SEDAR at sedar.com, EDGAR at www.sec.gov.

**OIL & GAS INFORMATION** The estimates of reserves and contingent resources were prepared effective December 31, 2014 and the estimates of bitumen initially-in-place were prepared effective December 31, 2012. All estimates were prepared by independent qualified reserves evaluators, based on definitions contained in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101. Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2014, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of those resources. Actual resources may be greater than or less than the estimates provided.

Total bitumen initially-in-place (BIIP) estimates, and all subcategories thereof, including the definitions associated with the categories and estimates, are disclosed and discussed in our July 24, 2013 news release, available on SEDAR at sedar.com and at cenovus.com. BIIP estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. Cumulative production, reserves and contingent resources are disclosed on a before royalties basis. All estimates are best estimate, billion barrels (Bbbls). *Total BIIP* (143 Bbbls); *discovered BIIP* (93 Bbbls); *commercial discovered BIIP* equals the *cumulative production* (0.1 Bbbls) plus *reserves* (2.4 Bbbls); *sub-commercial discovered BIIP* equals *economic contingent resources* (9.6 Bbbls) plus the *unrecoverable portion of discovered BIIP* (81 Bbbls); *undiscovered BIIP* (50 Bbbls); *prospective resources* (8.5 Bbbls); *unrecoverable portion of undiscovered BIIP* (42 Bbbls). Any contingent resources as at December 31, 2012 that are sub-economic or that are classified as being subject to technology under development have been grouped into the unrecoverable portion of discovered BIIP. Petroleum initially-in-place (PIIP) estimates for Pelican Lake are effective December 31, 2012 and were prepared by McDaniel. All estimates are best estimate discovered PIIP volumes as follows: *Mobile Wabiskaw* total PIIP (2.11 Bbbls); discovered PIIP (2.11 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0.03 Bbbls); unrecoverable discovered PIIP (1.72 Bbbls); undiscovered PIIP (0 Bbbls). *Mobile Wabiskaw development area* total PIIP (1.62 Bbbls); discovered PIIP (1.62 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.26 Bbbls); undiscovered PIIP (0 Bbbls). *Immobile Wabiskaw* total PIIP (1.33 Bbbls); discovered PIIP (1.33 Bbbls); cumulative production (0 Bbbls); reserves (0 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.33 Bbbls); undiscovered PIIP (0 Bbbls).

Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

**NON-GAAP MEASURES** Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as, Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Readers are encouraged to review our most recent Management's Discussion and Analysis, available at cenovus.com for a full discussion of the use of each measure.

# Corporate guidance

## 2015 Corporate Guidance - C$, before royalties

January 28, 2015

### UPSTREAM

#### OIL SANDS

| | Production (Mbbls/d) | Capital expenditures ($ millions) | | Operating costs ($/bbl) | Effective royalty rates (%) | Steam to oil ratio |
|---|---|---|---|---|---|---|
| Foster Creek | 62 - 68 | 550 - 600 | *Fuel* | 2.75 - 3.25 | 1 - 2 | 2.6 - 3.0 |
| | | | *Non-fuel* | 12.00 - 14.00 | | |
| | | | *Total* | 14.75 - 17.25 | | |
| Christina Lake | 67 - 74 | 650 - 700 | *Fuel* | 2.50 - 3.00 | 1 - 2 | 1.8 - 2.1 |
| | | | *Non-fuel* | 8.50 - 10.00 | | |
| | | | *Total* | 11.00 - 13.00 | | |
| Narrows Lake | - - | 30 - 40 | | - - | - - | - - |
| New resource plays [1] | - - | 90 - 100 | | - - | - - | - - |
| Oil Sands total | 129 - 142 | 1,320 1,440 | | | | |

#### CONVENTIONAL

| | Production | Capital expenditures ($ millions) | Operating costs | Effective royalty rates (%) |
|---|---|---|---|---|
| | (Mbbls/d) | | ($/bbl) | |
| Oil & liquids [2] | 66 - 70 | 200 - 215 | 20.00 - 22.50 | 9 - 11 |
| | (MMcf/d) | | ($/Mcf) | |
| Natural gas [3] | 420 - 455 | 25 - 30 | 1.30 - 1.45 | 1 - 2 |

#### TOTAL

| | Production (Mbbls/d, MBOE/d) | Capital expenditures ($ millions) |
|---|---|---|
| Total liquids | 195 - 212 | 1,520 - 1,655 |
| Total upstream | 265 - 288 | 1,545 - 1,685 |

### REFINING

| | Capital expenditures ($ millions) | Operating costs ($/bbl) |
|---|---|---|
| Refining [4] | 240 - 260 | 8.00 - 9.00 |

### CORPORATE

| | | | |
|---|---|---|---|
| Total cash flow ($ billions) [5] | 1.3 - 1.5 | Upstream DD&A ($ billions) | 1.5 - 1.7 |
| - per common share, diluted ($/share) | 1.70 - 2.00 | Other DD&A ($ millions) [6] | 255 - 290 |
| Total capital expenditures ($ billions) | 1.8 - 2.0 | Cash tax ($ millions) | 0 - 50 |
| General & administrative expenses ($ millions) | 390 - 445 | Effective tax rate (%) [7] | 27 - 32 |

### PRICE ASSUMPTIONS & CASH FLOW SENSITIVITIES [8]

| | | **Independent base case sensitivities** | Increase ($ millions) | Decrease ($ millions) |
|---|---|---|---|---|
| Brent (US$/bbl) | $53.50 | | | |
| WTI (US$/bbl) | $50.50 | | | |
| Western Canada Select (US$/bbl) | $36.25 | Crude oil (WTI) - US$10.00 change | 580 | (650) |
| NYMEX (US$/MMBtu) | $3.00 | Light-heavy differential (WTI-WCS) - US$5.00 change | (260) | 175 |
| AECO ($/GJ) | $2.70 | Chicago 3-2-1 crack spread - US$1.00 change | 90 | (95) |
| Chicago 3-2-1 Crack Spread (US$/bbl) | $11.75 | Natural gas (NYMEX) - US$1.00 change | 51 | (60) |
| Exchange Rate (US$/C$) | $0.83 | Exchange rate (US$/C$) - $0.05 change | (130) | 130 |

(1) New resource plays includes Grand Rapids, Telephone Lake, and other emerging plays.
(2) Oil & liquids includes Pelican Lake as well as oil and NGLs from Alberta and Saskatchewan.
(3) Natural gas includes all natural gas production.
(4) Refining capital and operating costs are reported in C$, but incurred in US$ and as such will be impacted by FX.
(5) This is a non-GAAP measure as described in the Advisory.
(6) Includes DD&A related to Refining and Corporate and Eliminations.
(7) Statutory rates of 25% in Canada and 38% in the US are applied separately to pre-tax earnings streams for each country. Excludes the effect of mark-to-market gains and losses.
(8) Sensitivities include hedge positions as at December 31, 2014 and are applicable to 2015. Refining results embedded in the sensitivities are based on unlagged margin changes and do not include the effect of changes in inventory valuation for first-in, first-out/lower of cost or net realizable value.

# Advisory

**NON-GAAP MEASURES.** This document contains references "cash flow", which is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows in our interim and annual Consolidated Financial Statements, available at cenovus.com.

**FORWARD-LOOKING INFORMATION.** This document provides guidance on certain aspects of our business and includes forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends and based on the assumptions and uncertainties discussed below. Although we believe that our guidance and the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct and readers are cautioned that the information presented may not be appropriate for any other purpose. Forward-looking information in this document includes: estimates of production volumes; estimates of total cash flow, including per common share, and operating costs; projected capital expenditures; estimates of general and administrative expenses; estimates of US$/C$ exchange rates, depreciation, depletion and amortization (DD&A); cash tax, effective tax rates, royalty rates and price assumptions; steam to oil ratio; and projected sensitivities and impact on cash flow. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

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