Investor Day
June 1, 2016

Husky Energy

Agenda

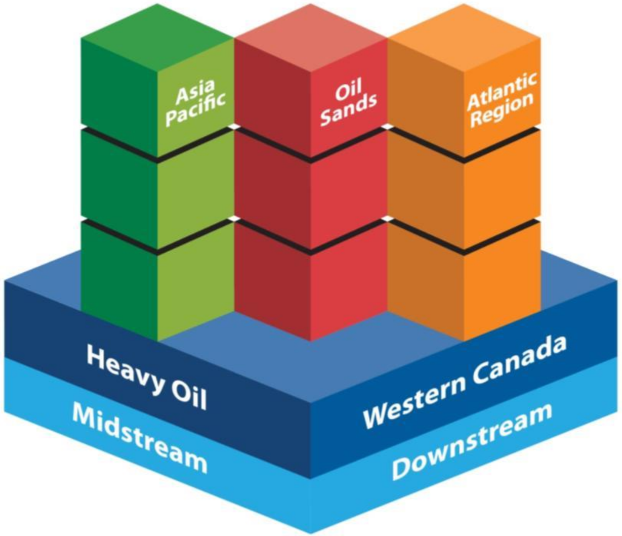
Strategic Update		
9:00	Strategy Update	Asim Ghosh
	Financial Plan	Jon McKenzie
	Portfolio Overview	Rob Peabody
Portfolio Overview		
9:30	Introduction	Rob Peabody
	Oil Sands	John Myer
	Heavy Oil	Ed Connolly
	Downstream	Bob Baird
	Segment Q & A	
Break		
Portfolio Overview		
10.20	Introduction	Rob Peabody
	Western Canada	Rob Symonds
	Asia Pacific Region	Kevin Moore
	Atlantic Region	Malcolm Maclean
	Segment Q & A	
Closing Comments		
11:05	Concluding Remarks	Asim Ghosh
	Q&A	Asim Ghosh, Rob Peabody, Jon McKenzie
Lunch		

Strategy Update

Asim Ghosh

Business Strategy on Course

- Diverse portfolio
- Focused integration
- Transition to a low sustaining capital business



Portfolio Transformation

Oil Sands

Lloyd Heavy Oil Thermals

Downstream

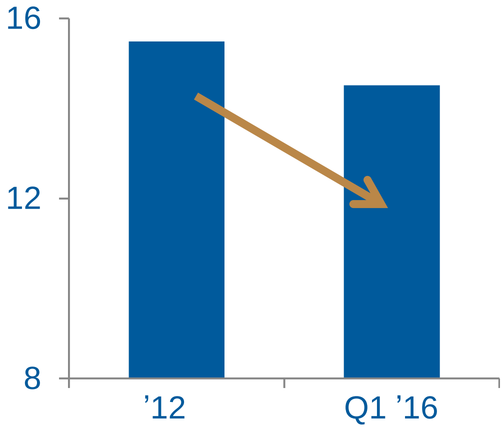
Western Canada

Atlantic Region

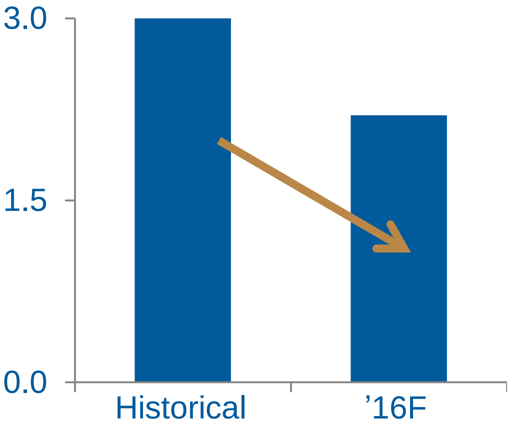
Asia Pacific Region

Pathway to Growing Higher Quality Production

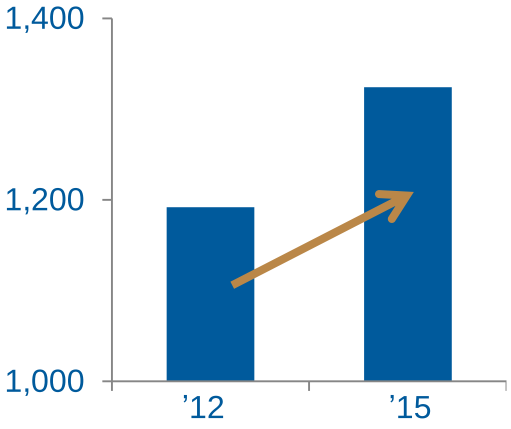
Operating Costs ($/boe)



Total Sustaining and Maintenance Capital ($Bn)

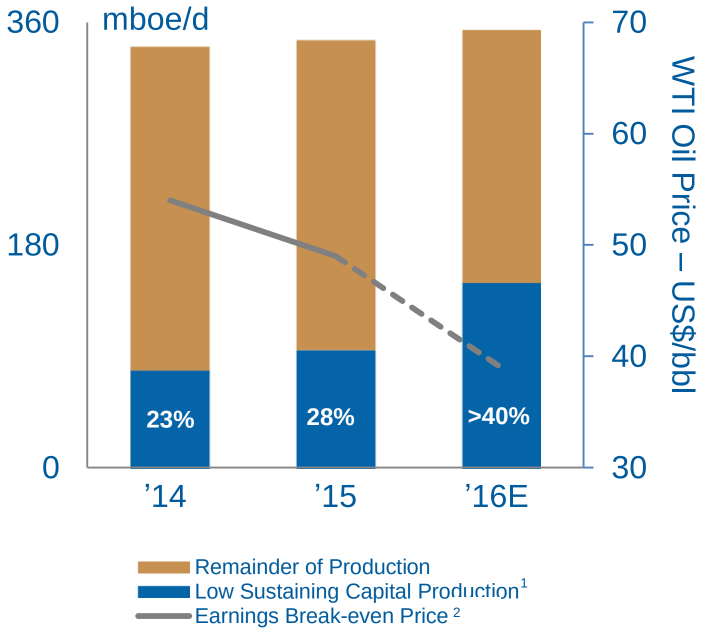


Proved Reserves (mmboe)

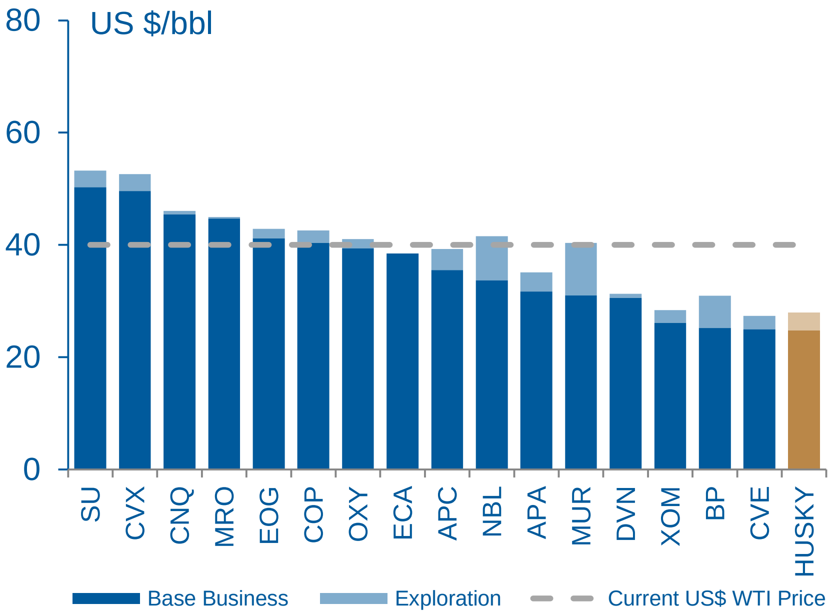


Leading Break-Even Performance

Lower Earnings Break-Even



Cash Flow Break-Even Before Dividends

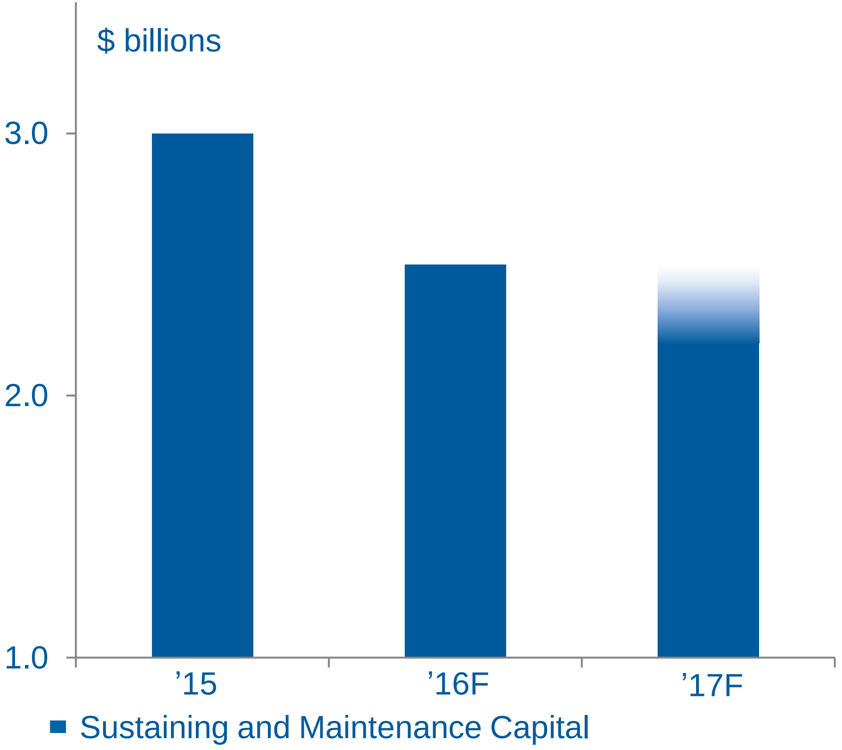


1. Low sustaining capital production, as referred to throughout this presentation, includes production from Tucker, thermals, Sunrise and Asia Pacific natural gas.
2. Earnings Break-even price, as referred to throughout this presentation, has the meaning set out in the Advisories.

Source: *Pre-FID Oil Projects: Global Breakeven Analysis and Cost Curves* (Wood Mackenzie Corporate Service, January 2016.)
Assumptions include exploration, dividends and central costs held flat at Q1 2016 level. Includes Downstream and other businesses.

Doing More With Less

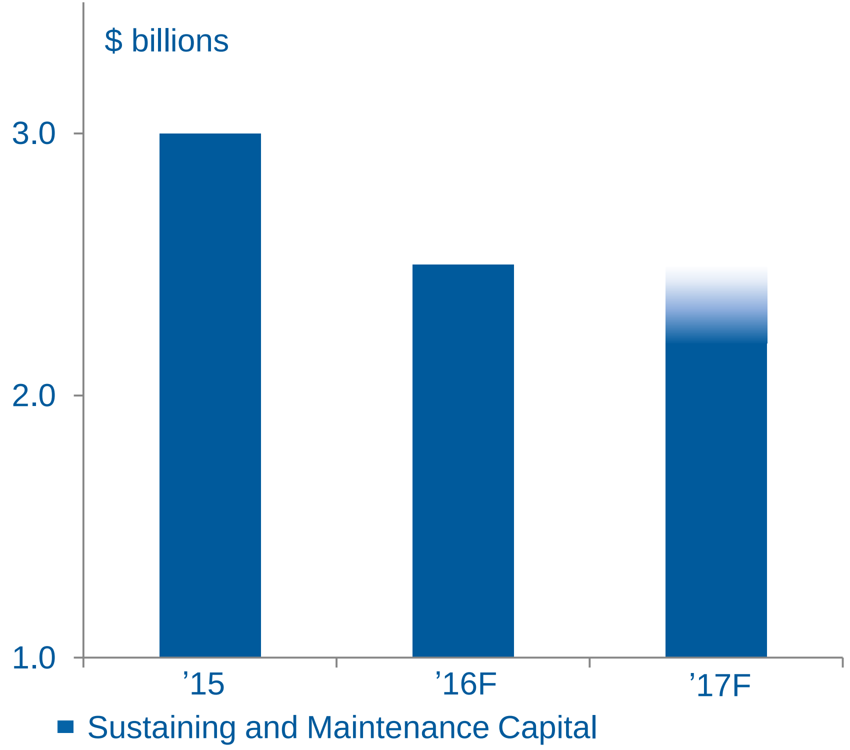
- Sustaining and maintenance capital lowered by 20% from 2015
- Significant opportunities to further lower sustaining costs



Structural Changes Greatly Improving Resiliency . . .

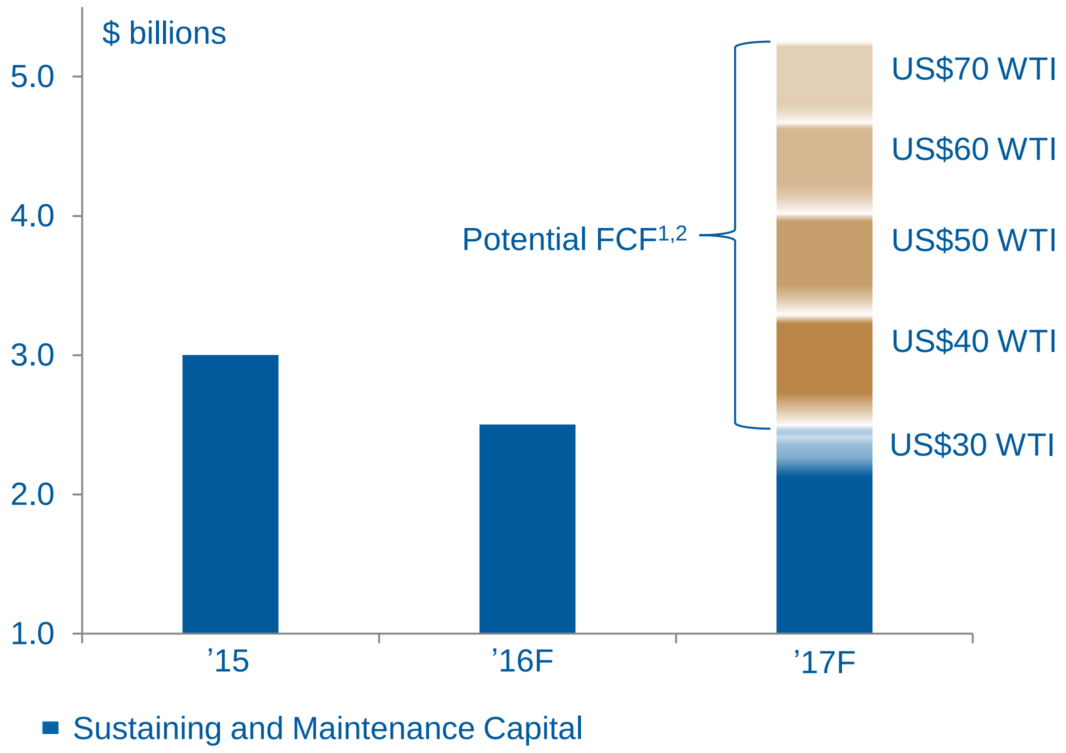
- Capital spending of ~$2.2Bn balanced to cash flow from operations[1] at $30 US WTI price planning assumption
- ~$800 million in cash flow for every $10 increase in WTI

Q1 '16 MD&A Indicative Sensitivity Analysis ($ millions)			
	Increase	Effect on Pre-tax Cash Flow	Effect on Net Earnings
WTI crude oil	US$1.00/bbl	109	80
NYMEX natural gas price[2]	US$0.20/mmbtu	21	15
WTI/Lloyd differential[3]	US$1.00/bbl	(43)	(32)
Light oil margins	Cdn$0.005/litre	11	8
Asphalt margins	Cdn$1.00/bbl	9	6
NY Harbor 3:2:1 Crack Spread	US$1.00/bbl	40	25
FX Rate (US$ per Cdn$)[4]	US$0.01	(33)	(25)



1. Cash flow from operations, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
2. Includes impact of natural gas consumption.
3. Excludes impact on asphalt operations.
4. Does not include gains or losses on inventory and assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.

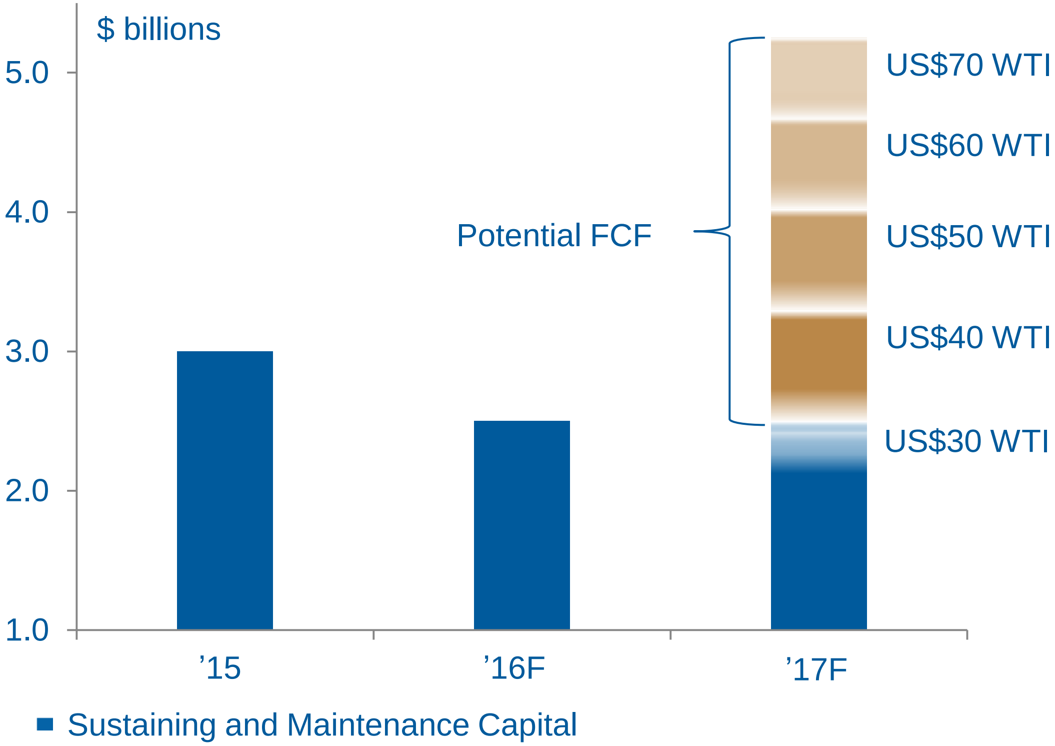
. . . And Generating Free Cash Flow



1. Free cash flow, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
2. Free cash flow growth, as referred to throughout this presentation, is not linear.

Stronger and More Resilient Business

- Business strategy on course
- Structural changes leading to free cash flow
- Strong balance sheet
- Diverse portfolio of high quality growth projects
- Establish a sustainable cash dividend



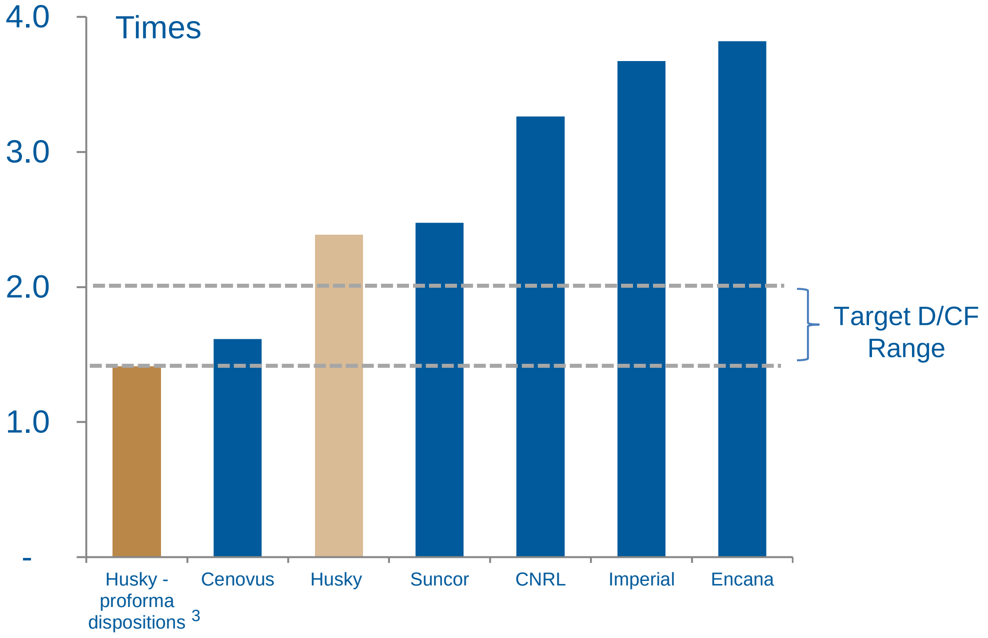
Financial Plan

Jon McKenzie

Sound Financial Plan

- Strong balance sheet
- Enhancing financial flexibility
- Lowering cost structure to enhance free cash flow profile
- Capital efficient investment options

Net Debt to Trailing Cash Flow from Operations[1,2]



1. Net debt to cash flow from operations, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
2. Net debt to trailing cash flow from operations ratio calculated by dividing Net debt by 12-month trailing cash flow from operations as at Mar. 31, 2016.
3. Dispositions and expected gross disposition proceeds, as referred to throughout this presentation, are listed on slide 14.

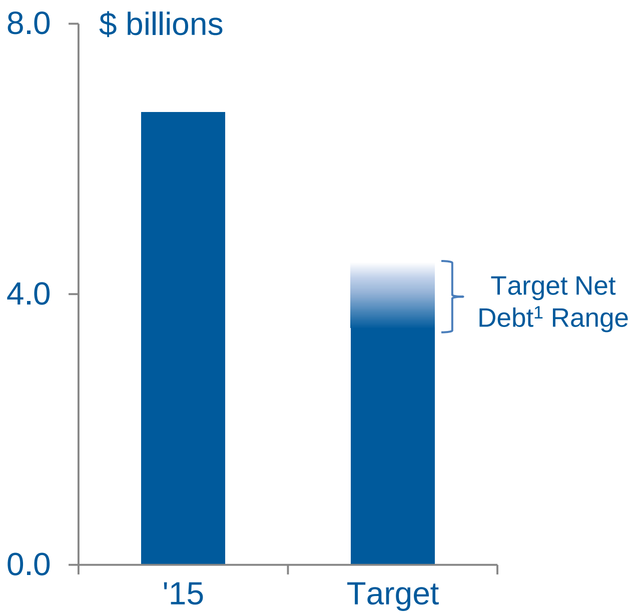
* Peer data sourced from public filings available on SEDAR.

Strengthening the Balance Sheet

- Capex balanced to cash flow from operations
- No new net debt in the near term
- Target of <2x net debt to cash flow from operations

Dispositions	Description	Expected Gross Proceeds
Midstream	Partial sale	$1.7Bn
Royalties	~1,700 boe/d	$163MM
Western Canada	~20,600 boe/d	$900MM
Total	22,300 boe/d	$2.8Bn[2]

Net Debt



1. At $30 US WTI price planning assumption.
2. Signed purchase and sale agreements.

1. Net debt, as referred to throughout this presentation, is calculated as total debt less cash and cash equivalents. Total debt is calculated as long-term debt including long-term debt due within one year and short-term debt.

Enhancing Financial Flexibility

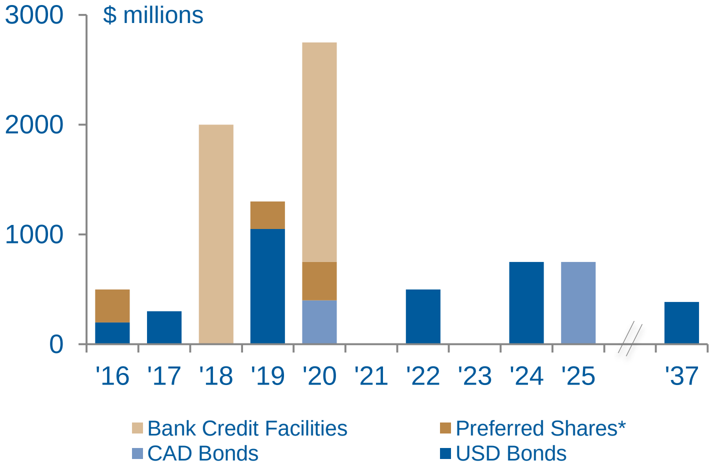
- Maintaining strong investment grade credit rating
  - Ratings confirmed in agency reviews
- Renewed credit facilities
  - Extended maturity date to ’20
- No major long-term bond maturities until ’19

Current Credit Ratings

	Moody's	S&P*	DBRS*
Rating	Baa2	BBB+	A (low)

* Negative outlook

Maturities Schedule

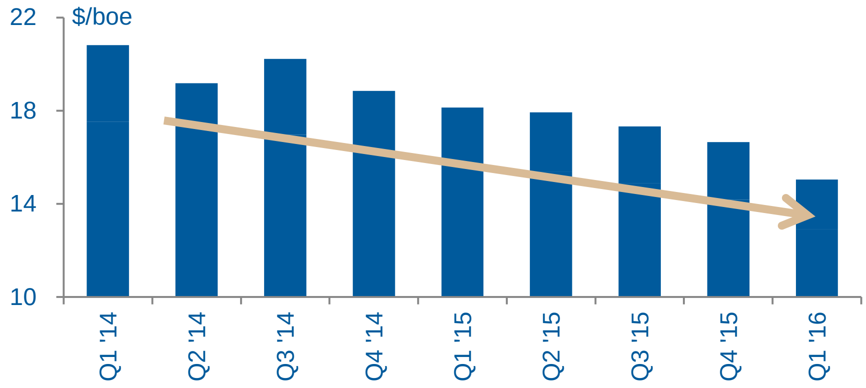


* Husky has redemption option.

Lowering Cost Structure to Enhance Free Cash Flow Profile

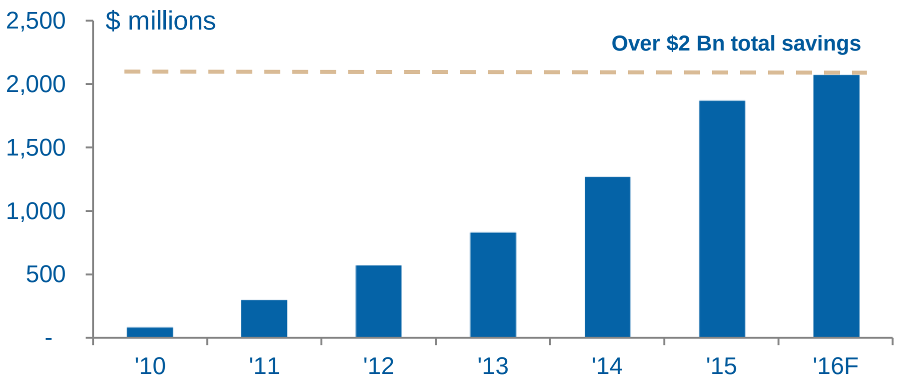
- ~20% sustaining and maintenance reductions
- Steady improvements in operating costs across the portfolio
- Ongoing reductions in SG&A
- Reducing working capital
- Transition to low sustaining capital production

Upstream Operating and Administration Costs*



* Excludes costs related to Sunrise Energy Project

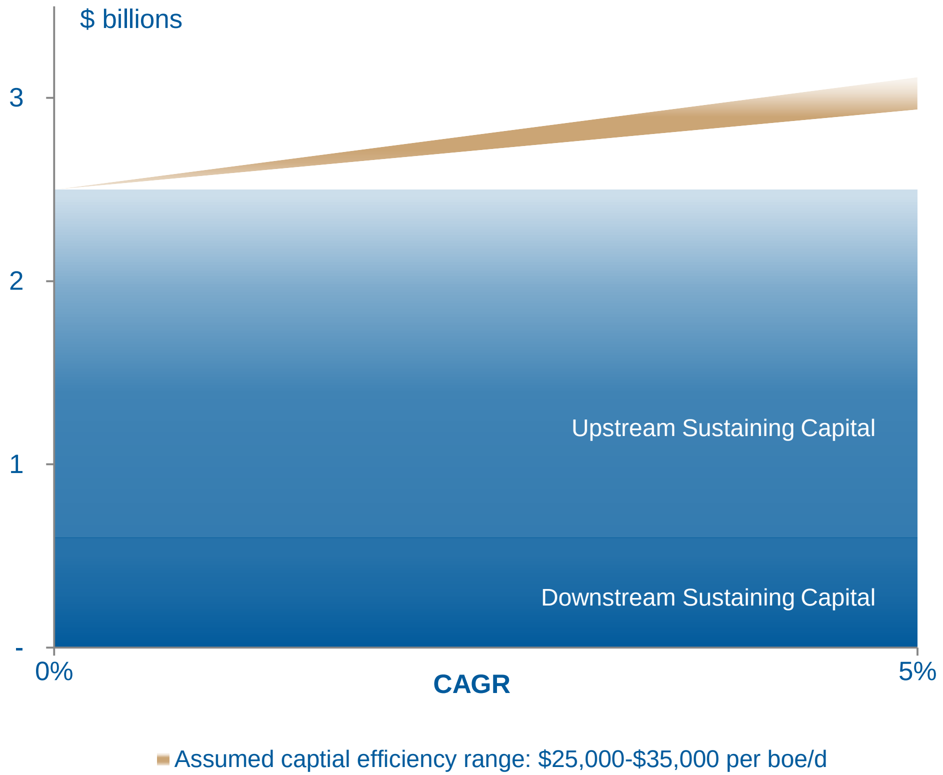
Cumulative Procurement Savings



Capital Efficient Investment Options

- Disciplined and paced investment approach
- High return organic portfolio

Illustrative Growth Capital Profile[1]



1. Illustration based on the following assumptions: 18% annual decline, new production added at $25,000 - 35,000 per bbl/d.

2016 Guidance Status

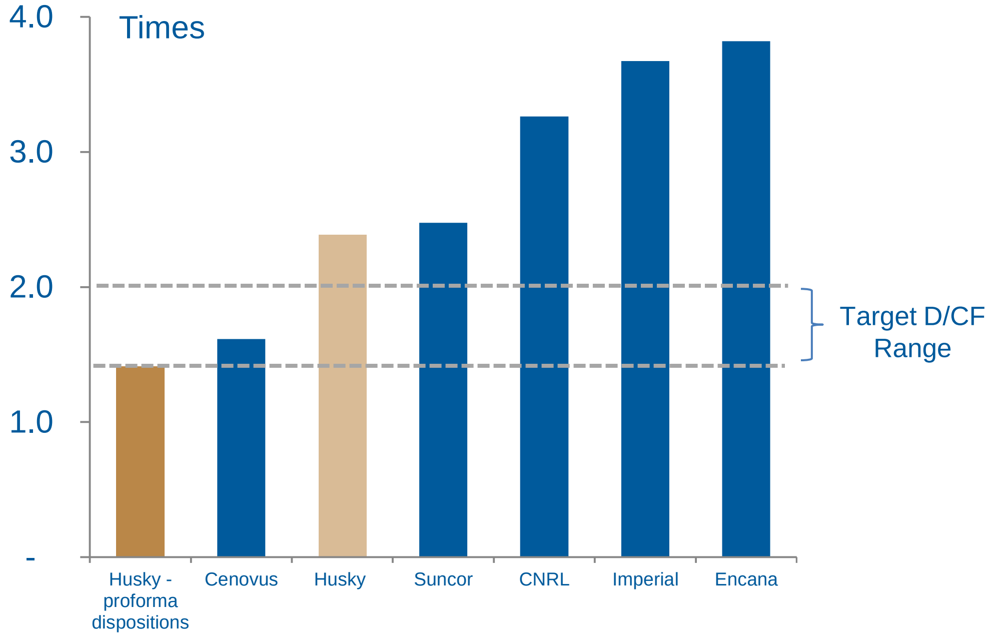
Metric	2016	Q1 ’16
Capital Expenditure	**$2.1 – $2.3Bn**	**$410MM**
Sustaining and Maintenance Capex	**~$2.5Bn**	**Annual**
Production	**315,000 – 345,000 boe/d** (excluding dispositions)	**341,300 boe/d**
Low Sustaining Capital Production	**~40%**	**32%**
Net Debt[1]	**$4.0 – $4.5Bn** (proforma dispositions)	**$6.97Bn**

1. 2016 proforma net debt calculated as net debt as of March 31, 2016, less expected proceeds from dispositions.

Sound Financial Plan

- Strong balance sheet
- Enhancing financial flexibility
- Lowering cost structure to enhance free cash flow profile
- Capital efficient investment options

Net Debt to Trailing Cash Flow from Operations

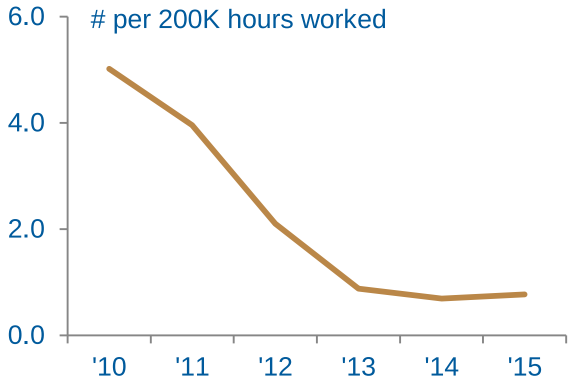


Portfolio Overview
Rob Peabody

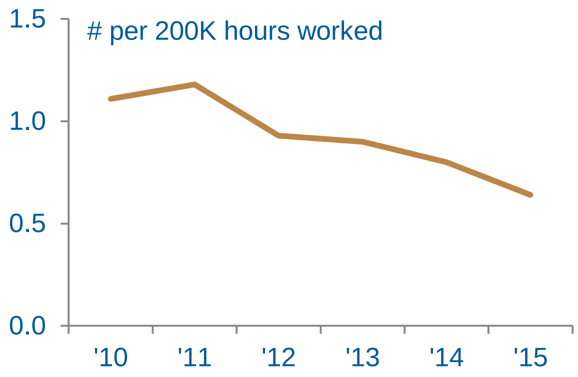
Improving Process Safety and Operational Reliability

- Critical and serious incidents down 94%
- Total Recordable Incident Rate down 45%

Critical & Serious Incidents



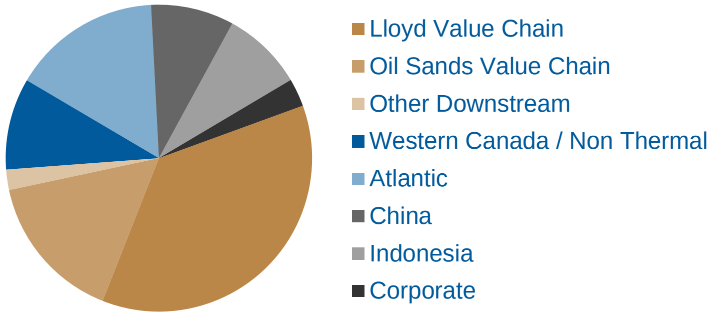
Total Recordable Incident Rate



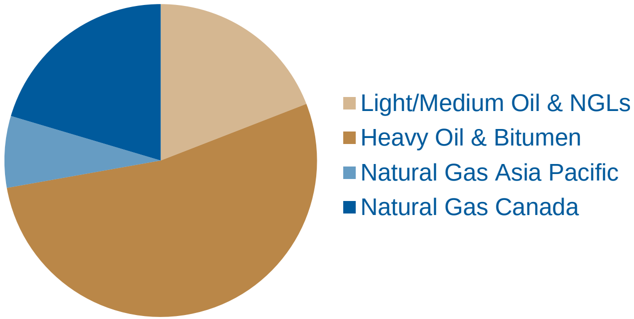
Diverse Portfolio of High Quality Growth Projects

- Large asset base profitable at low oil prices
- Optionality for short, mid and long cycle projects
- Geographic and product diversity
- Integration

Capex ’16F
($2.1-$2.3 Billion)



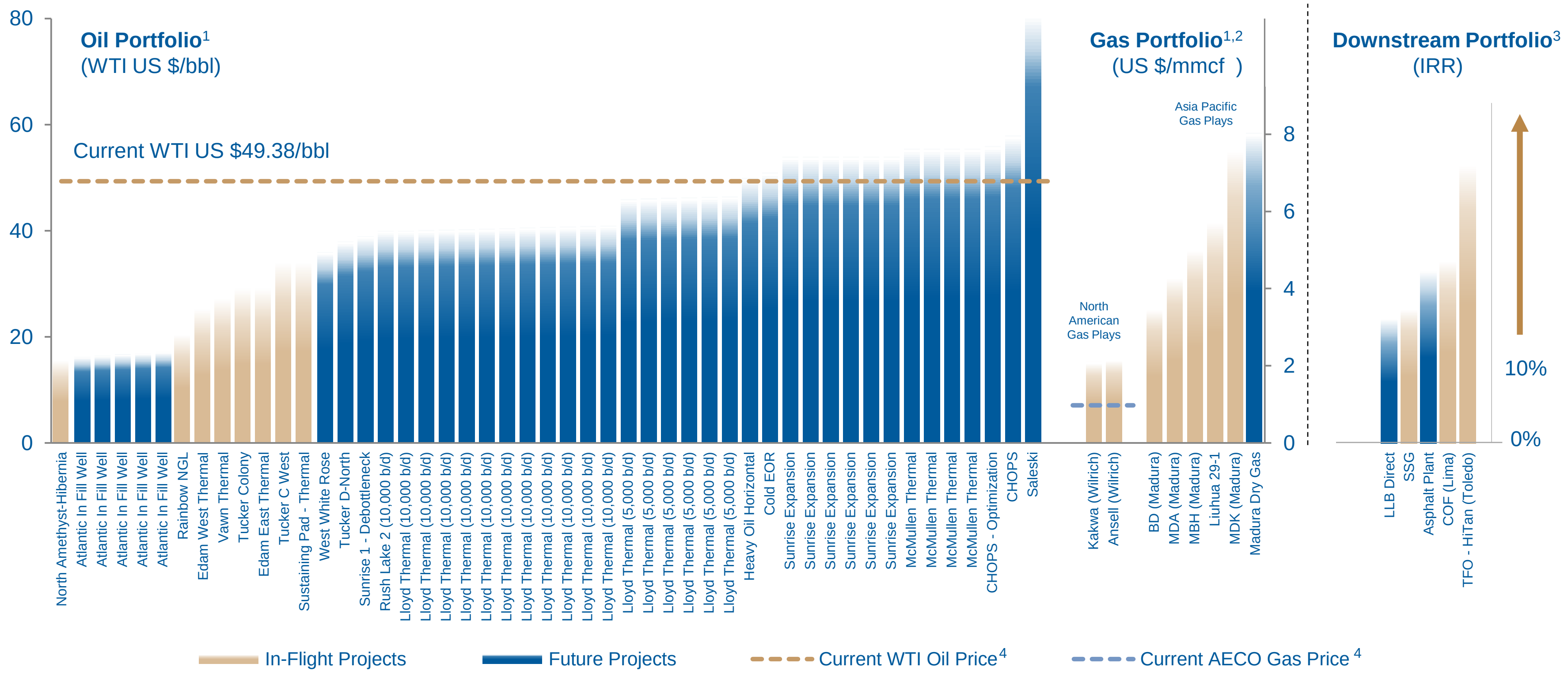
Production ’16F
(315,000 – 345,000 boe/d)[1]



1. Production guidance range excluding dispositions

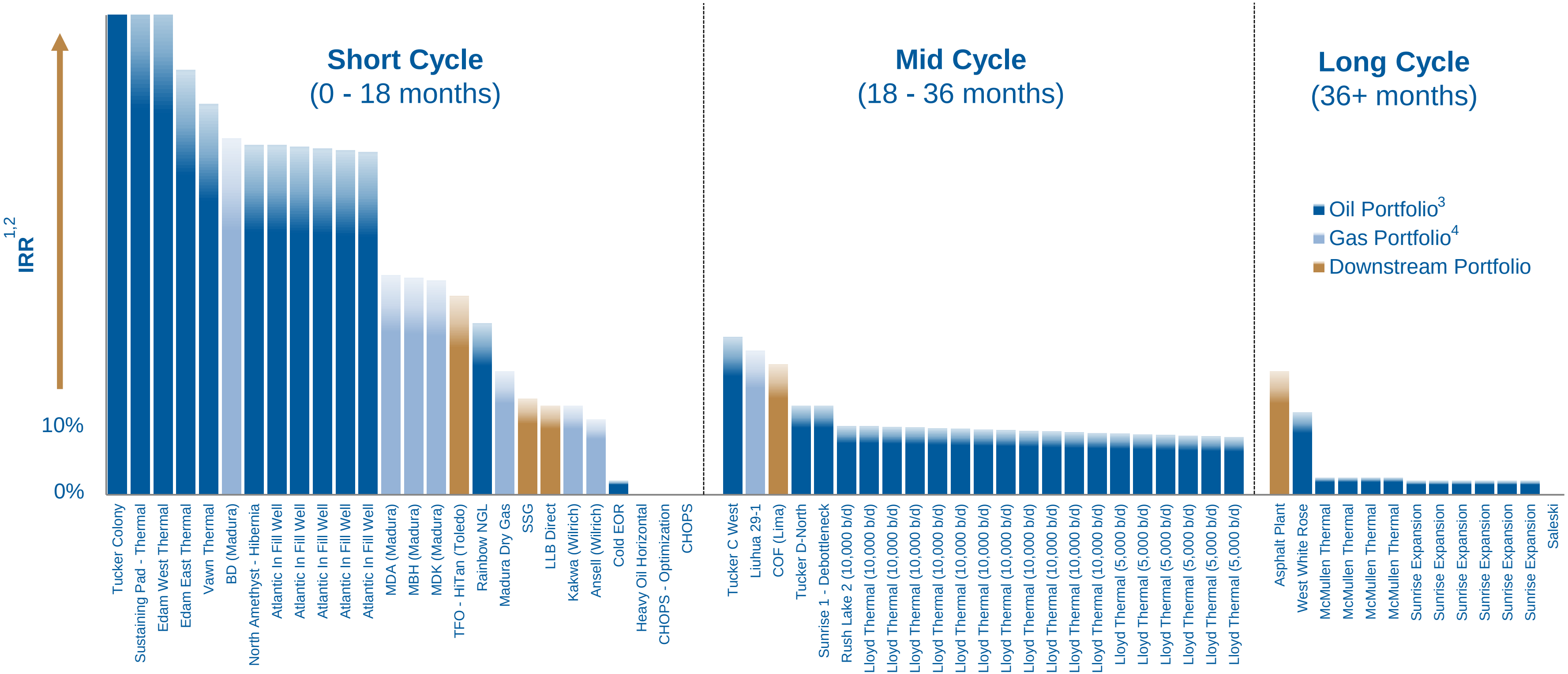
Opportunity Rich . . . Even At Low Prices

Price Required to Generate 10% IRR



1. Other than as indicated in the Advisories, 10% IRR calculations are based on 2P reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on US$40 WTI price scenario.
3. Downstream portfolio IRR not directly tied to oil or gas price. See Advisories for further detail.
4. WTI and AECO prices as of May 27, 2016. AECO gas price converted to US$ at a CAD/USD 0.75 exchange rate.

Investment Flexibility . . . Maximizing Returns



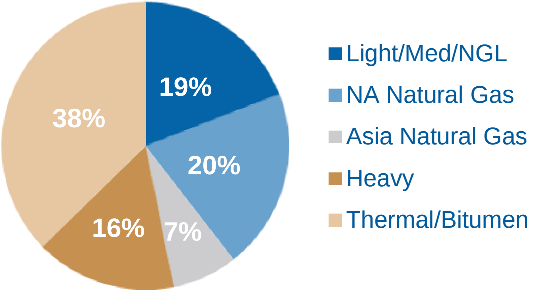
1. IRRs for projects currently in-flight reflect go forward economics. IRRs for projects not started reflect full cycle economics.
2. Other than as indicated in the Advisories, 10% IRR calculations are based on 2P reserves.
3. Oil portfolio IRR calculated based on US$40 per barrel WTI price scenario.
4. Gas portfolio IRR calculated based on $3.00 per mmcf AECO price scenario with US $40 per barrel; WTI price scenario for associated liquids.

Focused Diversity Minimizing Risk

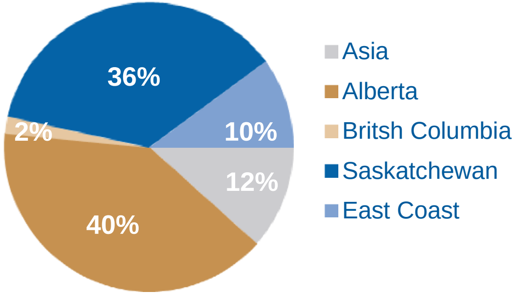
- Geographic and product diversity
- Large asset base, profitable at low oil prices
- Modest capital required for growth

Upstream Production Mix ('16E)

Products



Geography



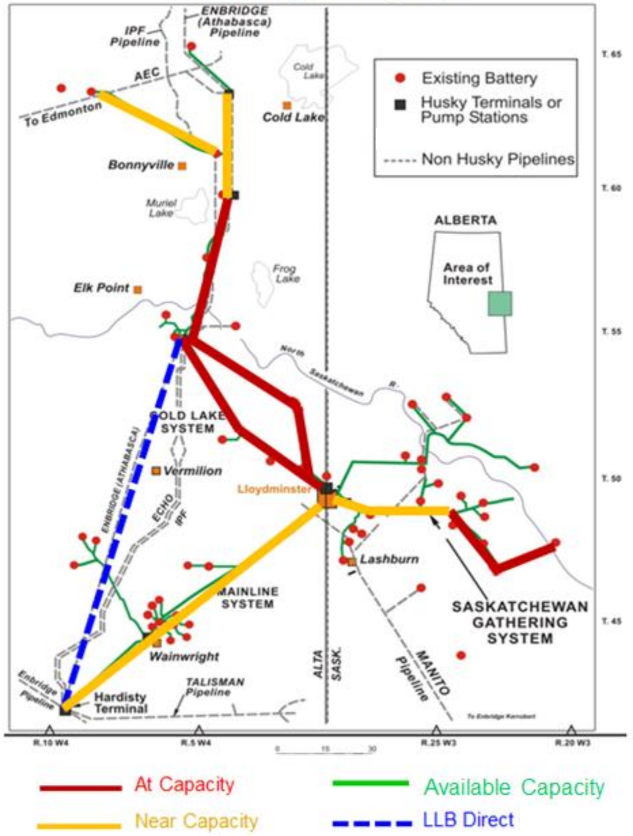
Integrated Portfolio

Rob Peabody

Midstream Transaction – Strategic Value Creation

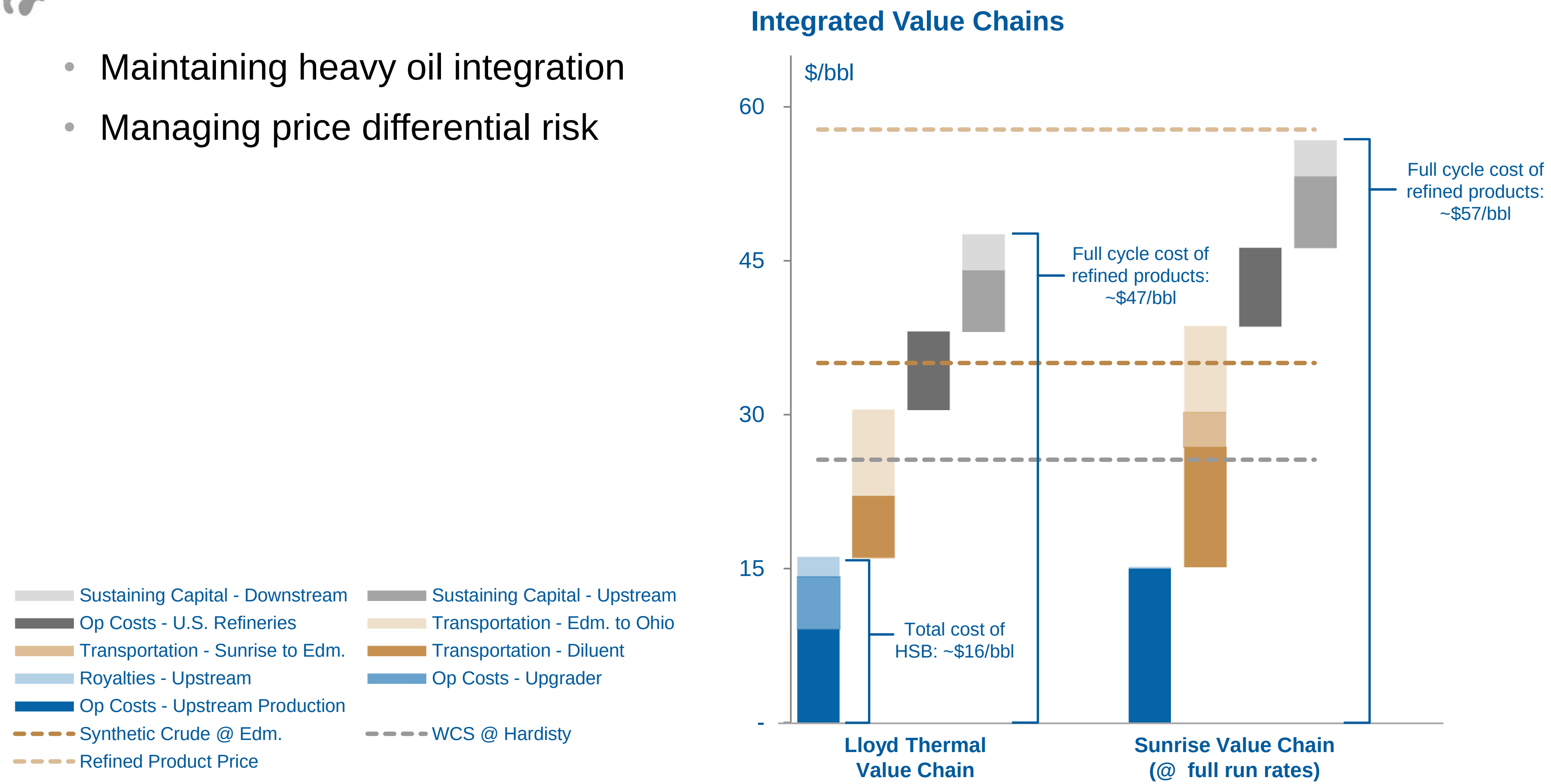
- Husky to retain 35% ownership and operatorship
- 1,900 kilometres of pipeline in Lloyd region
- 4.1 million barrels of oil storage at Hardisty and Lloyd
  - Other ancillary assets
- Well-funded partners fully committed for additional growth
- Partnership has secured ~$750 million in future financing
  - Locks in next leg of capital funding for growth, including northern leg of SGS and LLB Direct
  - Capacity for next eight thermal projects

Current System Capacity



Focused Integration Enhancing Returns

- Maintaining heavy oil integration
- Managing price differential risk



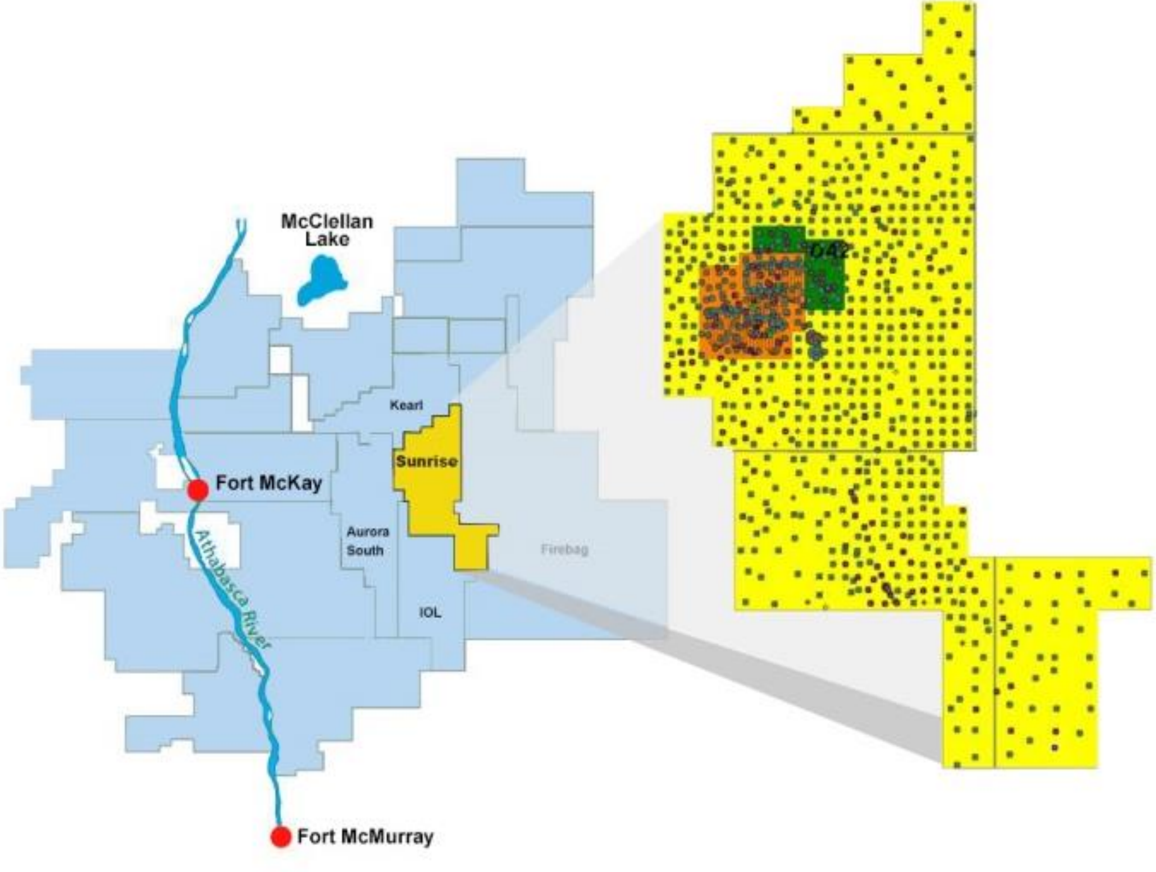
- All crude prices and $/bbl costs reflect 1Q/2016 averages. All values in $CAD based on 0.75 CAD/USD exchange rate.

Oil Sands

John Myer

Successful Start Up

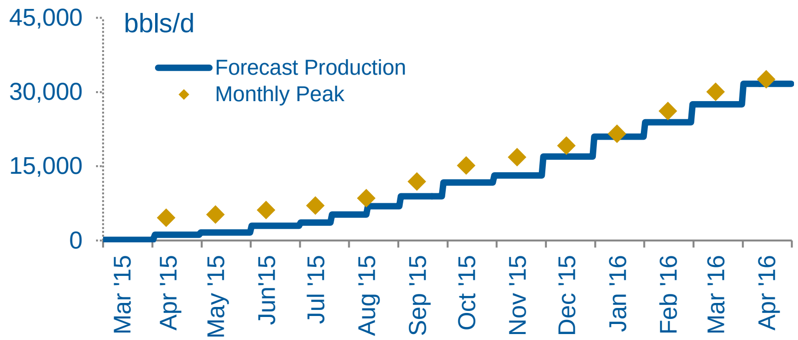
- Steady production gains
- Fully commissioned Plants 1A & 1B
- Toledo Refinery important link of Sunrise Value Chain
- Approved future development of 140,000 bbls/d (gross)
- Optimization opportunities



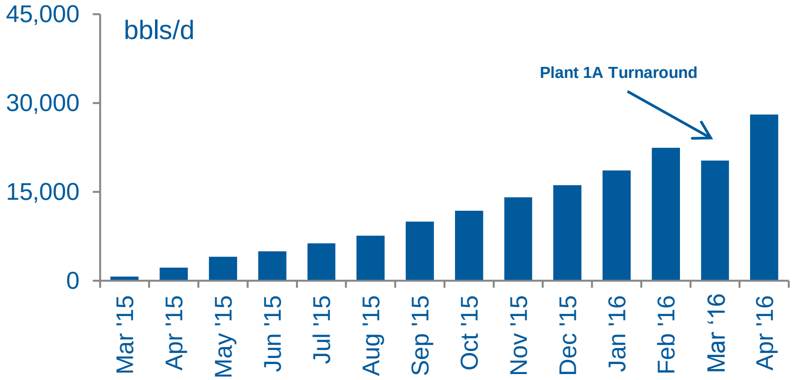
Steady Production Growth

- Paced ramp-up
- Lower temperature, lower pressure reservoir achieving expected results
- 55 well pairs on production

Sunrise Oil Sands Daily Production vs. Forecast

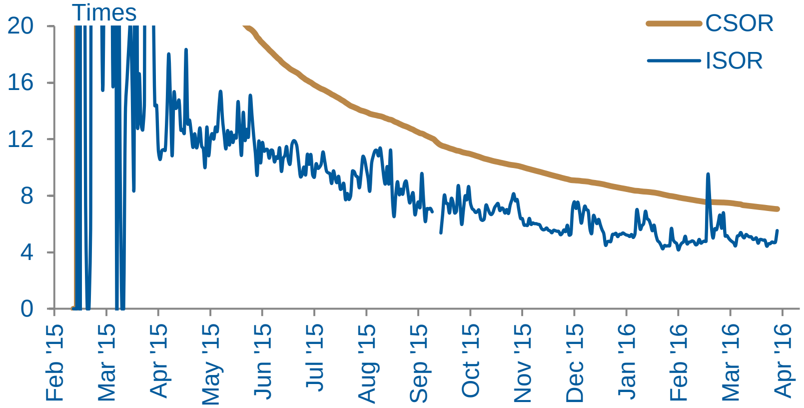


Average Monthly Production

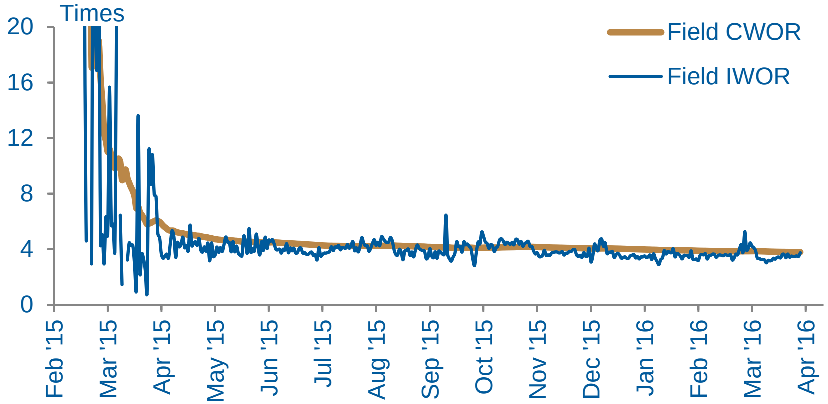


Sunrise Dashboard

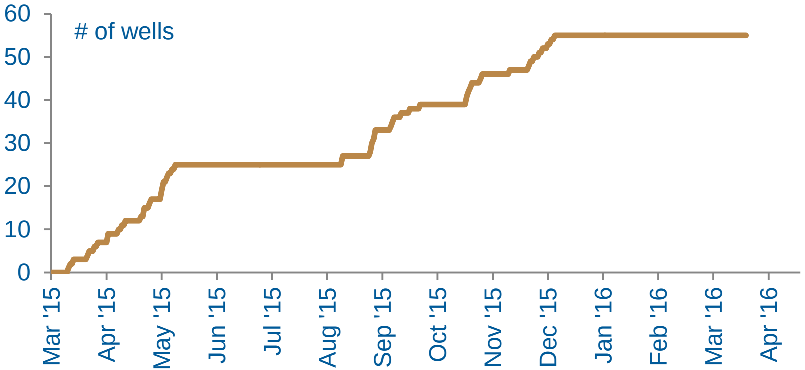
Steam Oil Ratio



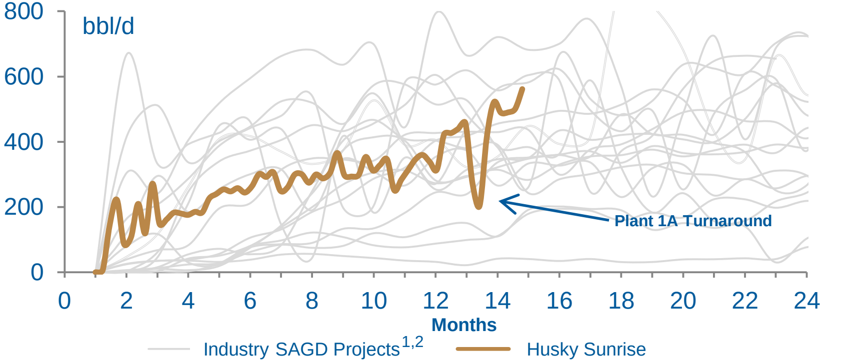
Water Oil Ratio



Number of Wells on Production



Normalized Bitumen Rate per Well



1. Data Source: AccuMap
2. Projects compared: ConocoPhillips Surmont, Devon Jackfish 1, Devon Jackfish 2, Suncor Firebag 1, MEG Christina Lake Phase 1 & 2, Southern Pacific Mckay, Suncor Mackay River, Connocher Great Divide, Nexen Long Lake, Statoil Leismer, Cenovus Foster Creek A, Cenovus Christina Lake 1A

Restart of Operations

- Wildfire prompted industry-wide response
- Safe and orderly shut down of Sunrise
- No damage to facilities

Sunrise Energy Project

Optimization Opportunities

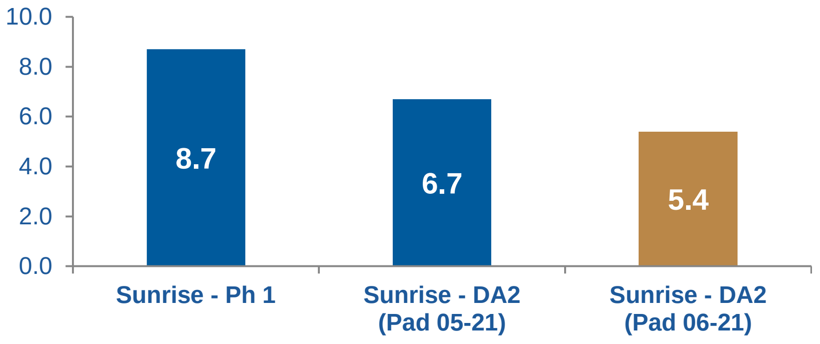
- De-bottlenecking opportunities expected to surpass nameplate capacity
  - Re-rating capacity of steam generators
  - Learnings from start up will result in faster, more efficient new well starts
  - Sustaining pads available for future production
  - Performance testing expected to confirm capacity for further opportunities

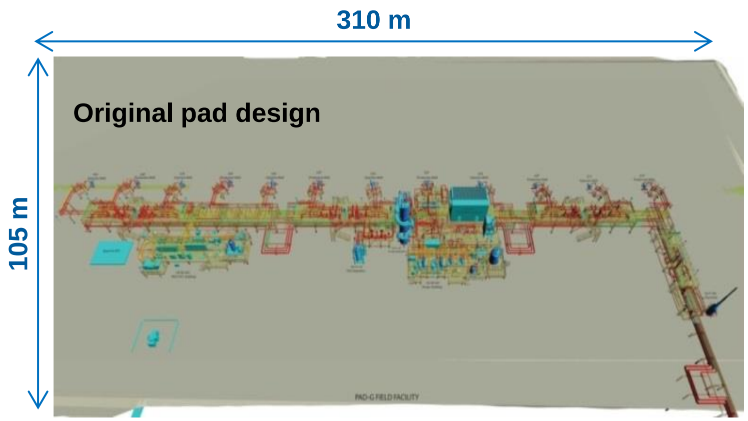
Sunrise Energy Project

Step Change in Sustaining Capital Efficiency

- Customized ‘walking’ rig reduces sustaining pad size and cost
- Pad size decreased by 50%
- Small, modular facilities lead to lower costs
- 30% reduction in sustaining capital (2/3 of total project cost is sustaining capital)

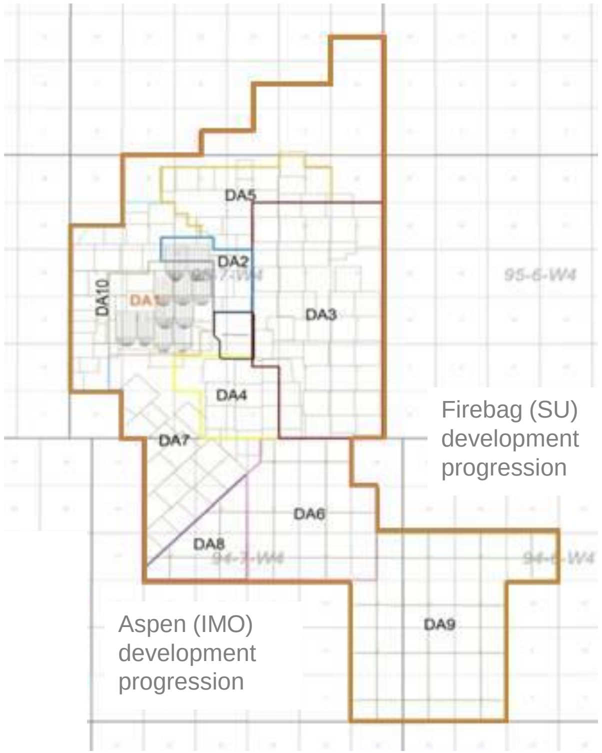
Drilling Days Per Well





Future Growth Potential

- Build on success and lessons learned
- Leveraging existing infrastructure
- Modular development approach to future phases (20,000 - 30,000 bbls/d)
- Regulatory approval for an additional 140,000 bbls/d
- Further potential across the lease



1 cm = 407.0 m

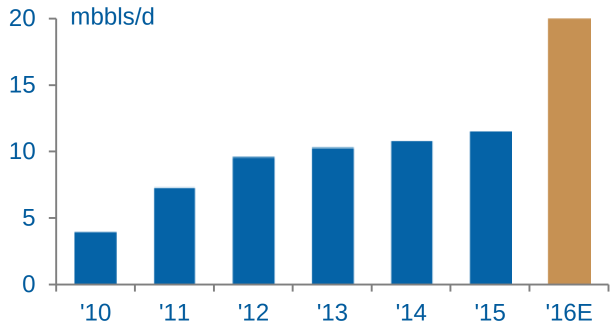
Heavy Oil

Ed Connolly

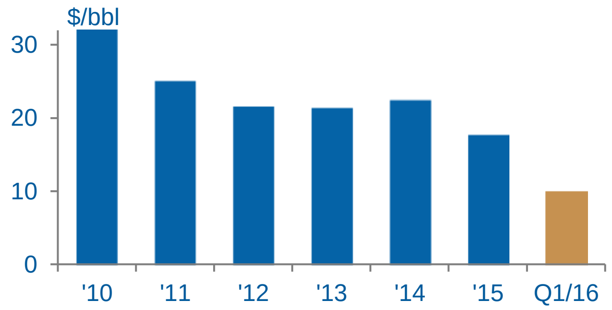
Tucker Thermal Project

- Enhancing project development
- Production has exceeded target of 20,000 bbls/d by end of ’16
  - Clearwater pad (Q4/15 – 5,000 bbls/d)
  - Colony formation (Q2/16 – 5,000 bbls/d)
- Reduced operating costs to ~ $8/bbl
- Improved understanding of subsurface
- Improved drilling methods
  - SOR improved to 3.5x from 6.7x in 2015
  - Low cost production adds utilizing existing plant
- Earnings break even at ~ $35 WTI

Tucker Production



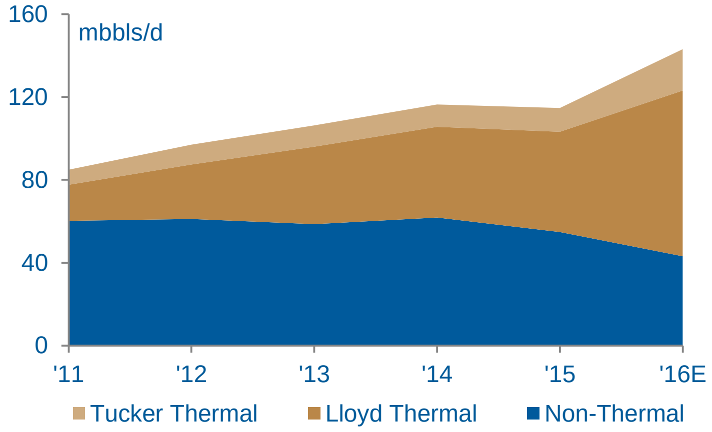
Tucker Operating Costs



Thermal Transformation

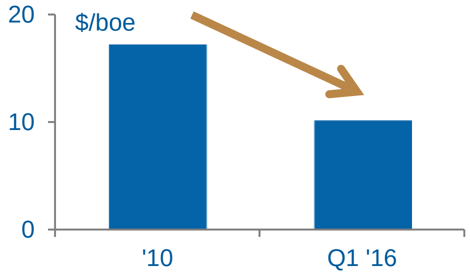
- Shifting from conventional CHOPS to proven thermal formula
- Thermal growth from 22,000 bbls/d in ’10 to more than 100,000 bbls/d by end ’16
    - 10 developed projects at Lloyd
    - Rejuvenated Tucker Thermal Project
- Potential of over 12 x 10,000 bbls/d and 6 x 5,000 bbls/d additional Lloyd thermal projects

Heavy Oil Production



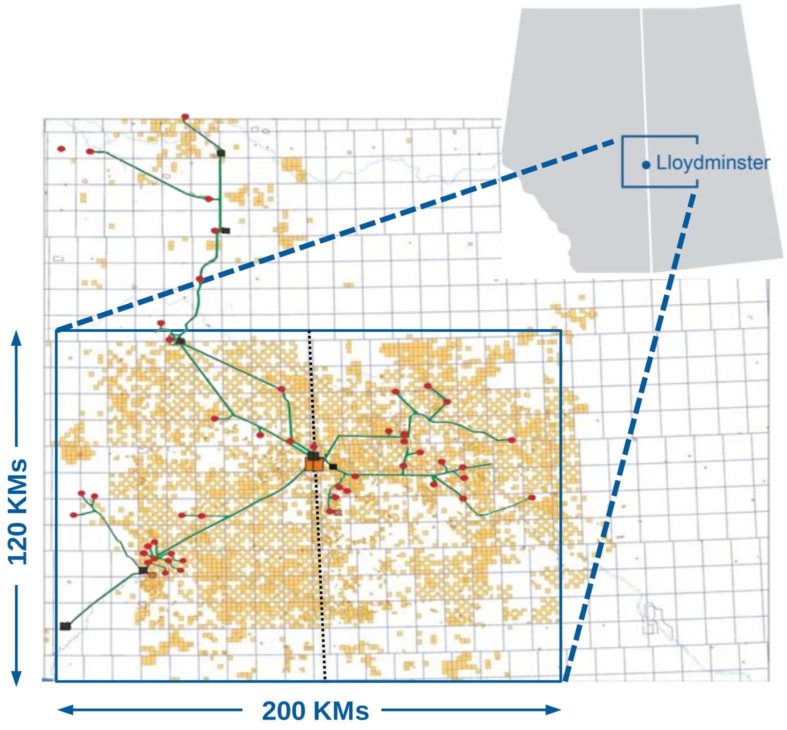
Total Heavy Oil Operating Costs

(Thermal and non-thermal)



Unmatched Land and Infrastructure Position

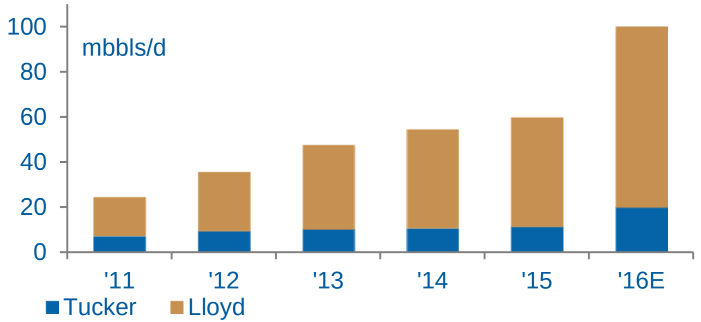
- 2.2 million net acres
- 1,900 kilometres of gathering system and pipelines
- Combination of fee-simple and Crown lands enhance the economics
- Detailed understanding of subsurface
  - 3D and 2D seismic over entire block
  - 65,000+ well logs analyzed
- Improving recoveries through thermal and other technology applications



Thermal Efficiencies

- Improving capital efficiencies
  - Cut and paste approach
  - Modular construction
  - Sequential build program
- Lowering sustaining capital
- Reducing operating costs
- Long life resources
- Higher price realizations (vs. bitumen)

Thermal Production



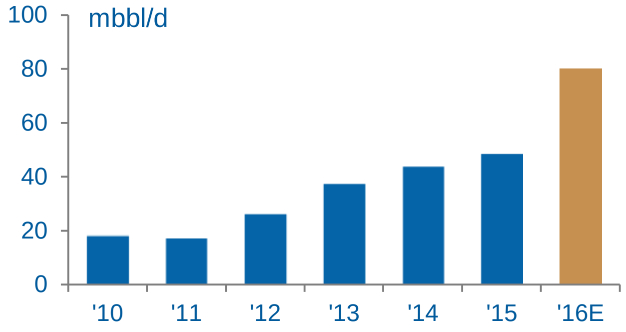
Thermal Project Characteristics	Tucker Thermal Production	Lloyd Thermal Production
Build Costs[1] $MM	-	$350
Op Cost $/bbl	$8-9	$7-8
Royalty Rate	2%	7%
Crude Quality	8º-12º	10º-12º
Differential to WCS $/bbl	~$5	~$2
DD&A/bbl	~$14	~$11
Sustaining Cost $/bbl	$5-7	$5-7
Project Life	>40 yrs	>15 yrs
Reserve Recoveries	>50%	>60%

1. Per 10,000 bbls/day project.

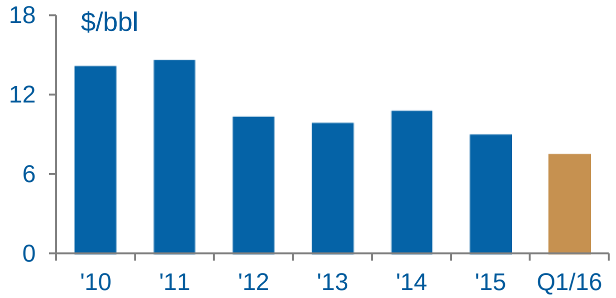
Higher Quality Barrels

- Lloyd thermal production to exceed 80,000 bbls/d by end of ’16
- In-flight projects to add ~24,500 bbls/d of nameplate capacity by the end of ’16:
  - Edam East - 10,000 bbls/d *(on production)*
  - Vawn - 10,000 bbls/d *(steaming)*
  - Edam West - 4,500 bbls/d *(commissioning)*

Lloyd Thermal Production



Lloyd Thermal Operating Costs



The Future of Lloyd Thermals

- Four 10,000 bbls/day projects ready for sanction
- Identified projects for future growth
  - Eight x 10,000 bbls/d
  - Six x 5,000 bbls/d
- Development pace to match cash flow

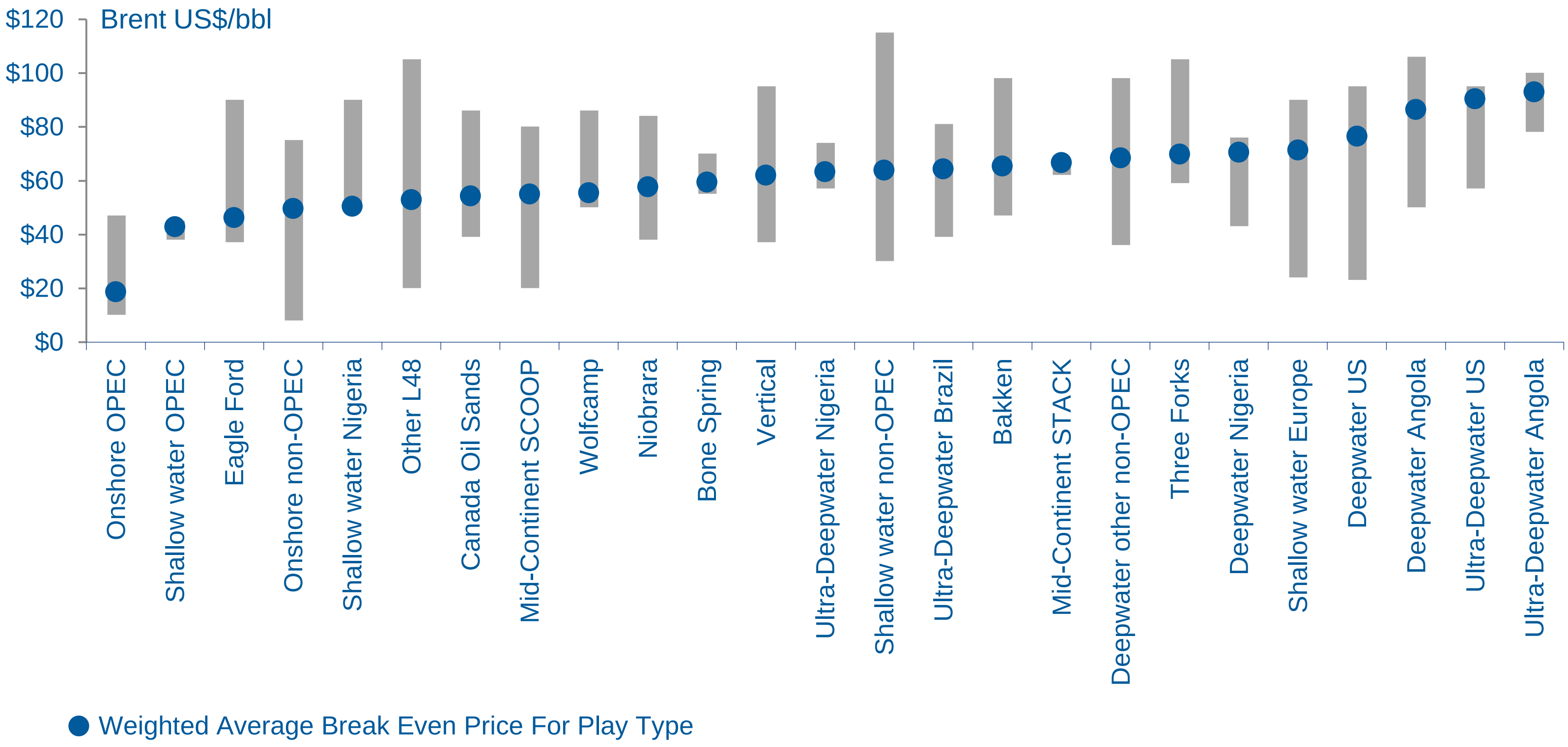
Lloyd Thermal Project Inventory

Status	Project Name	First Oil Date	Current/ Forecast Net Production Rate* (bbls/d)	~Barrels Produced (mm/bbls)
Producing	Pikes Peak	'84	4,400	75.4
	Bolney Celtic	'96	9,250	35.9
	Celtic	'96	9,250	34.5
	Paradise Hill	'12	4,000	6.0
	Pikes Peak South	'12	11,000	18.0
	Sandall	'14	5,100	4.2
	Rush Lake	'15	12,500	5.4
	Edam East	'16	10,000 (nameplate)	0.02
2H 2016 Start Ups	Vawn	Q3 '16	10,000	
	Edam West	Q3 '16	4,500	
Ready for Sanction	Rush Lake 2 (sanctioned)	'17- '21	10,000	
	Lloyd Thermal 2		10,000	
	Lloyd Thermal 3		10,000	
	Lloyd Thermal 4		10,000	
Identified	2021+ Lloyd Thermals: 5 through 18 6 x 5,000 bbls/d & 8 x 10,000 bbls/d			

*As of May 16, 2016

Lloyd Thermals – Globally Competitive

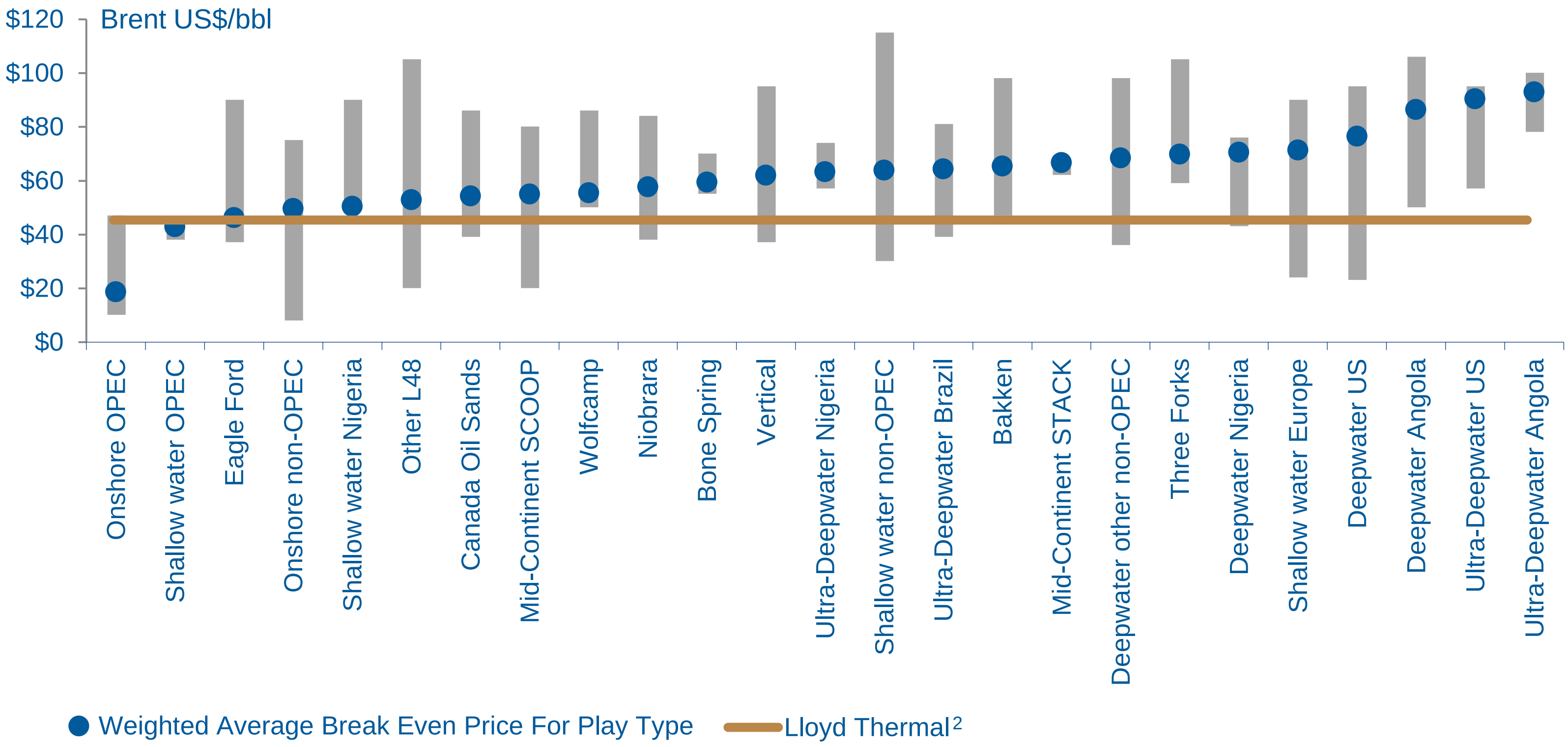
Breakeven at 10% IRR[1]



1. Source: *Pre- FID oil Projects: Global breakeven analysis and cost curves* (Wood Mackenzie Corporate Service), January 2016.

Lloyd Thermals – Globally Competitive

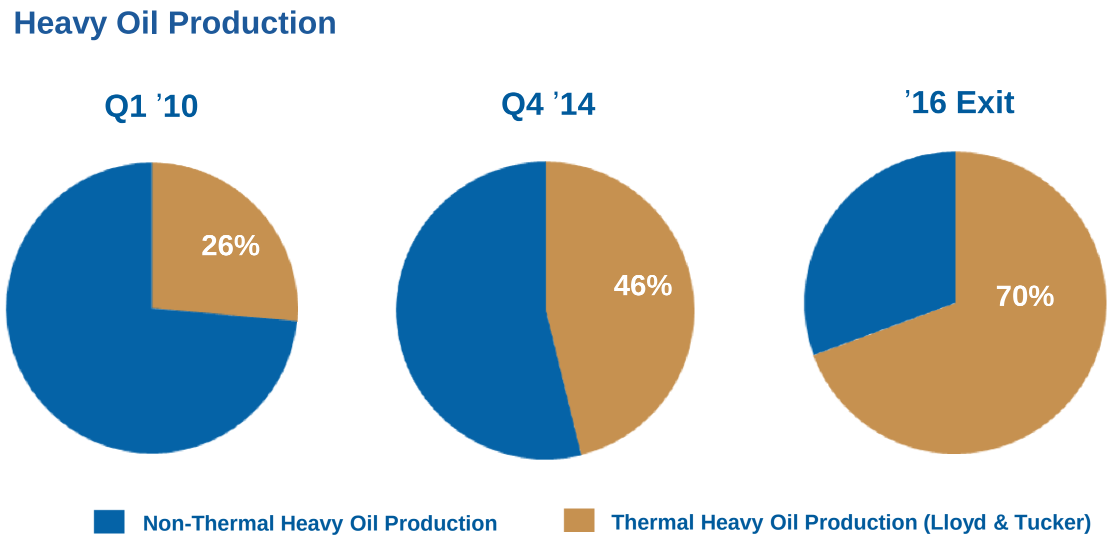
Breakeven at 10% IRR[1]



1. Source: *Pre- FID oil Projects: Global breakeven analysis and cost curves* (Wood Mackenzie Corporate Service), January 2016.
2. Lloyd thermal break-even oil price based on internal estimates. See Advisories with respect to Lloyd Thermal resource estimates.

New Growth Engine

- Thermal low sustaining capital projects adding to overall higher quality production
- Vast resource potential
- Proven thermal development formula
- Improving capital efficiencies

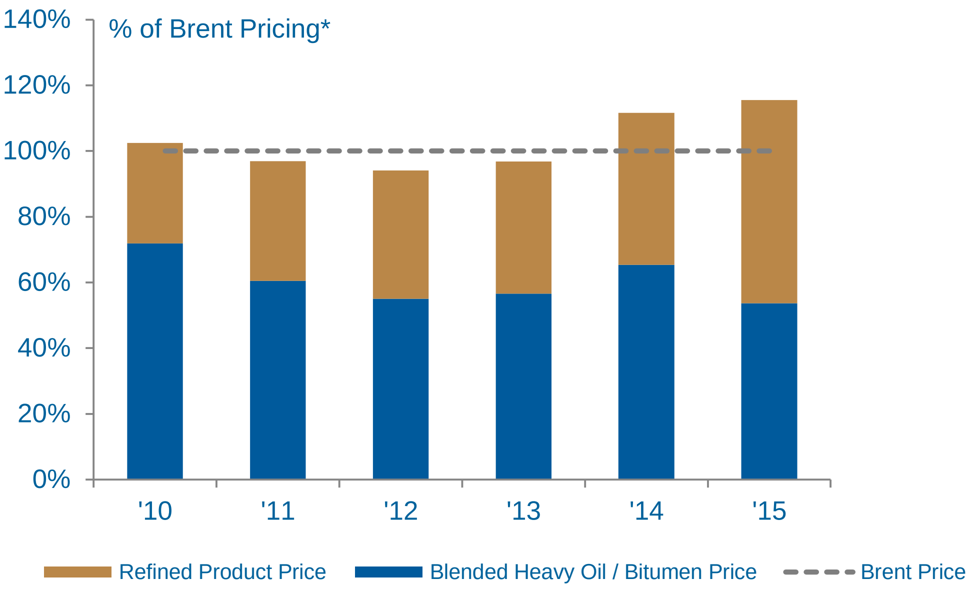


Downstream

Bob Baird

Margin Business Stabilizing Cash Flow and Earnings

- Improving refinery flexibility and pipeline capacity
- Increasing storage capability
- Diversified market access capturing margins
- Integrated Sunrise and Lloyd Value Chains
- Increasing retail network profitability
- Improving uptime and reliability reducing costs



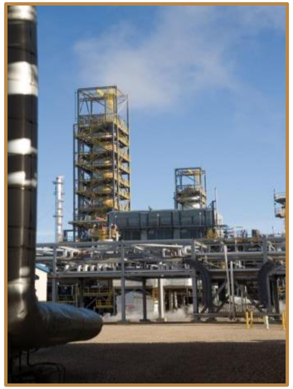
* Brent prices converted to Canadian dollars at average annual USD/Cdn exchange rate

Competitively Advantaged Assets

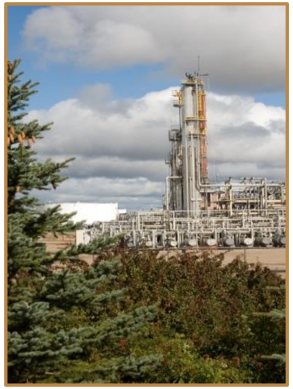
- Total throughputs 308,000 bbls/d in ’15
- Total refining and upgrading capacity of 335 mbbls/d
  - Light/Synthetic: 175 mbbls/d
  - Heavy/Bitumen:150-160 mbbls/d
- Improving refinery flexibility, matched to heavy oil and bitumen production growth
  - Hi-TAN project, Toledo (’16)
  - Lima Crude Oil Flexibility Project (’18-’19)
  - Lloyd asphalt refinery

Hardisty
(3.1 mmbbls storage/blending)

Lloyd Upgrader
(80,000 bbls/d)

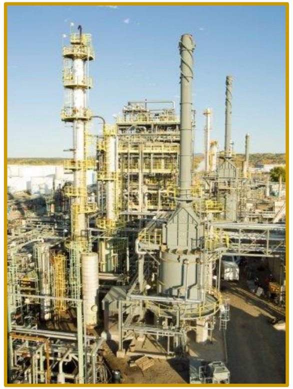


Lloyd Asphalt Refinery
(29,000 bbls/d)



Lima Refinery
(160,000 bbls/d)

Toledo Refinery
(140,000 bbls/d)*



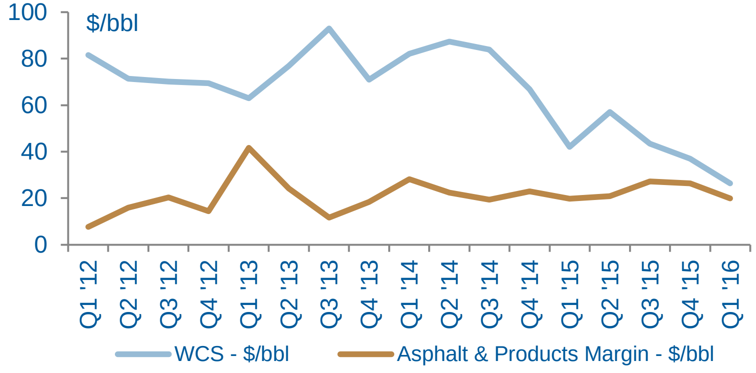
Prince George Refinery
(12,000 bbls/d)

* Husky Energy has a 50% ownership interest in the Toledo Refinery (operated by BP PLC)

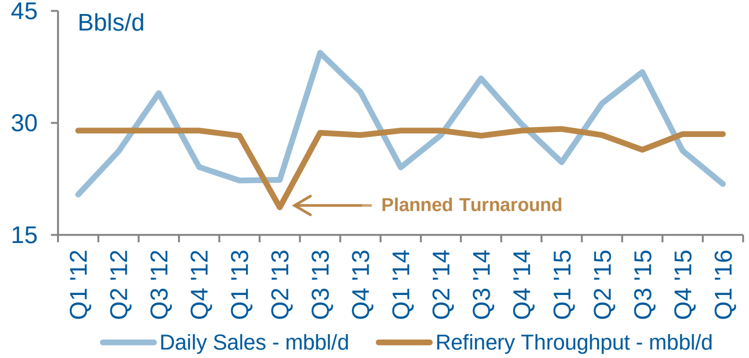
Lloyd Asphalt Refinery Cash Flow Generation

- Strong cash flow contributor
  - Annual EBITDA[1] ~$200 million
  - Margins ~$20/bbl
  - Operating costs ~$4/bbl
- Reliable operations
  - Three-year average uptime of 97%
- Largest producer of asphalt in Western Canada, representing:
  - 20% of Western Canadian production
  - 5% of North American production

Maintaining Asphalt Margin



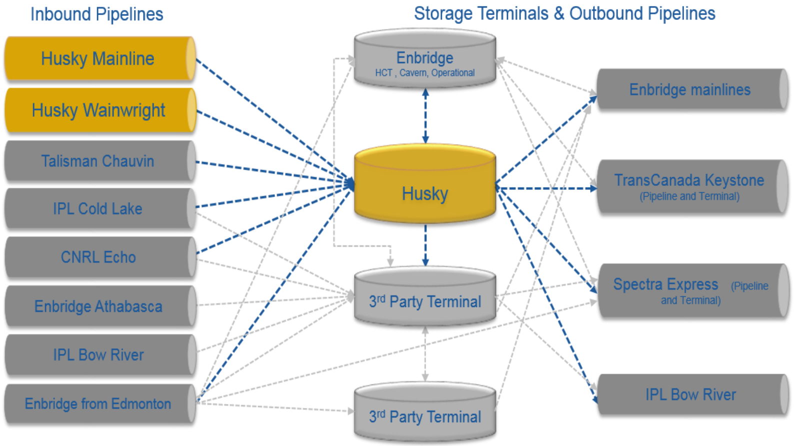
Asphalt Refinery Sales Volume



1. Non-GAAP measure. See Advisories for further details.

Storage Terminals / Connectivity Provides Advantage

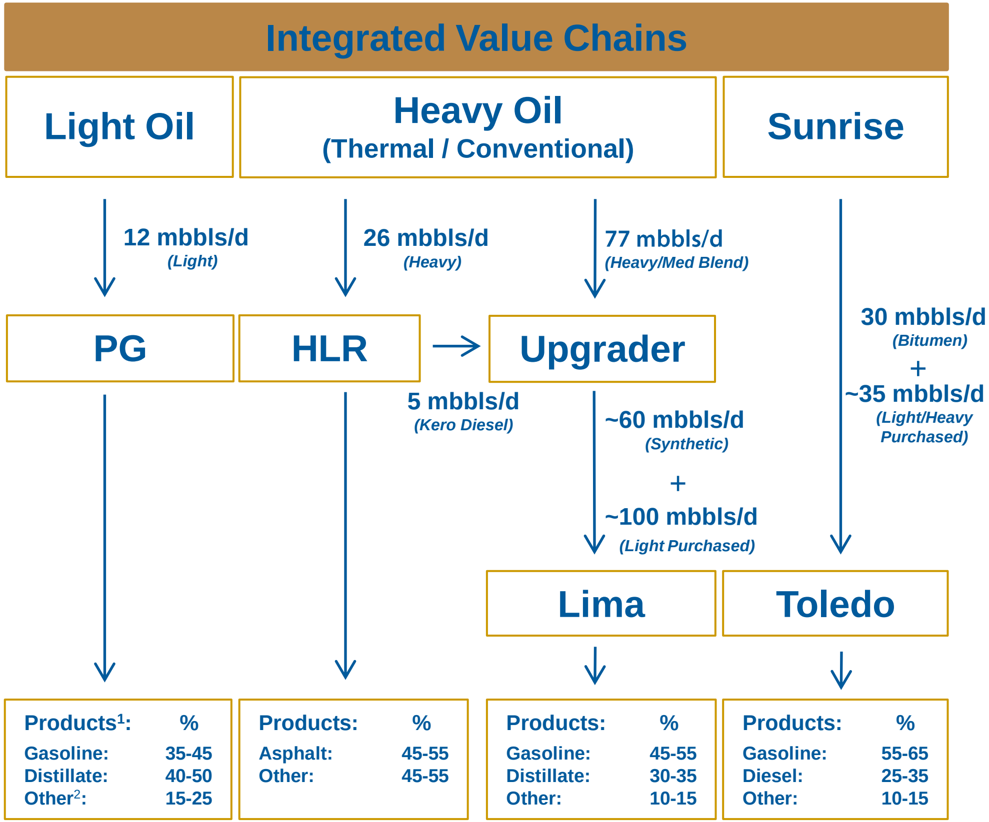
- Operator and equity owner of heavy oil pipeline system[1]
  - Opportunities for growth
- Strategically placed storage capacity
  - Hardisty Terminal[1]: > 3.1 million barrels
    - Founding member and blender of Western Canadian Select (WCS)
    - Operational and storage tank space to customers
  - Lloyd Terminal[1]: > 1.0 million barrels
- Diversified market access strategy
  - Connected to all key export markets
  - Secured capacity on major pipelines



1. Following final regulatory approval, Husky Energy will hold a 35% working interest in the newly formed limited partnership that owns these assets

Maximizing the Hydrocarbon Value Chain

- Physical integration capturing full value
  - Integrating Upstream production planning
  - Mitigating differentials
  - Realizing refined product pricing
- Initiatives to enhance returns and cash flow
  - $117 million savings to date



1. Product variability can be influenced by several factors, including seasonal demand, access to feedstock, distribution system interruptions.
2. Other products include propane, benzene, Sulfur, LPG, LVGO, HVGO, Heavy Fuels, petro chemicals and other various by-products.

Growing With Lloyd Thermals and Sunrise

- Two integrated value chains
- Midstream infrastructure expansion funding
- Numerous high return Downstream projects
- Built-in home for growing thermal production
- Maximizing margin capture from every barrel

Q&A

Break

Portfolio Overview

Rob Peabody

Western Canada and Offshore Portfolios

- Western Canada transformation
  - Current resource play production of ~40,000 boe/d
- Asia Pacific and Atlantic operations
  - Current net offshore production capacity of ~90,000 boe/d

Ansell

Liwan Gas Project

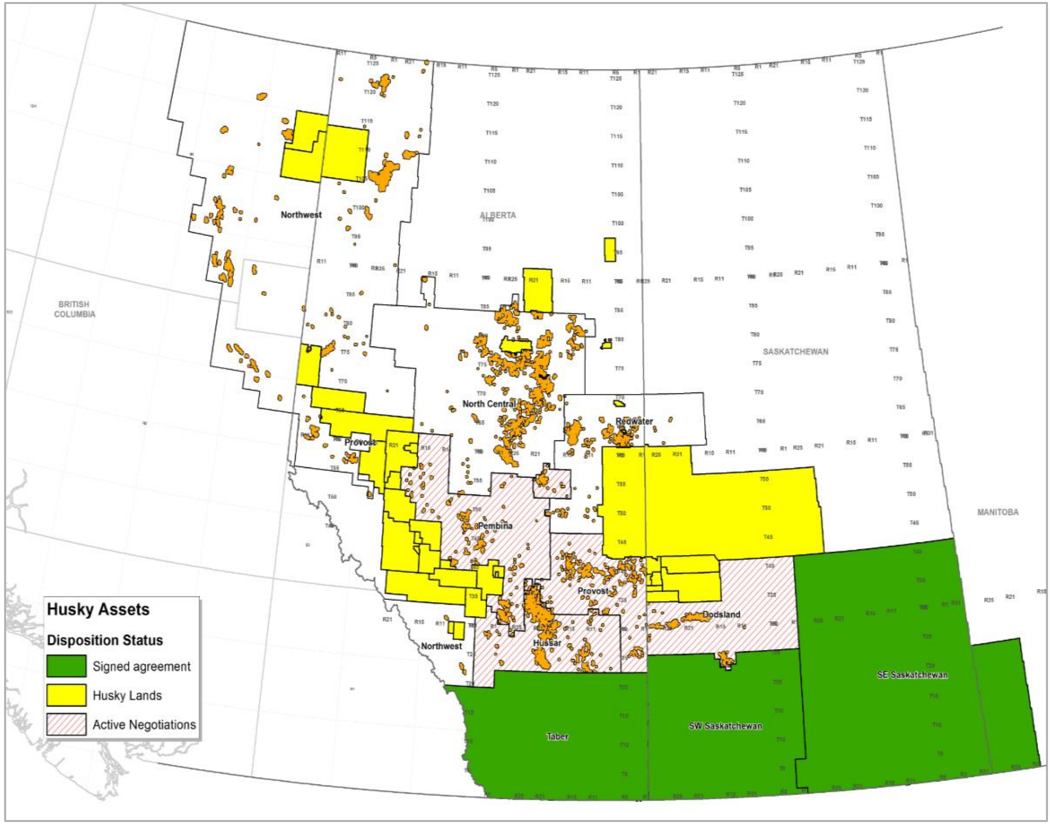
SeaRose FPSO

Western Canada

Rob Symonds

Rejuvenating Western Canada

Asset	Description	Expected Gross Proceeds
Royalties[1]	~1,700 boe/d	$163MM
Western Canada[2]	~20,600 boe/d	$900MM
Total	**~22,300 boe/d**	**$1.1Bn**
Expected Sales	~11,000 boe/d	In discussion

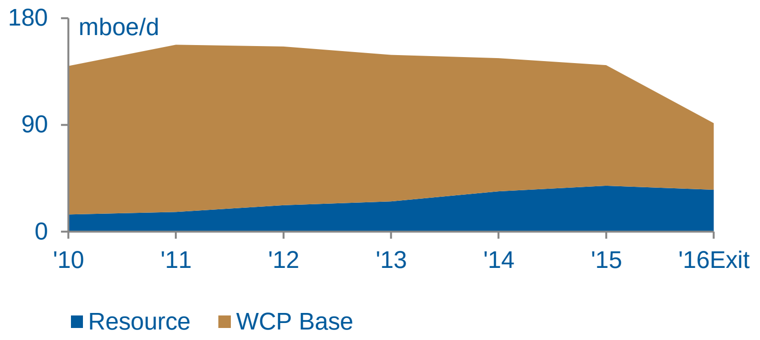


1. Transaction closed May 25, 2016.
2. Purchase and Sale Agreements signed.

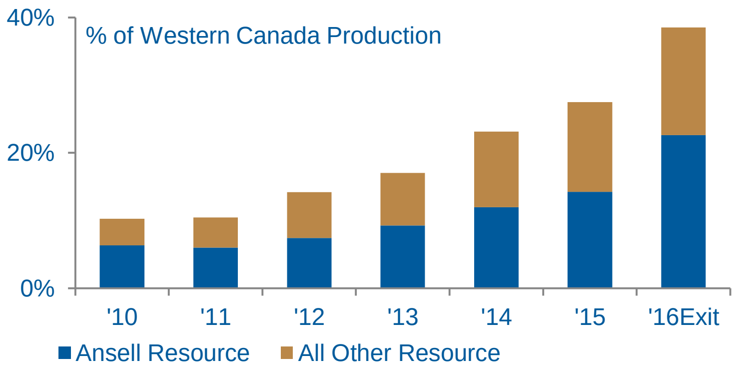
Expanding Resource Play Production

- Expanding resource play production
  - Focus on high return, high productivity wells
- Identifying further efficiencies
- Transitioning legacy asset base
- Targeting high return, high productivity wells
- Focusing on fewer plays in key areas
  - Wilrich: Ansell, Kakwa
  - Montney, Duvernay

Western Canada Production

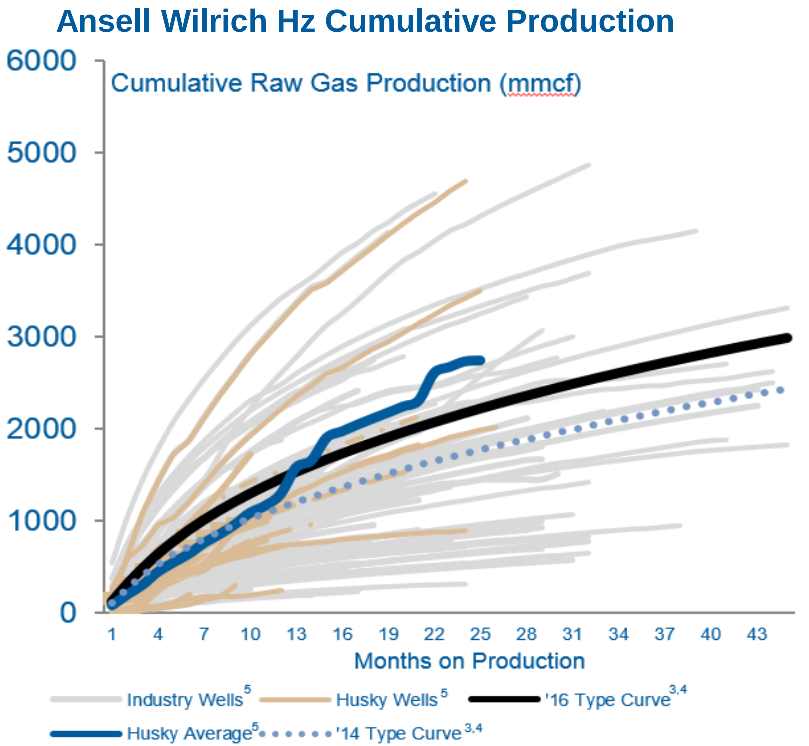


Resource Play Production



Ansell Opportunity

- Ansell
  - Current production 23,000 boe/d[1]
  - Flexible asset, room to grow
    - >650 potential drilling opportunities[2]
    - Multiple formations
    - Current priority – Wilrich
  - Driving costs down
    - Well costs of $4.8 million today vs. $9 million in ’14
  - Forecast reserves improvement[3,4]
    - Wilrich EUR of 1,013 mboe/well today vs. 833 mboe/well in ’14



Well data as of January 12, 2016.

1. Current production from all zones.
2. Drilling opportunities split: Proved Undeveloped (75), Probable (56), Best Estimate Contingent Resource (542).
3. Husky type curves and EUR reflects the unrisked, Proved plus Probable estimate.
4. Prepared by a qualified reserve engineer and according to COGEH.
5. Husky Wells, Husky Average and Industry Wells based on production data. See Advisories for details.

Asia Pacific Region

Kevin Moore

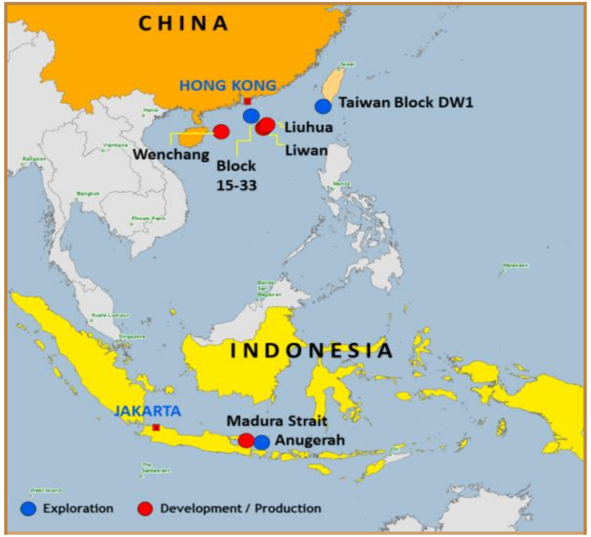
Asia Pacific Portfolio

China

- Liwan Gas Project
- Wenchang oil field
- Liuhua 29-1
- Offshore exploration

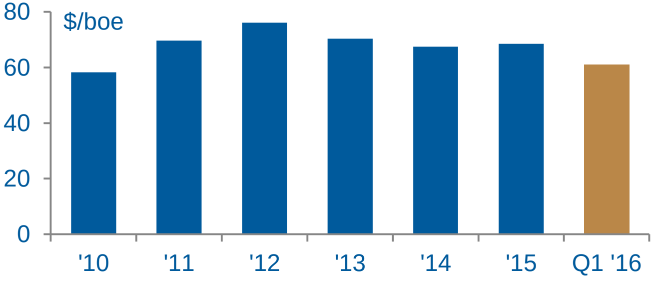
Indonesia

- Madura Strait block
  - BD liquids-rich gas, MDA-MBH, MDK and MAC gas fields
  - Three additional gas discoveries
- Anugerah block exploration



Asia Pacific Operations

Asia Pacific Region Operating Netback[1]

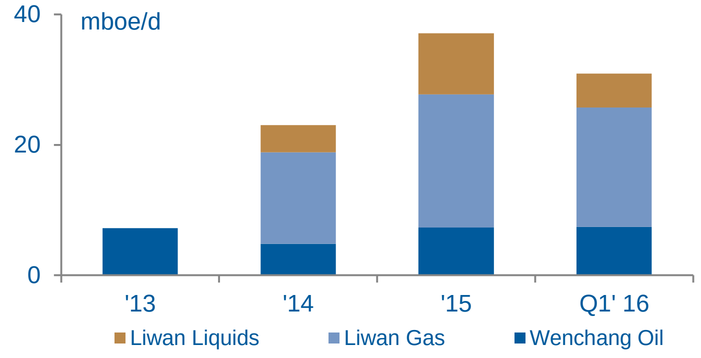


1. Operating netback is a non-GAAP measure. Please see Advisories for details.

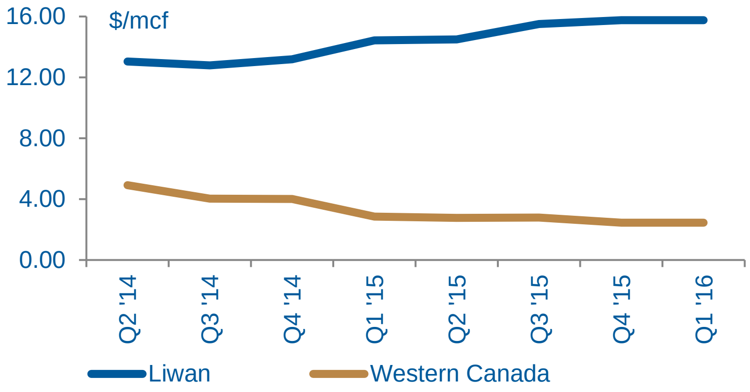
Offshore China

- Liwan Gas Project
  - Liwan 3-1 and Liuhua 34-2 fields on stream
  - Take-or-pay contract
- Liuhua 29-1 gas field ('19)
  - Tie into the existing Liwan infrastructure
  - 8,000 boe/d potential (net)
- Wenchang (light oil)
  - Current production of 7,000 bbls/d (net)
  - Final year of PSC (expires mid '17)

Sales Volumes

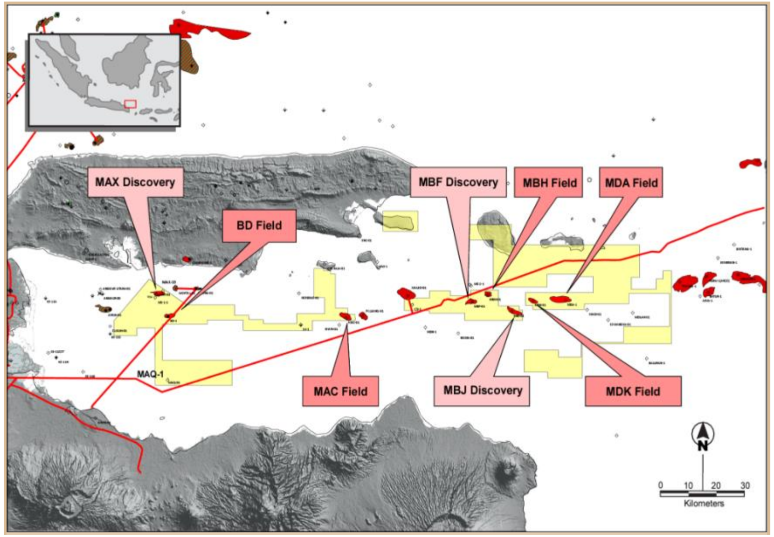


Realized Gas Prices



Indonesia: Madura Strait Developments

- Net production target of 100 mmcf/d ('19)
- Five projects in flight
  - BD liquids-rich gas ('17)
  - MDA-MBH in development phase ('18-'19)
  - MDK in tender phase ('18-'19)
  - MAC plan of development approved
- Additional discoveries (MAX, MBJ, MBF)
- Fixed price contracts, US$6.50-$7.00/mmbtu with annual escalation
- Husky (40%), CNOOC (40%, operator) and Samudra Energy (20%)



Madura Strait

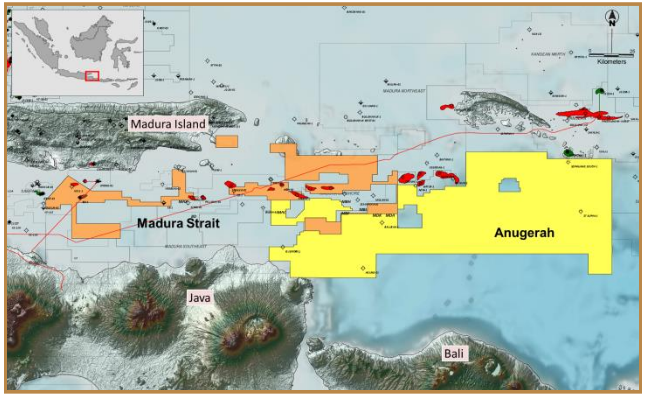
BD Field Nearing Completion

- BD liquids-rich gas field ('17)
  - 40 mmcf/d and 2,400 bbls/d (net)
  - Fixed-price contract of about US$7.00/mmbtu with escalation factors
  - Leased FPSO under construction (~75% complete)
  - Initial four development wells underway
  - Pipeline installation underway
  - Operations planning in progress

BD Field

Asia Pacific Exploration

- Indonesia – Anugerah block
  - 2D/3D seismic acquisition completed
  - Data processing and analysis continue to be evaluated
  - Offset operator set to drill in June
- Taiwan – Deepwater exploration block
  - 10,000 sq. kms
  - Number of significant structures identified
  - Second exploration phase approved
  - Acquire 3D seismic in ’17 timeframe
- Offshore China
  - Block 15/33 shallow water oil exploration
  - Geology similar to Wenchang



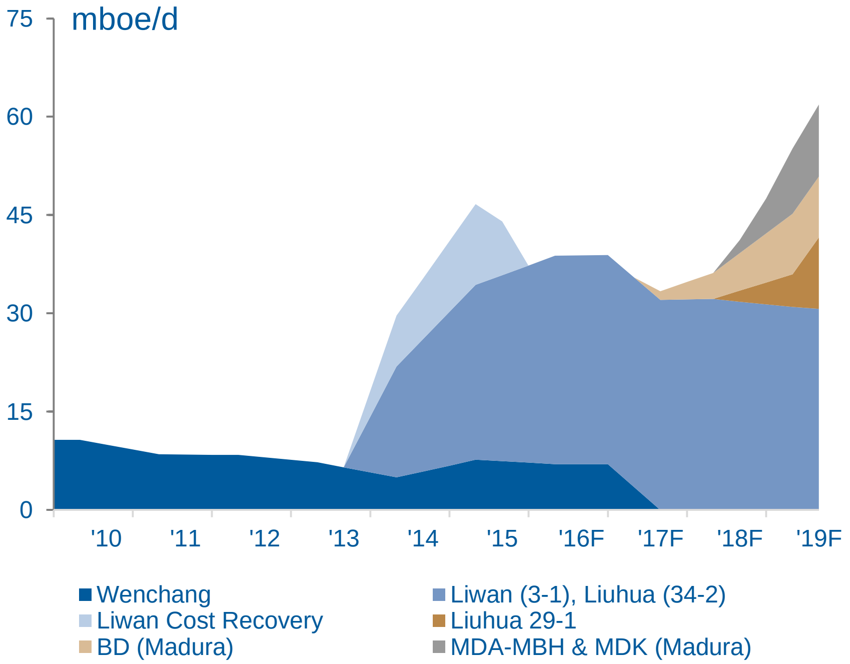
Anugerah Exploration Block

China and Taiwan Exploration Blocks

Future Opportunities in Asia Pacific Region

- Established track record of successful exploration and growth
- Near term growth projects in flight
- Liwan field expansion potential
- Future Madura prospects

Actual and Forecast Production Profile



Atlantic Region
Malcolm Maclean

Maintaining Steady High Netback Production

White Rose (Jeanne d' Arc Basin)

- Cumulative production of 260 million barrels over past 10 years
- Maintaining production through satellite extensions
- Further infill and step-out drilling planned
- Evaluating West White Rose Extension

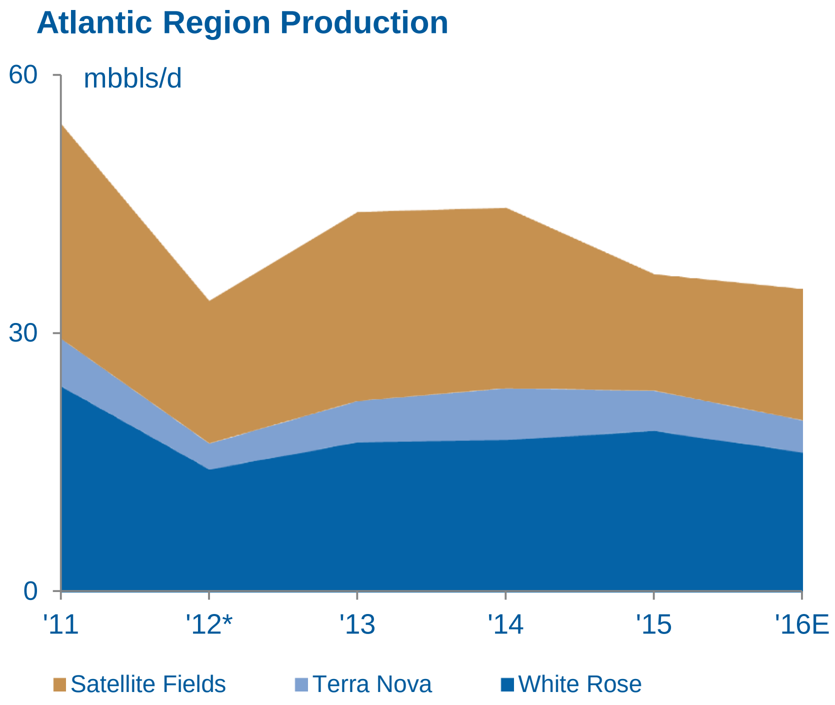
Bay du Nord (Flemish Pass)

- Significant discovery at Bay du Nord
- Long-term development potential of Flemish Pass discoveries

SeaRose FPSO

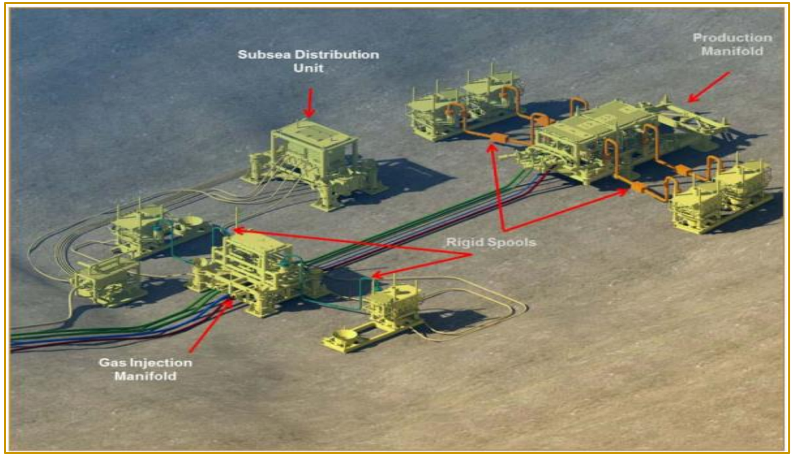
Near Term Satellite Developments Extending Life of Field

- Net production of 40,500 bbls/d (Q1/16)
- North Amethyst Hibernia formation
  - Drilling under way
  - Target net peak production of ~5,000 bbls/d
- South White Rose Extension
  - Two wells on stream
  - Peak net production of ~15,000 bbls/d (*achieved*)
- At least five additional White Rose infill wells planned



Mid Term: West White Rose, Bridge to Flemish Pass

- West White Rose Extension pre-planning
- Two development options under evaluation
    - Wellhead platform
    - Subsea tieback
- SeaRose FPSO tieback
- Potential for new ~40,000 bbls/d (net)



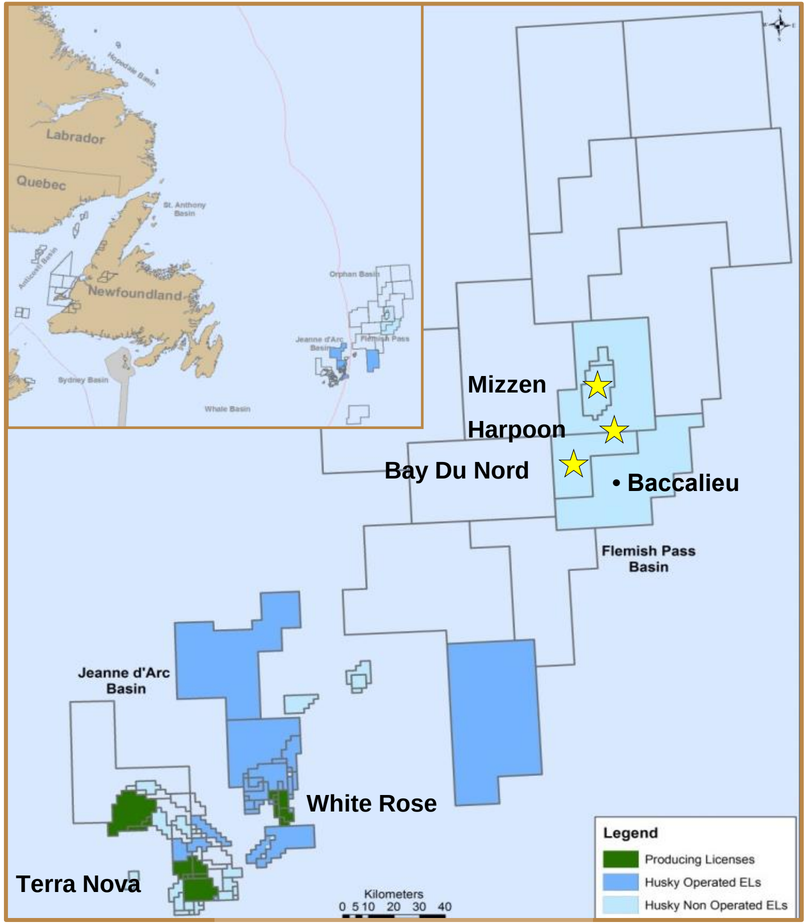
Subsea Tieback

Wellhead Platform

Long Term Opportunities

- Flemish Pass exploration
  - Six wells drilled
  - Appraisal program completed; results being evaluated

- Jeanne d’Arc exploration opportunities under evaluation

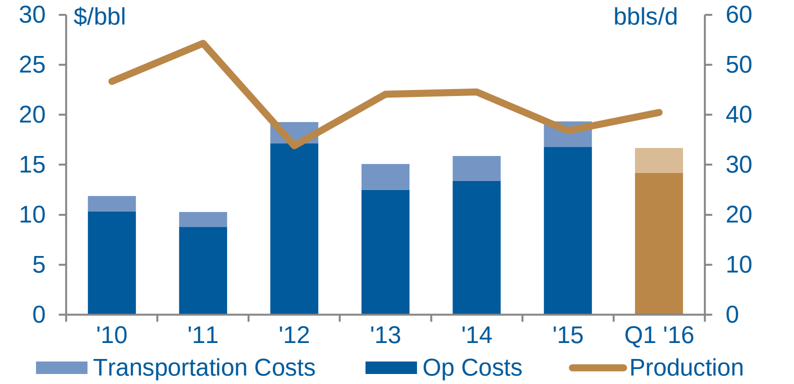


Atlantic Region

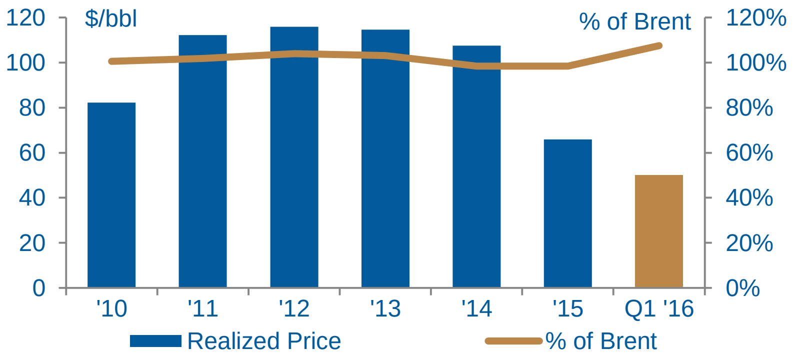
Higher Quality Barrels

- Brent pricing
- Tidewater access
    - Not constrained by North American pipeline issues and domestic supply discounts
- Low operating costs
- Capital-efficient developments through shared infrastructure

Operating Costs



Realized Pricing



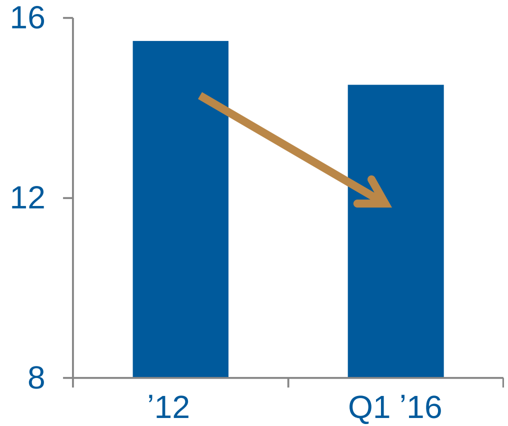
Q&A

Concluding Remarks

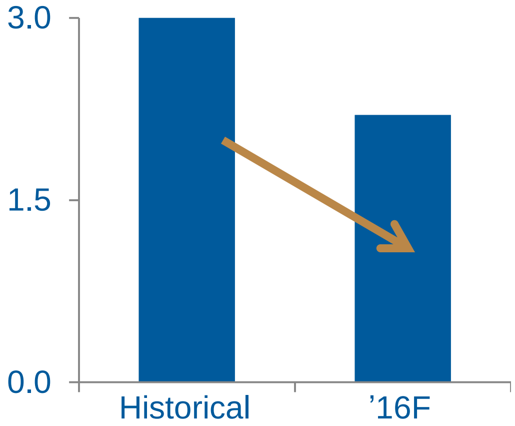
Asim Ghosh

Pathway to Growing Higher Quality Production

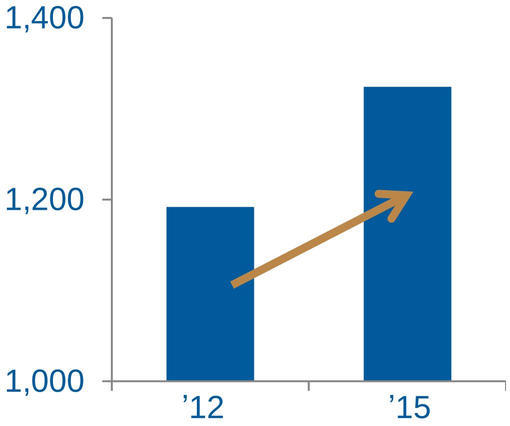
Operating Costs ($/boe)

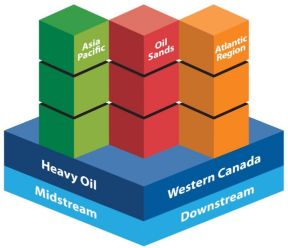


Total Sustaining and Maintenance Capital ($Bn)

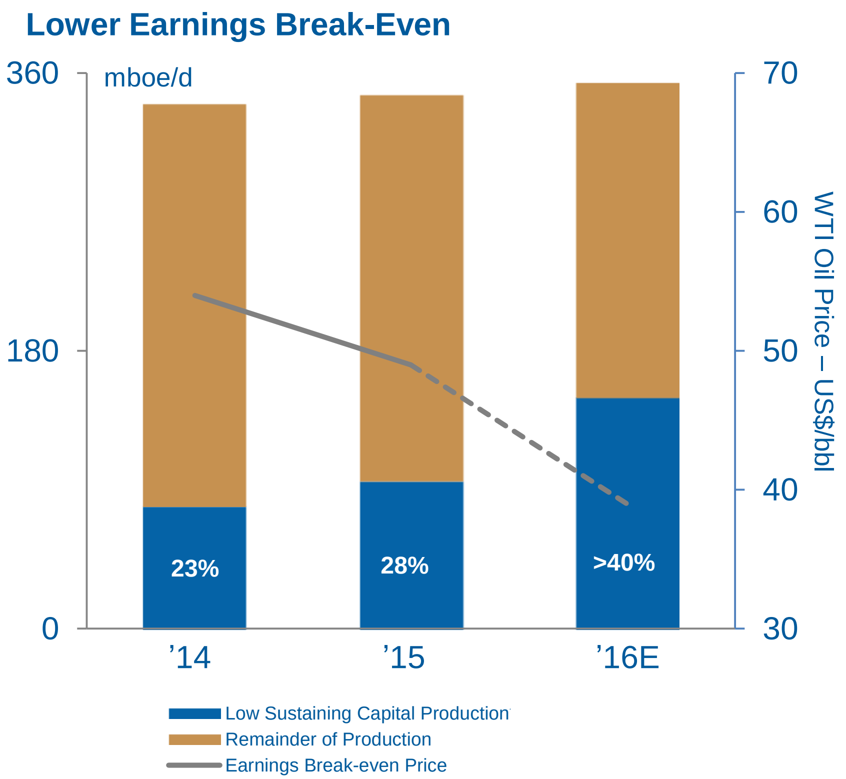


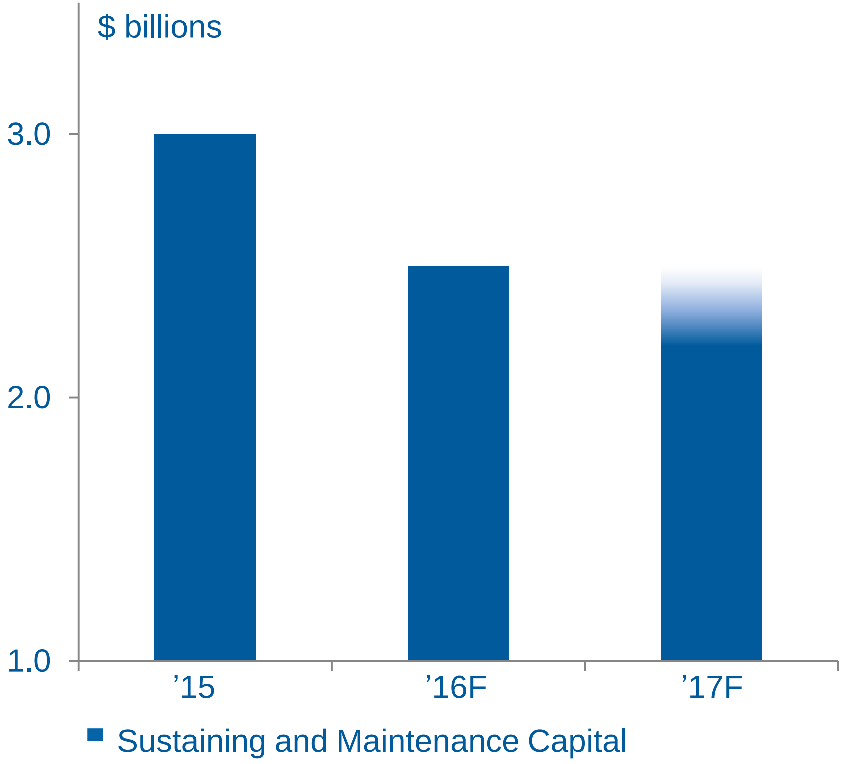
Proved Reserves (mmboe)



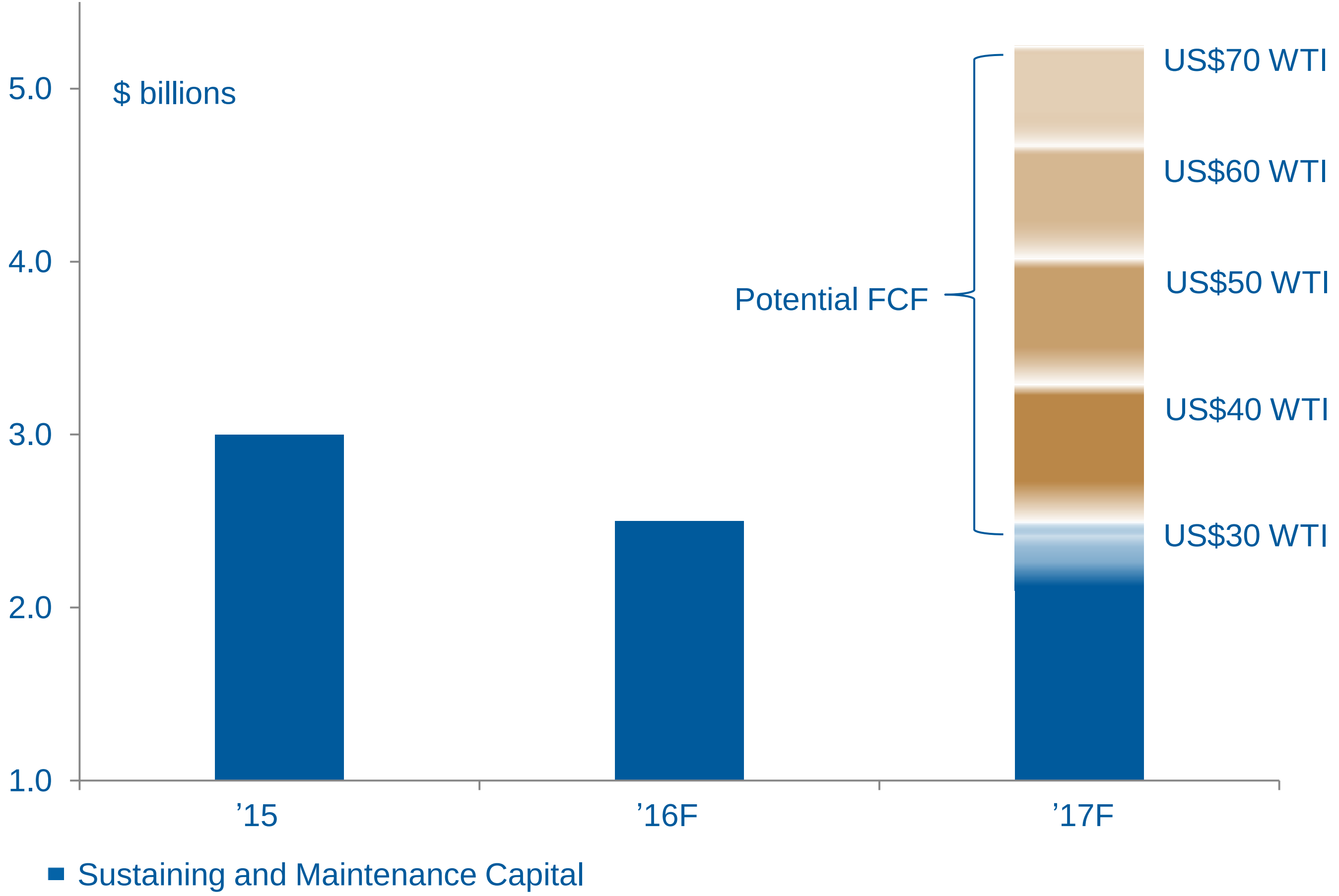


Lowering Break-Even and Sustaining Capital



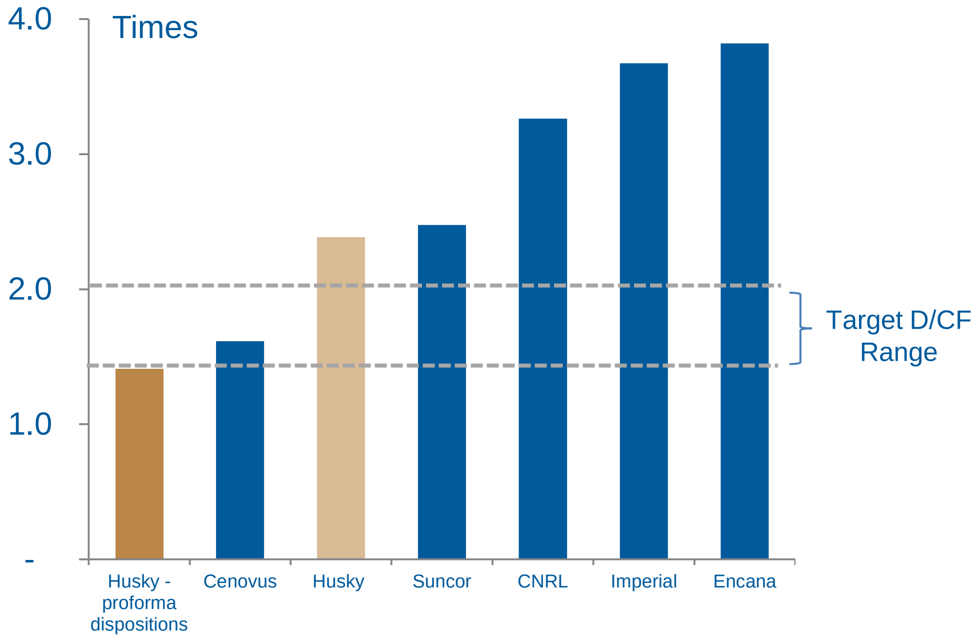


Poised For Free Cash Flow Generation



Clean Bill of Health

Net Debt to Trailing Cash Flow from Operations



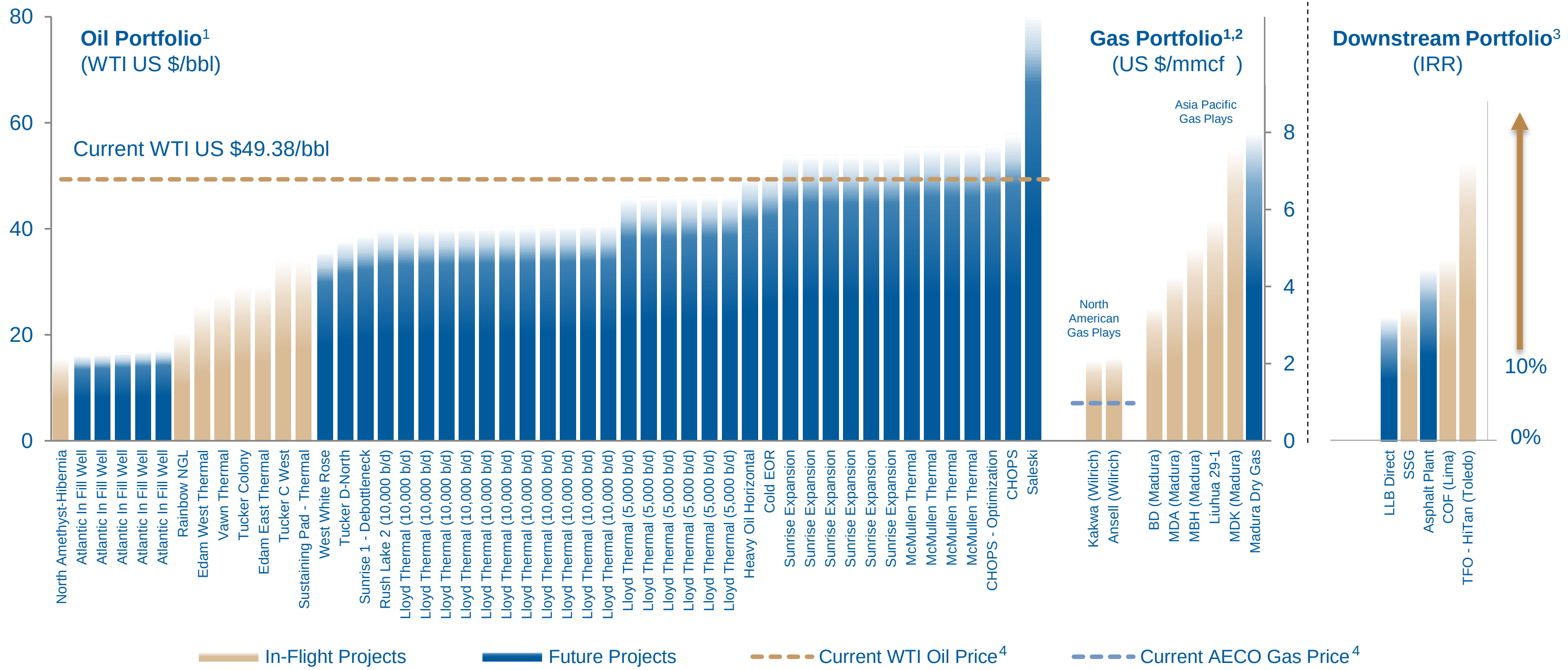
Current Credit Ratings

	Moody's	S&P*	DBRS*
Rating	Baa2	BBB+	A (low)

* Negative outlook

Opportunity Rich . . . Even At Low Prices

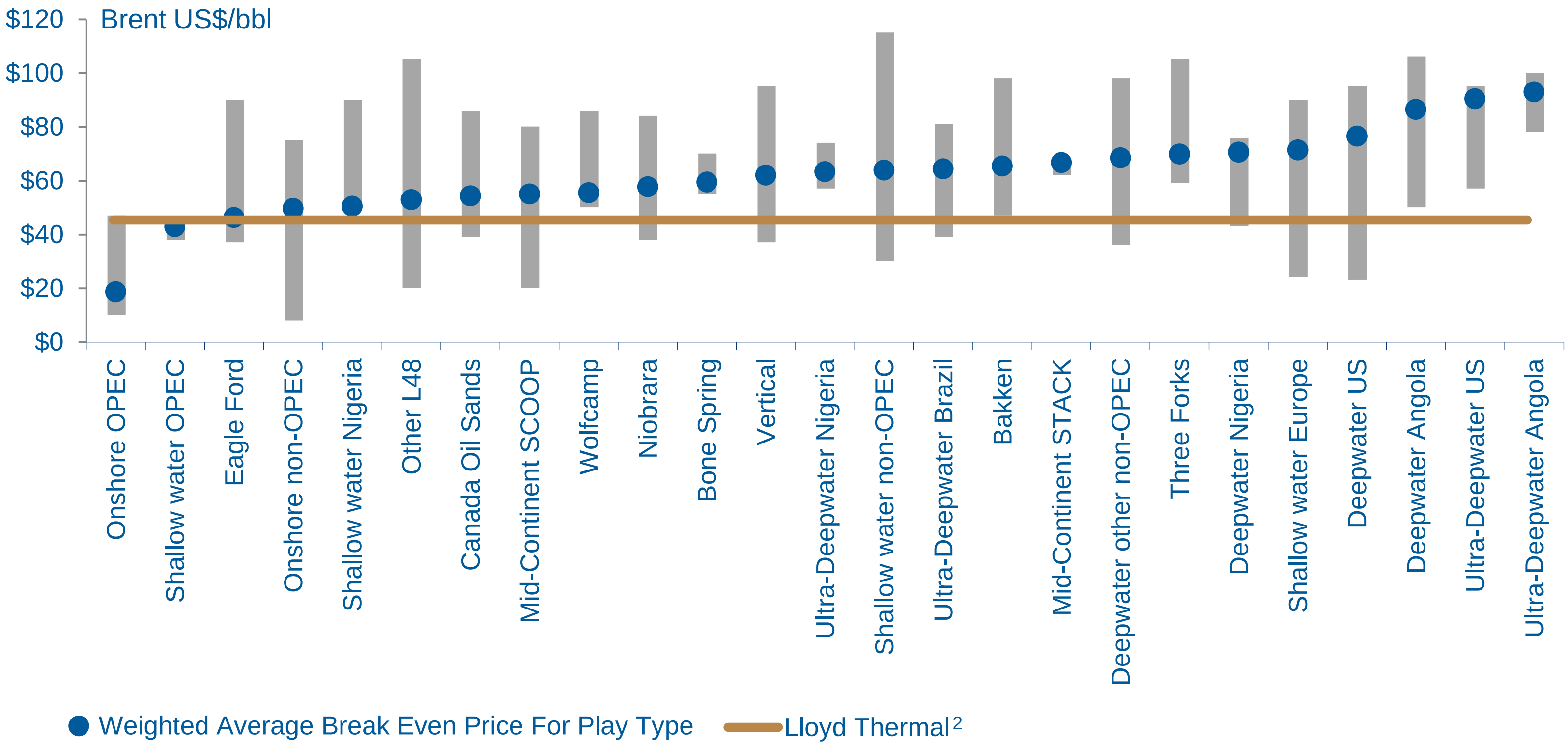
Price Required to Generate 10% IRR



1. Other than as indicated in the Advisories, 10% IRR calculations are based on 2P reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on US$40 WTI price scenario.
3. Downstream portfolio IRR not directly tied to oil or gas price. See Advisories for further detail.
4. WTI and AECO prices as of May 27, 2016. AECO gas price converted to US$ at a CAD/USD 0.75 exchange rate.

Lloyd Thermals – Globally Competitive

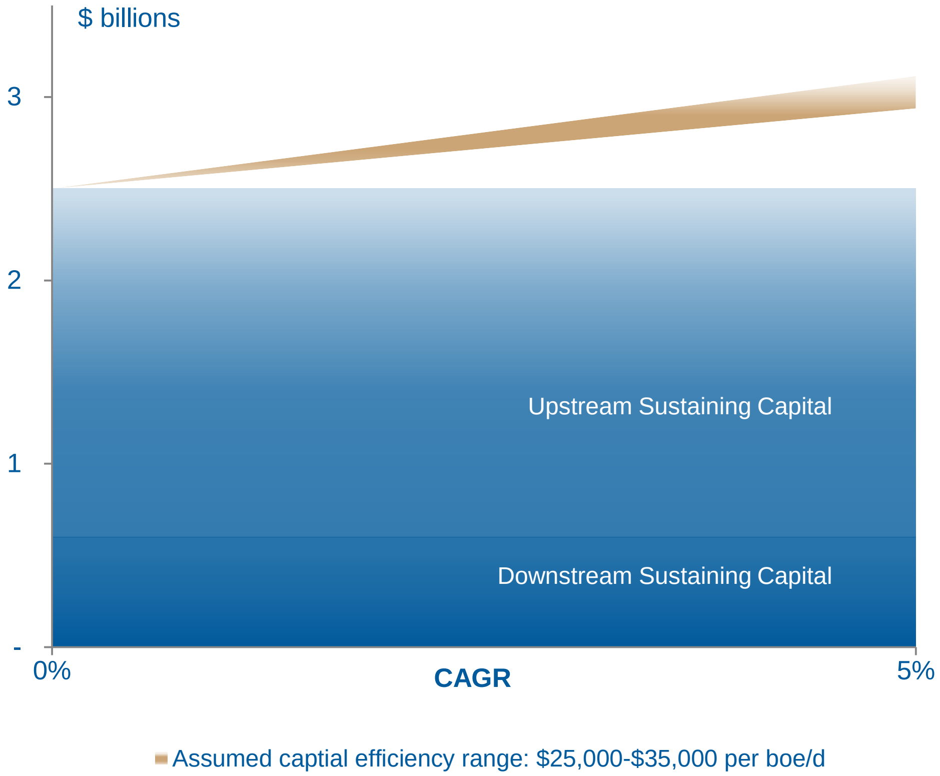
Breakeven at 10% IRR[1]



1. Source: *Pre- FID oil Projects: Global breakeven analysis and cost curves* (Wood Mackenzie Corporate Service), January 2016.
2. Lloyd thermal break-even oil price based on internal estimates.

Capital Efficient Investment Options

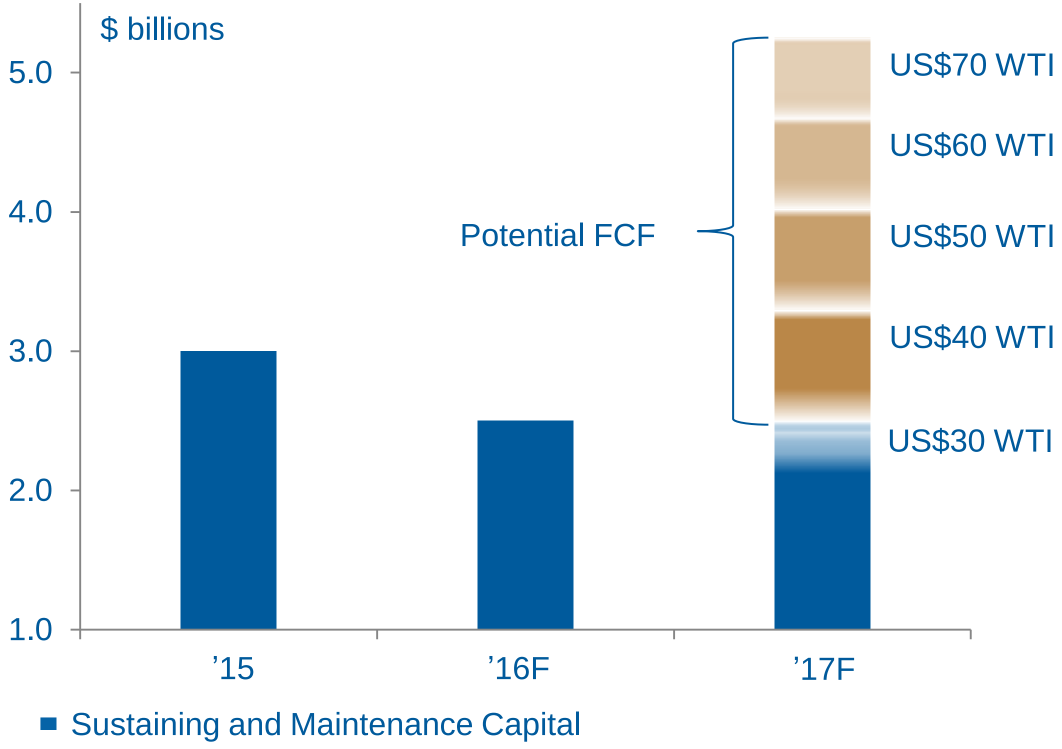
Indicative Growth Capital Profile[1]



1. Illustration based on the following assumptions: 18% annual decline, new production added at $25,000 - 35,000 per bbl/d.

Stronger and More Resilient Business

- Business strategy on course
- Structural changes leading to free cash flow
- Strong balance sheet
- Diverse portfolio of high quality growth projects
- Establish a sustainable cash dividend



Advisories

Forward-Looking Statements

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

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

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; forecasted earnings breakeven for year end 2016; forecasted 2016 exit rate for the Company's low sustaining and maintenance capital production; forecasted sustaining capital costs through 2017; anticipated proportion of total production from low sustaining capital cost projects by year end 2016; forecasted free cash flow generated for range of WTI prices; planned establishment of a sustainable cash dividend; the Company's pro forma net debt and pro forma net debt to trailing cash flow from operations; the Company's 2016 forecasted cumulative procurement savings; targeted net debt ranges, capital expenditures, sustaining and maintenance capital expenditures and production guidance range for 2016; estimated breakdown by region and business segment of forecasted 2016 capital expenditures; estimated breakdown by product type of forecasted 2016 production; projected prices required to generate targeted IRR for the Company's listed in-flight future projects; estimated time to completion for the Company's listed short, mid and long cycle projects; anticipated 2016 year end upstream production mix by product type and region; forecasted production additions from, and 2016 exit rates for, recent low sustaining capital startups; and costs and time frames to develop, and other factors affecting the development of, the Company's contingent resources;

- with respect to the Company's Asia Pacific Region: planned timing of first production at, and targeted daily volumes of production from, the Company's Liuhua 29-1 and BD fields; planned timing of first gas from the Madura Strait MDA-MBH, MDK and MAC POD fields; targeted 2019 combined daily volumes of production from the Madura Strait developments; planned timing of drilling of exploration wells at Block 15/33 offshore China; planned timing of acquiring 3D seismic for the Company's Taiwan deepwater exploration block; and forecasted total daily production through to 2019 for the Company's Asia Pacific Region;

- with respect to the Company's Atlantic Region: forecast net peak daily production from the Company's North Amethyst Hibernia well project; additional planned White Rose infill wells and step-out drilling; forecasted Atlantic Region production exit rate for 2016; and estimated potential increase in daily production with the West White Rose Extension options;

- with respect to the Company's Oil Sands properties: estimated timing fro Sunrise production to be brought back online; and expectation that the Sunrise Energy Project will surpass nameplate capacity;

Forward-Looking Statements continued

- with respect to the Company's Heavy Oil properties: strategic plans and growth strategy for the Company's Lloyd thermals; anticipated net peak daily production for the colony formation; forecasted heavy oil thermal and non-thermal production for year end 2016; forecasted thermal production from Tucker and Lloyd for year-end 2016; anticipated added nameplate capacity by year-end 2016 from the Company's Edam East, Vawn and Edam West thermal projects; anticipated proportion of Heavy oil production from non-thermal and thermal heavy oil production by year-end 2016; forecasted first oil dates and net production rates for the Company's potential future Lloyd thermal projects; the Company's estimated Lloyd thermal breakeven; estimated characteristics of thermal projects;

- with respect to the Company's Western Canadian oil and gas resource plays: the Company's strategic plans for its Western Canada portfolio; the Company's 2016 exit rate for Western Canada production; and the Company's year-end 2016 percentage of Western Canada production made up of resource play production; and

- with respect to the Company's Downstream operating segment: anticipated dates of completion for the Lima crude oil flexibility project and Toledo Hi-TAN project; and the Company's plan to consider expanding the Lloyd asphalt refinery.

Certain information related to industry wells and type curves in this presentation may constitute "analogous information" as defined in NI 51-101. Such information has been obtained from government sources. Management of the Company believes the information is relevant as it helps in making comparisons to industry competitors. The Company is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. Such information is not an estimate of the resources attributable to lands held or to be held by the Company and there is no certainty that the reservoir data, resource estimates, production and decline rates and economics information for the lands held by the Company will be similar to the information presented herein. The reader is cautioned that the data may prove not to be analogous to the lands held by the Company.

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

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

Forward-Looking Statements continued

The Company's Annual Information Form for the year ended December 31, 2015 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

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

The purpose of pro forma net debt and pro forma net debt to trailing cash flow from operations is to provide readers with disclosure of the Company's anticipated net debt upon completion of dispositions listed on slide 14. Readers are cautioned that these estimates may not be appropriate for other purposes.

Non-GAAP Measures

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

- The term "cash flow from operations" is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Cash flow from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation and amortization, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment, unrealized mark to market gains and losses, and other non-cash items.

Non-GAAP Measures continued

The following table shows the reconciliation of cash flow – operating activities to cash flow from operations for the three months ended March 31, 2016 and the previous five years:

Cash Flow from Operations

($ millions)		Q1 2016	2015	2014	2013	2012	2011
GAAP	Net earnings (loss)	(458)	(3,850)	1,258	1,829	2,022	2,224
	Items not affecting cash:						
	Accretion	34	121	134	125	97	79
	Depletion, depreciation and amortization	722	8,644	4,010	3,005	2,580	2,519
	Inventory w rite-dow n to net realizable value	-	22	211	-	-	-
	Exploration and evaluation expenses	-	242	6	10	60	68
	Deferred income taxes	(7)	(1,827)	(191)	210	278	562
	Foreign exchange	1	27	71	11	(20)	14
	Stock-based compensation	17	(39)	(17)	105	54	(1)
	Loss/(gain) on sale of assets	2	(16)	(36)	(27)	1	(261)
	Unrealized mark to market	123	(14)	79	(11)	(50)	(8)
	Other	-	19	10	(35)	(12)	2
Non-GAAP	**Cash flow from operations**	434	3,329	5,535	5,222	5,010	5,198

- Free Cash Flow is a non-GAAP measure, which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Free cash flow is presented in this presentation to assist management and investors in analyzing operating performance by business in the stated period. Free cash flow equals net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation and amortization, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment, unrealized mark to market gains and losses, and other non-cash items less capital expenditures

The following table shows the reconciliation of free cash flow – operating activities to cash flow from operations for the three months ended March 31, 2016 and the previous five years:

Free Cash Flow

($ millions)		Q1 2016	2015	2014	2013	2012	2011
GAAP	Net earnings (loss)	(458)	(3,850)	1,258	1,829	2,022	2,224
	Items not affecting cash:						
	Accretion	34	121	134	125	97	79
	Depletion, depreciation and amortization	722	8,644	4,010	3,005	2,580	2,519
	Inventory w rite-dow n to net realizable value	-	22	211	-	-	-
	Exploration and evaluation expenses	-	242	6	10	60	68
	Deferred income taxes	(7)	(1,827)	(191)	210	278	562
	Foreign exchange	1	27	71	11	(20)	14
	Stock-based compensation	17	(39)	(17)	105	54	(1)
	Loss/(gain) on sale of assets	2	(16)	(36)	(27)	1	(261)
	Unrealized mark to market	123	(14)	79	(11)	(50)	(8)
	Other	-	19	10	(35)	(12)	2
	Capital expenditures	(410)	(3,005)	(5,023)	(5,028)	(4,701)	(4,800)
Non-GAAP	**Free cash flow**	**24**	**324**	**512**	**194**	**309**	**398**

Advisories

- Net Debt to Cash Flow from operations is a non-GAAP measures that equals total debt less cash and cash equivalents divided by cash flow from operations. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt.

- EBITDA is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFS, as an indication of performance. EBITDA is presented in this presentation to assist management and investors in analyzing operating performance by business in the stated period. EBITDA equals net earnings (loss) plus finance expenses (income), provisions for (recovery of) income taxes, and depletion, depreciation and amortization.

- Operating netback is a common non-GAAP metric used in the oil and gas industry. This measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. The operating netback was determined as realized price less royalties, operating costs and transportation on a per unit basis.

Disclosure of Oil and Gas Information

Unless otherwise stated, reserve and resource estimates in this presentation, have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have an effective date of December 31, 2015 and represent Husky's share. Unless otherwise noted, projected and historical production numbers given represent Husky's share. Unless otherwise noted, historical production numbers are for the year ended December 31, 2015.

Certain information related to industry wells in this presentation may constitute "analogous information" as defined in NI 51-101. Such information has been obtained from government sources. Management of the Company believes the information is relevant as it helps in making comparisons to industry competitors. The Company is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. Such information is not an estimate of the resources attributable to lands held or to be held by the Company and there is no certainty that the reservoir data, resource estimates, production and decline rates and economics information for the lands held by the Company will be similar to the information presented herein. The reader is cautioned that the data may prove not to be analogous to the lands held by the Company.

Husky's Lloydminster Heavy Oil and Gas thermal bitumen unrisked best estimate contingent resources consist of 250 million barrels of economic development pending contingent resources and 570 million barrels of economic status undetermined development unclarified contingent resources. The figures represent Husky's working interest volumes. The development pending category consists of seven steam assisted gravity drainage (SAGD) projects and one combined SAGD and cyclic steam stimulation (CSS) project that have been scheduled for initial production starting in 2019 through to 2024. The first two projects have a total capital cost to first production of $800 million based upon the pre-development studies. The economic status undetermined development unclarified projects require additional technical and commercial analysis of the conceptual SAGD or CSS studies. Of these, the first project requires $0.4 billion to achieve commercial production in 2030. The remaining projects are to be developed over more than 50 years in accordance with the conceptual studies for this large resource. In total, 220 million barrels of heavy crude oil are based upon pre-development studies while an additional 600 million barrels of heavy crude oil are based upon conceptual plans. Specific contingencies preventing the classification of contingent resources at the Company's Lloydminster Heavy Oil thermal contingent resources as reserves include the need for further reservoir studies, delineation drilling, verification of sub-zone continuity and quality that would enable feasible implementation of a thermal scheme, the formulation of concrete development plans and facility designs to pursue development of the large inventory of opportunities, the Company's capital commitment, development over a time frame much greater than the reserve timing window and regulatory applications and approvals. Positive and negative factors relevant to the contingent resource estimates include potential reservoir heterogeneity in sub-zones which may limit the applicability of thermal schemes, a higher level of uncertainty in the estimates as a result of lower drilling density in some projects and current lack of development plans in the unclarified contingent resources. The main risks are the low well density and the associated geological uncertainties in certain projects, the production performance and recovery long term, future commodity prices and the capital costs associated with wells and facilities planned over an extended future period of time.

Advisories

McMullen contains unrisked best estimate economic development pending contingent resources of 44 million barrels of bitumen for Phase 1 of the development with a further 1.3 billion barrels of bitumen of unrisked best estimate economic status undetermined development unclarified contingent resources. McMullen is a thermal play in the Wabiskaw formation covering over 130 sections southwest of Wabasca. Husky has a working interest of 100 percent. The cost to first production for Phase 1, based upon the pre-development study, is approximately $512 million for the initial commercial demonstration facility and horizontal cyclic steam stimulation (HCSS) wells in 2025. The subsequent phases are based upon a conceptual development plan at this time and each has the same capital estimate with initial production scheduled for 2030 for Phase 2. The remaining commercial facilities and wells will be developed over more than 50 years in accordance with the conceptual study for this large resource. The development of these projects depends on the results of the technical analysis, future heavy oil prices and the Company's commitment to dedicate capital to this large inventory of projects. Specific contingencies preventing the classification of contingent resources at the McMullen thermal development project as reserves include the need for further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and approvals and Company approvals. Positive and negative factors relevant to the estimates of these resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density. The main risks are the low well density and the associated geological uncertainties, the production performance and recovery long term and the capital costs associated with wells and facilities planned over an extended future period of time.

Saleski contains unrisked best estimate economic development on hold contingent resources of 10 billion barrels of bitumen in the Grosmont formation. Saleski is located north of Wabasca. Husky has a working interest of 100 percent. Based on a pre-development study it is estimated that a total cost of approximately $825 million would be required to develop the initial commercial facility and corresponding HCSS wells with first production scheduled in 2025. Due to the large extent of the resource, staged development of additional facilities and wells are included in the pre-development study and extend the overall estimated production life beyond 50 years. The development is on hold due to low bitumen prices and future development will depend on prices and the Company's commitment to dedicate capital to this project. Specific contingencies preventing the classification of contingent resources at the Saleski oil sands project as reserves include the need for further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and Company approvals. Positive and negative factors relevant to the estimate of contingent resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density. The main risks are the low well density and the associated geological uncertainties, the production performance and long term recovery and the capital costs associated with wells and facilities planned over an extended future period of time.

The Ansell liquids-rich natural gas resource play is located in the deep basin Cretaceous formations of west-central Alberta, and Husky has an average 92 percent working interest. Husky is actively developing Ansell. This producing property contains unrisked best estimate economic development pending contingent resources of 400 million barrels of oil equivalent, comprised of 2.2 tcf of natural gas and 48 million barrels of NGL. The initial contingent resource fracture stimulated horizontal wells are scheduled to be drilled starting in 2023, following the development of the proved and probable reserves. The cost to achieve initial commercial production is the cost of the first well of $7 million. The remaining wells (approximately 500 working interest wells) will be drilled over the next 10 to 20 years in accordance with the pre-development study for the resource play. Specific contingencies preventing the classification of contingent resources in the Ansell liquids-rich resource play as reserves include the timing of development which is outside the timing allowed for booking as reserves and final Company approvals of capital expenditures. Positive and negative factors relevant to the estimate of Ansell contingent resources include a lower level of uncertainty in the estimates as a result of the large number of producing wells, extensive production history from the property, Husky's large contiguous land base and Husky's ownership of existing infrastructure in the area. Key risks include the performance of future wells when the play is expanded and reducing costs to achieve optimal results in a low gas and natural gas liquids price environment.

Advisories

Liuhua 29-1, located in the South China Sea approximately 300 km southeast of the Hong Kong Special Administrative Region, contains unrisked best estimate economic development pending contingent resources of 28 million barrels of oil equivalent, comprised of 139 Bcf of natural gas and 5 million barrels of condensate. Husky has a working interest of 49 percent. The project uses conventional offshore gas wells and will be connected to the producing Liwan gas field. Based on the pre-development study, the cost to first production to complete and tie-in the well is approximately $617 million with an on-stream date in 2019. The development of this project depends on the Company's and partners commitment to dedicate capital to this project. Specific contingencies preventing the classification of contingent resources for Liuhua 29-1 are the signing of a Gas Sales Agreement and regulatory approvals. Positive and negative factors relevant to the estimates of these resources include a higher level of certainty in the estimates as a result of extensive appraisal drilling and testing. The main risk is the production performance and recovery long term.

Madura Strait, located offshore East Java, south of Madura Island, Indonesia, contains unrisked best estimate economic development pending contingent resources of 11 million barrels of oil equivalent, comprised of 62 Bcf of natural gas and 0.4 million barrels of condensate. Husky has a working interest of 40 percent. The project uses conventional offshore gas wells and will be connected the infrastructure currently under construction for the pools booked as reserves. First production associated with the reserves in the Madura Strait Block is anticipated in 2017. The pre-development study for the contingent resources has first production commencing in 2019 at a cost of $124 mm. The development of this project depends on the Company's and partners commitment to dedicate capital to this project. Specific contingencies preventing the classification of contingent resources for Madura Contingent Resources are the signing of a Gas Sales Agreement and regulatory approvals. Positive and negative factors relevant to the estimates of these resources include the development in conjunction with the reserves properties in the field and the reliance on volumetric estimates. The main risks include obtaining all approvals and the production performance and recovery long term.

Husky's Lloydminster Heavy Oil cold heavy oil production with sand (CHOPs) and Horizontal well opportunity includes 166 million barrels (Husky's working interest) of unrisked economic best estimate contingent resources in the development pending sub-class and a further 593 million barrels (Husky's working interest) of unrisked best estimate contingent resources in the development unclarified sub-class with the economic status undetermined. A typical CHOPS well has a cost estimate to drill, complete and equip of $588,000 while a 5 well horizontal pad has a cost estimate of $7.1 million with the first developments online in 2026 based on a pre-development study. This is a continuation of the CHOPs and horizontal well development programs which have been proven to be successful in the Lloydminster area. The timing of development and company approvals are the main contingencies preventing the booking of these volumes as reserves. Positive and negative factors relevant to these contingent resources include a lower level of uncertainty in the estimates as a result of the large number of producing wells, extensive production history from the property, Husky's large contiguous land base and Husky's ownership of existing infrastructure in the area. The key risk is the execution of a multi-year program and reducing capital and operating costs in a low heavy oil price environment.

Heavy Oil Cold EOR, located in the Lloydminster area, contains 231 million barrels (Husky's working interest) of unrisked economic best estimate contingent resources in the development unclarified sub-class. Cold EOR Solvent Injection is a cyclic process utilizing CO_2 which has been demonstrated to be technically successful in the area. The wells and area have been identified in the conceptual development study but more detailed development plans are required for each field. The first phase of the projects is planned for 2021 with a capital cost of $207 million to reach first oil production in one of the identified fields. The timing of development, regulatory and company approvals are the specific contingencies preventing the booking of these volumes as reserves as well as the need for additional assessment for the area where the economic status is undetermined. Positive and negative factors include the extensive land base and infrastructure while the ultimate recovery for this technology is still being evaluated in the field. Key risks include the range of uncertainty in the ultimate recovery and accessing a long term supply of CO_2 for the projects.

There is uncertainty that it will be commercially viable to produce any portion of the resources (referred to in the above paragraphs).

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The Company uses the terms barrels of oil equivalent ("boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not represent value equivalency at the wellhead.

In this presentation, the Company uses the term operating costs per barrel, which is consistent with other oil and gas producer's disclosures, and is calculated by dividing total operating costs for the Company's Heavy Oil thermal or non-thermal production, as applicable, by the total barrels of such thermal or non-thermal production, as applicable. The term is used to express operating costs on a per barrel basis that can be used for comparisons.

Sustaining Cost per barrel is the additional capital that is required by the business to maintain production and operations at existing levels on a per unit basis. It is calculated as annual capital expenditures divided by plant design throughput. This term does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

IRR calculations shown reflect a net present value of $0 using a 10% discount rate applied to before tax cash flows. The calculation is based on holding several variables constant throughout the period, including: estimated WTI oil price per barrel priced in US dollars, foreign exchange rate, light-heavy oil differentials, realized refining margins, forecast utilization of downstream facilities, estimated production levels, and other factors consistent with normal oil and gas company operations. This measurement is used to assess potential return generated from investment opportunities and could impact future investment decisions. This measure does not have any standardized meaning and should not be used to make comparisons to similar measures presented by other issuers.

Steam-oil ratio ("SOR") measures the average volume of steam required to produce a barrel of oil. Water-oil ratio ("WOR") measures the average volume of water produced per a barrel of oil. These measures do not have any standardized meanings and should not be used to make comparisons to similar measures presented by other issuers.

Normalized bitumen production rates included on slide 32 are the rates of the other listed projects with their operating characteristics adjusted to resemble the Sunrise conditions. Factors that are adjusted include: pay thickness (adjusted to 31.5 meters), operating pressure (adjusted to 1.750 kPag), and well length (adjusted to 800 meters). This measure does not have any standardized meaning and should not be used to make comparisons to similar measures presented by other issuers.

Earnings break-even reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate a net income of CAD $0 in the 12 month period ending December 31, 2016. This assumption is based on holding several variables constant throughout the period, including: foreign exchange rate, light-heavy oil differentials, realized refining margins, forecast utilization of downstream facilities, estimated production levels, and other factors consistent with normal oil and gas company operations. This measurement is used to assess the impact of changes in WTI oil prices to the net earnings of the Company and could impact future investment decisions.

Note to U.S. Readers

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, "Standards of Disclosure for Oil and Gas Disclosure", adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.

All currency is expressed in Canadian dollars unless otherwise directed.