2017 Corporate Guidance
December 13, 2016

Husky Energy

Strong Vitals in Place to Grow Higher Return Production

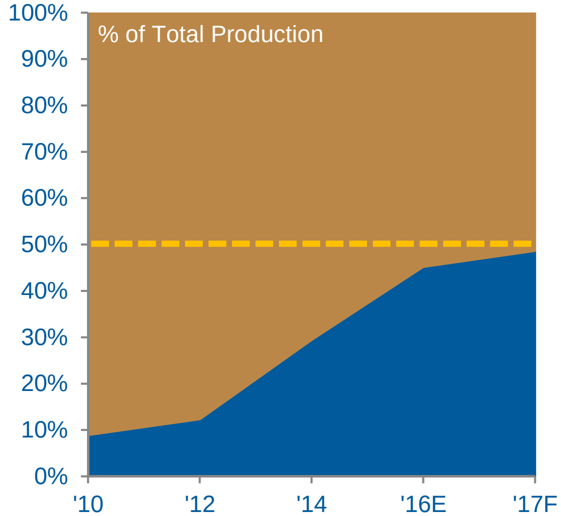
Strategy On Course (2010 - 2016)

- Decision to remain diversified and integrated
- Focus on low sustaining capital projects
  - Growth to over 40% of total production
  - Thermal operations, Asia Pac natural gas
- Completed major projects
  - Liwan (offshore China), Sunrise (Oil Sands)
  - 5 x Lloyd thermals and Tucker expansion
- Lowered cost structure
  - Sustaining and maintenance capital reduced by ~30% from historical levels
  - Operating costs reduced by ~20% from 2014
- Strengthened balance sheet
  - Net debt < 2x Cash flow from operations

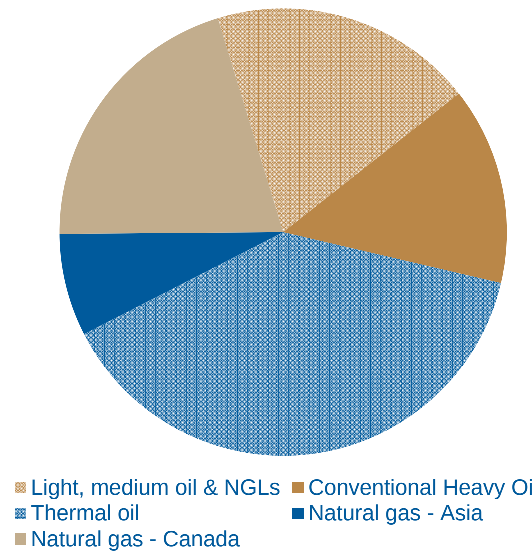
2017+

- Maintain balance sheet strength
- Drive growth of higher return production
- Continue to lower cost structure
- Grow free cash flow

Improving Production Base

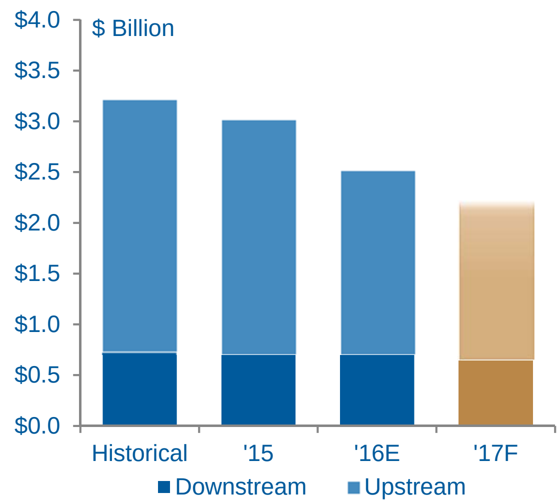


Diversified Production Mix ('17E)

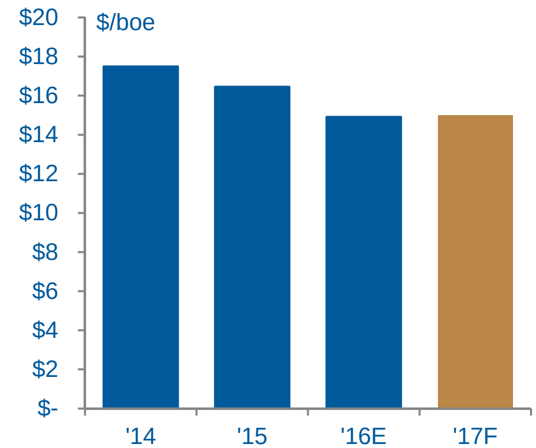


Improving Cost Structure

Annual sustaining and maintenance capital [2]



Lowering Upstream Operating Costs

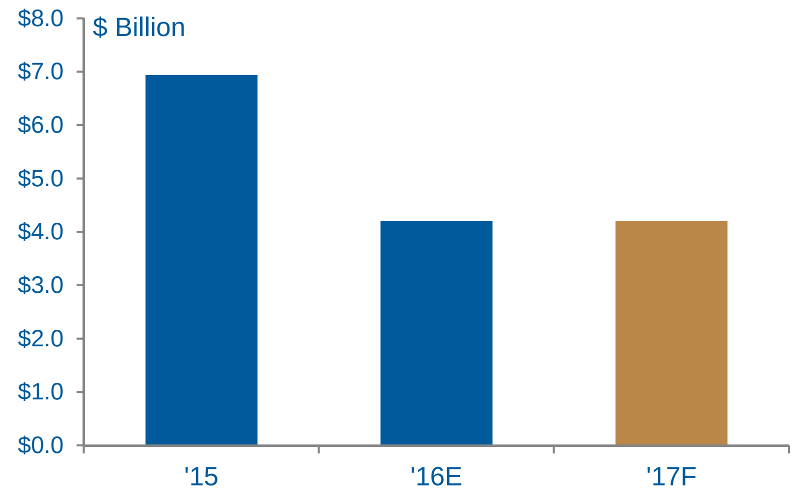


1. *Low sustaining capital production, as referred to throughout this presentation includes production from Tucker, Thermal, Oil Sands and Asia Pacific natural gas.*
2. *Sustaining and maintenance capital, net debt, cash flow from operations and free cash flow*, as referred to throughout this presentation, are non-GAAP measures. Please see Advisories for further detail.

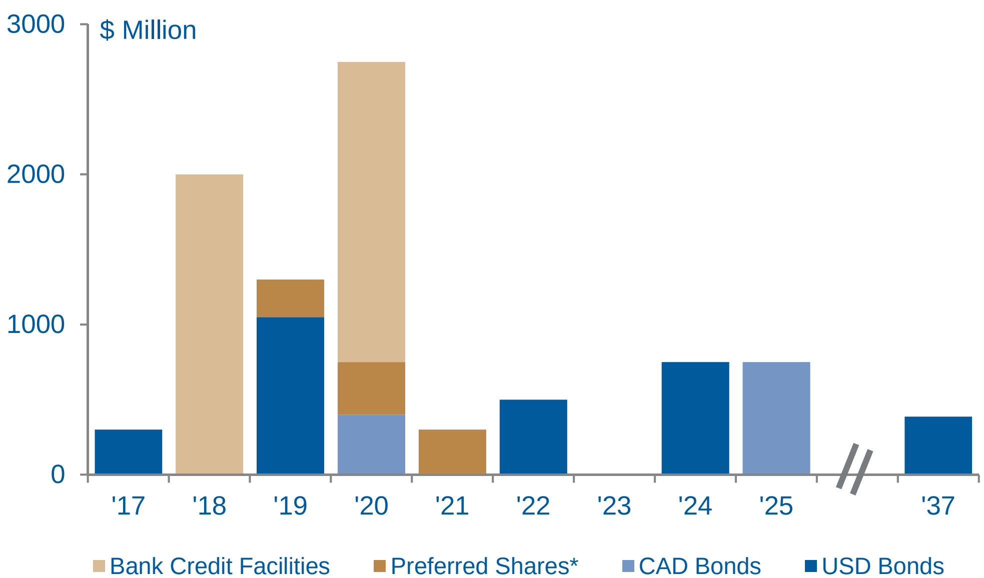
Strong Balance Sheet

- Net debt of $4.1 billion
  - $1.4 billion cash on hand
- $4 billion in undrawn banks lines
- Maintaining strong investment grade credit rating
  - Moody's – Baa2
  - S&P – BBB+ (Stable)
  - DBRS – A (low)
- No major long-term bond maturities until 2019

Net Debt[1]

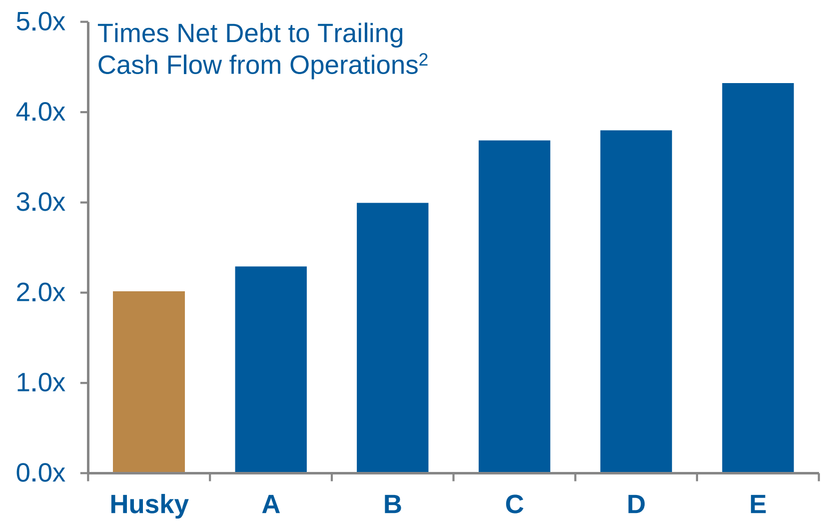


Debt Maturity Schedule



* Husky has redemption option.

Comparable Debt Metrics[1]



1. Peers include Cenovus, CNRL, Encana, Imperial, Suncor. Peer data sourced from public filings available on SEDAR as of September 30, 2016.
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 September 30, 2016. Please see Advisories for further detail.

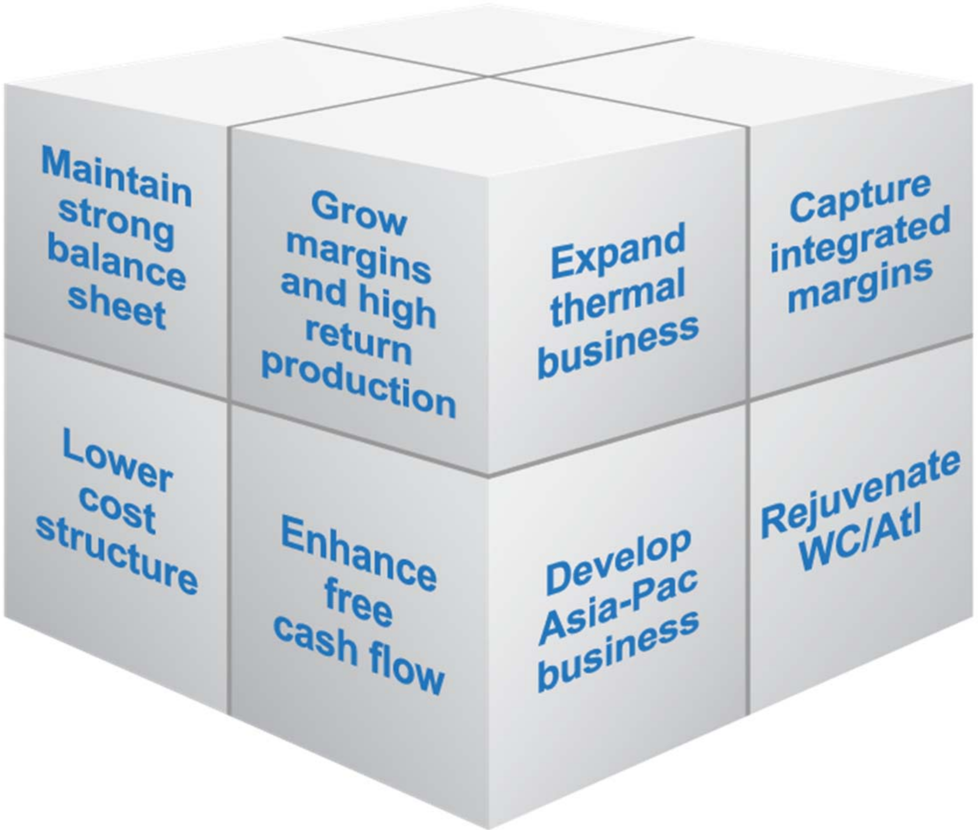
2017 Key Deliverables

Strategic Objectives

- Maintain balance sheet strength
- Growth of higher return production
- Continue to lower cost structure
- Free cash flow generation

Operational Objectives

- Thermal Growth
  - Lloyd and Tucker growth and Sunrise ramp-up
- Further develop integrated value chains
  - Lloyd Upgrader, Lima Crude Oil Flexibility
  - Assess asphalt expansion
- Grow fixed-price Asia Pacific business
  - First gas at Indonesia BD field
  - Advance four additional fields
- Stabilize production in Western Canada & Atlantic Regions
  - Western Canada resource play drilling
  - Atlantic Region infill drilling
  - Assess West White Rose



2017 Guidance

Capital Spending **$2.6 - $2.7 Billion**

Upstream:	$1.7 – $1.8 billion
Downstream:	$0.7 – $0.8 billion
Corporate:	$0.1 billion

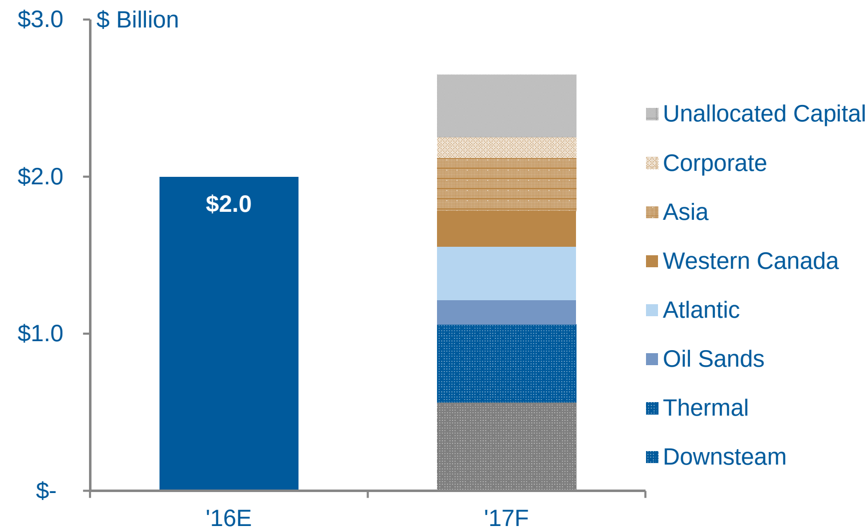
- Sustaining and maintenance capital $2.2-$2.3 billion

Upstream:	$1.6 billion
Downstream:	$0.7 billion

Upstream Production

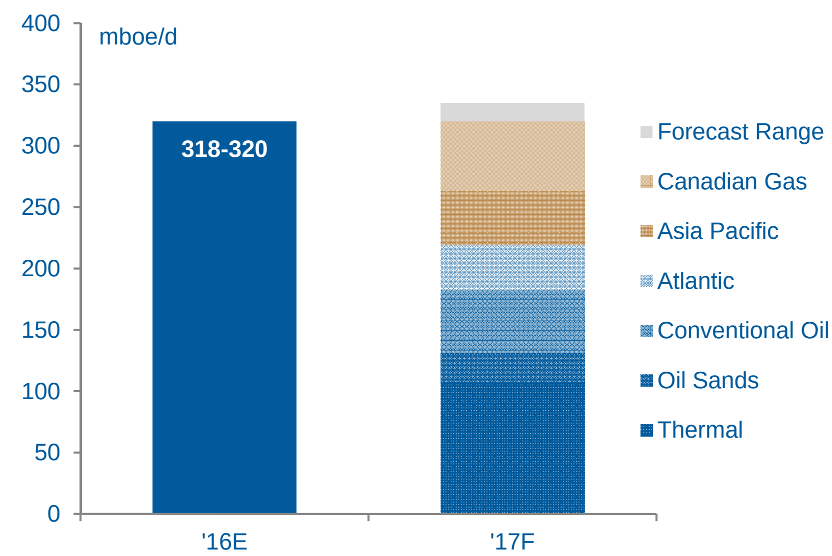
- Annual average production forecast 320,000 – 335,000 mboe/d
  - Total production growth of up to 5%
  - Thermal operations growth of >25%
  - ~ 45,000 boe/d new high return production

Capex: $2.6 - 2.7 Billion[1]



1. Excludes asset retirement obligations and capitalized interest.

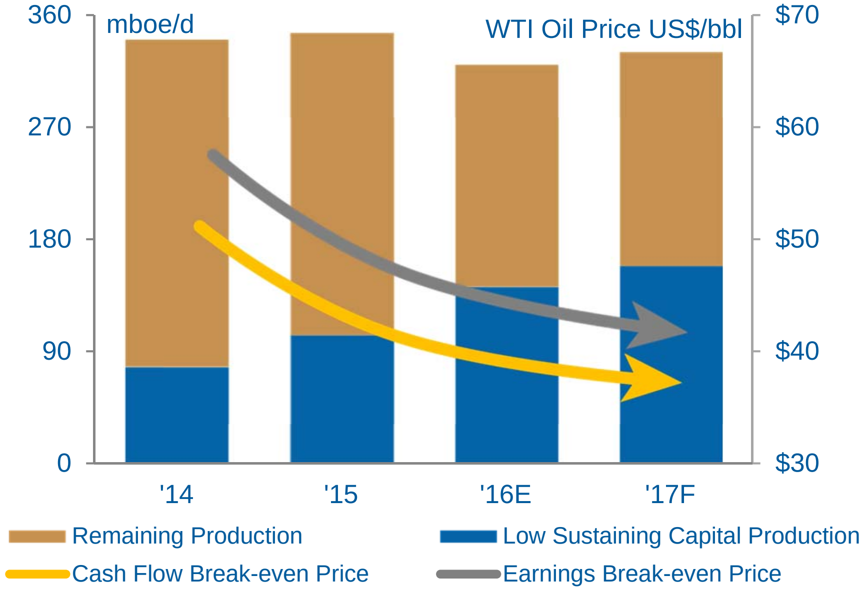
Production Range: 320,000 - 335,000 boe/d



Pathway To Free Cash Flow

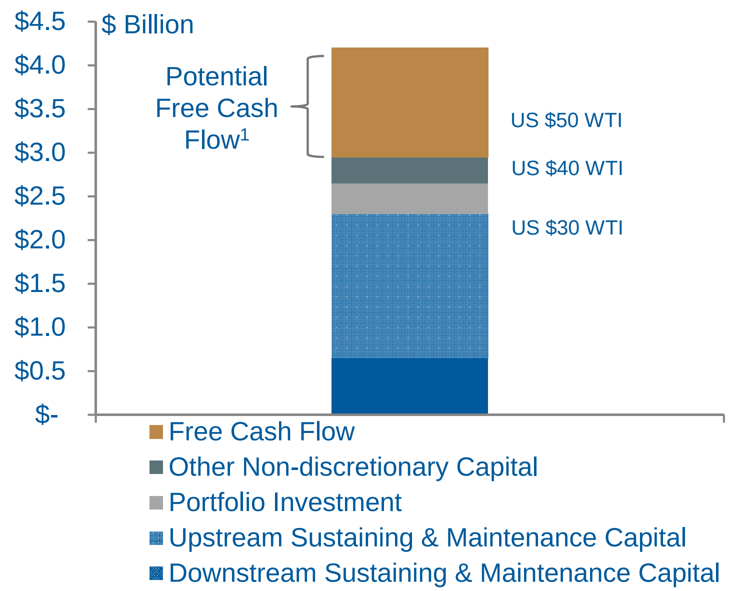
- Improving quality of cash flow from operations
  - Lower cash costs → increased margins across portfolio
  - Reduced oil price volatility
    - Downstream integration
    - Fixed-price gas contracts
- Focus on higher return production
- Lowering earnings and cash flow from operations break-even points
- Free cash flow generation

Lowering Break-Even Prices[1]



1. Cash flow break-even and earnings break-even prices, as referred to through out this presentation, have the meanings set out in the Advisories.

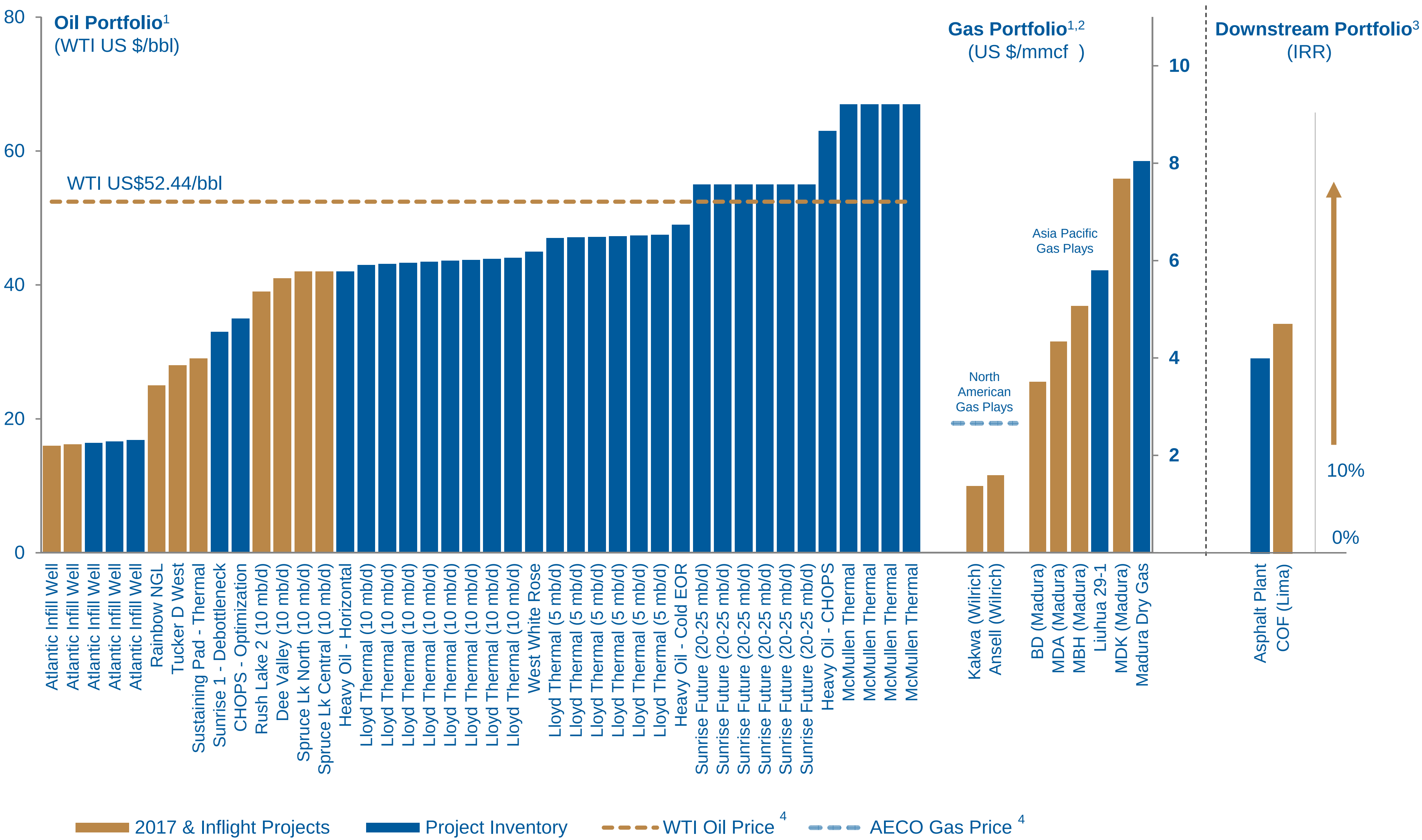
2017 Free Cash Flow Generation



1. *Potential free cash flow based on WTI price of US$48 per barrel, CAD$2.50 AECO gas price, 0.76 CAD/CAD exchange rate, US$16 Chicago 3-2-1 crack spread.*

Robust Portfolio Of High Quality, High Return Projects

Price Required to Generate 10% IRR



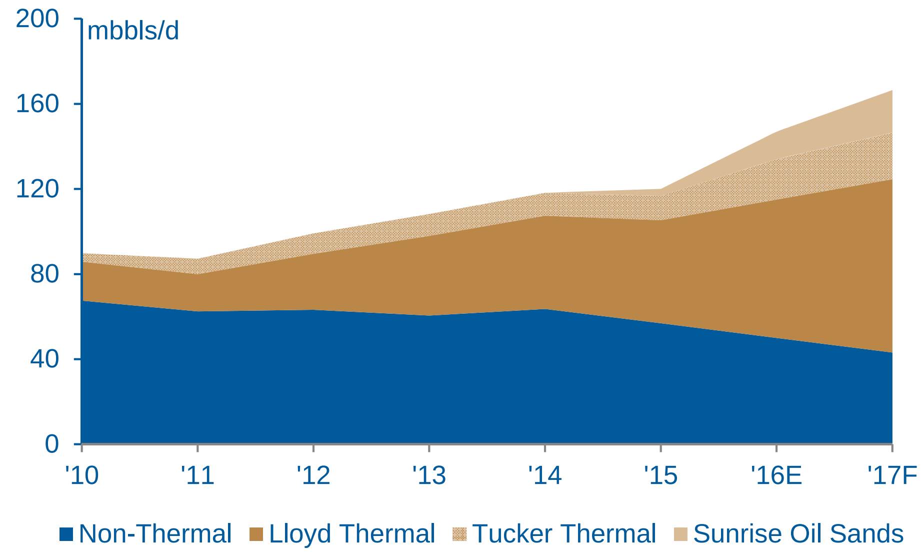
1. Other than as indicated in the Advisories, 10% IRR calculations are based on Proved and Probable reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on US$40 WTI price scenario.
3. Downstream portfolio IRR not directly tied to oil or gas price. See Advisories for further detail.
4. WTI and AECO prices as of December 12, 2016. AECO gas prices converted to US$ at a CAD/USD 0.76 exchange rate.

Operations

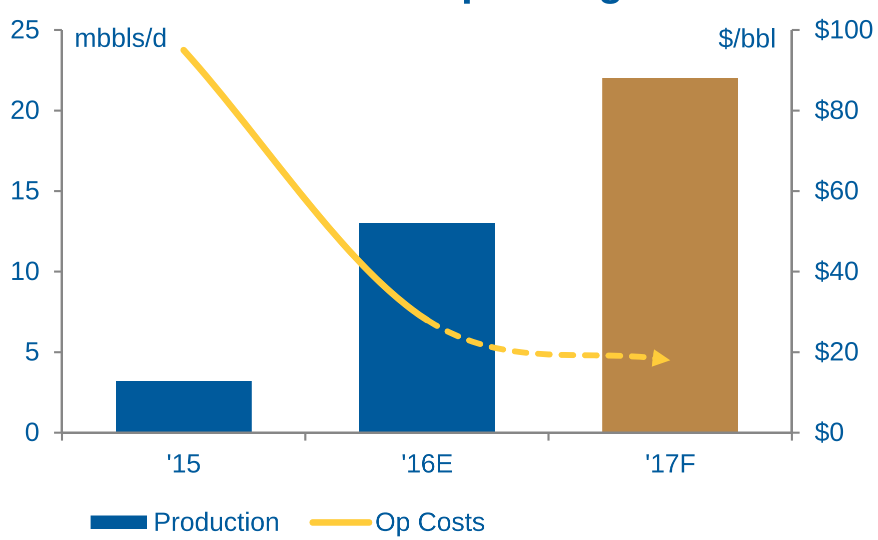
Thermal Operations Growth

- Low operating cost, long life reserves
- Low sustaining capital requirements ($5-7/bbl)
- Current thermal production ~ 120,000 bbls/d
  (Lloyd thermals, Tucker & Sunrise)
- Inventory for next decade of growth
  - Lloyd: 150,000 bbls/d in potential future production
  - Tucker: 40+ years of potential production
  - Sunrise: Approved for future development up to an additional 140,000 bbls/d (gross)
- Integrated value chains
  - Sunrise production → Toledo Refinery
  - Lloyd & Tucker production → Upgrader → Lima Refinery
    → Asphalt Refinery

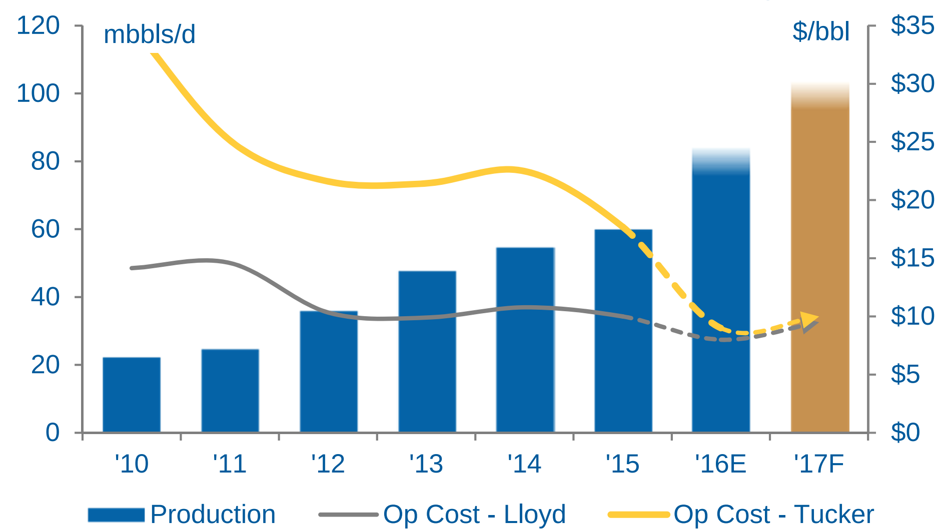
Thermal Heavy Oil Growth



Sunrise Production & Operating Costs



Lloyd / Tucker Production & Operating Costs



Next Wave Of Thermal Growth

- Full year contribution from 2016 projects
- 40,000 bbls/d of new thermal production sanctioned
  - Initial development of Rush Lake 2 (2019)
  - 3 additional projects sanctioned (2020)
- Future Inventory of 110,000 bbls/d (2021-2025)
  - 8 x 10,000 bbls/d, 6 x 5,000 bbls/d
- Tucker "D" pad. 15 wells to be drilled in 2017
  - Targeting 30,000 bbls/d in 2018

Economics	Tucker[1]	Lloyd[2]
Build Costs ($MM)	$ -	$350
Operating Costs ($/bbl)[3]	$9-10	$8-9
Royalty Rate	2%	7%
Crude Quality (API)	8^o-12^o	10^o-12^o
Differential to WCS ($/bbl)	~$6	~$2
DD&A ($/bbl)	~$14	~$11
Sustaining Capital Cost ($/bbl)	$5-7	$5-7
Project Life	> 40 yrs	> 15 yrs
Reserve Recovery Factor	> 50%	> 60%

1. Tucker refers to the economics of ongoing production.
2. Lloyd economics represent the forecast economics of a generic 10,000 bbls/d thermal project.
3. Operating costs include energy and non-energy costs.

Lloyd Thermal Project Inventory

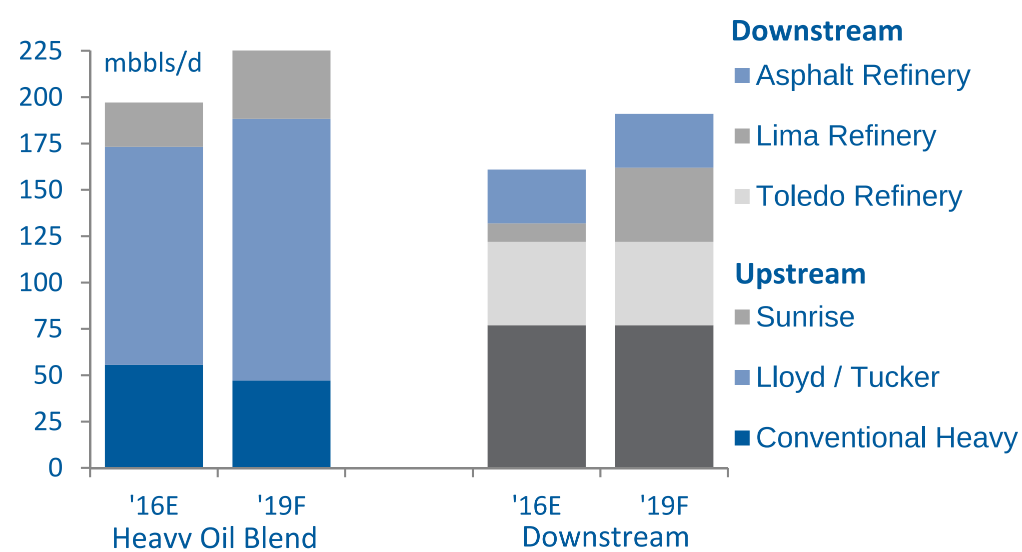
	Project Name (nameplate)	First Oil (year)	Current* / Forecast Production Rate (bbls/d)
Current Production			
Base	Base Production[1]	'84 - '14	39,200
Recent Projects *(2015-2016)*	Rush Lake *(10,000 bbls/d)*	2015	10,800
	Edam East *(10,000 bbls/d)*	Q2 '16	15,500
	Vawn *(10,000 bbls/d)*	Q3 '16	10,000
	Edam West *(4,500 bbls/d)*	Q3 '16	4,500
Near-Mid Term Production			
In Development	Rush Lake 2	1H 2019	10,000
Sanctioned[2]	Dee Valley	2020	10,000
	Spruce Lake North	2020	10,000
	Spruce Lake Central	2020	10,000
Future Production (2021+)			
Future Identified	14 projects. 110,000 bbls/d production potential (6 x 5,000 bbls/d , 8 x 10,000 bbls/d)		

1. Base production includes the Pikes Peak, Bolney Celtic, Celtic, Paradise Hill, Pikes Peak South and Sandall thermal oil projects as of December 1, 2016.
2. Subject to regulatory approvals.

Downstream – Physically Integrated Value Chains

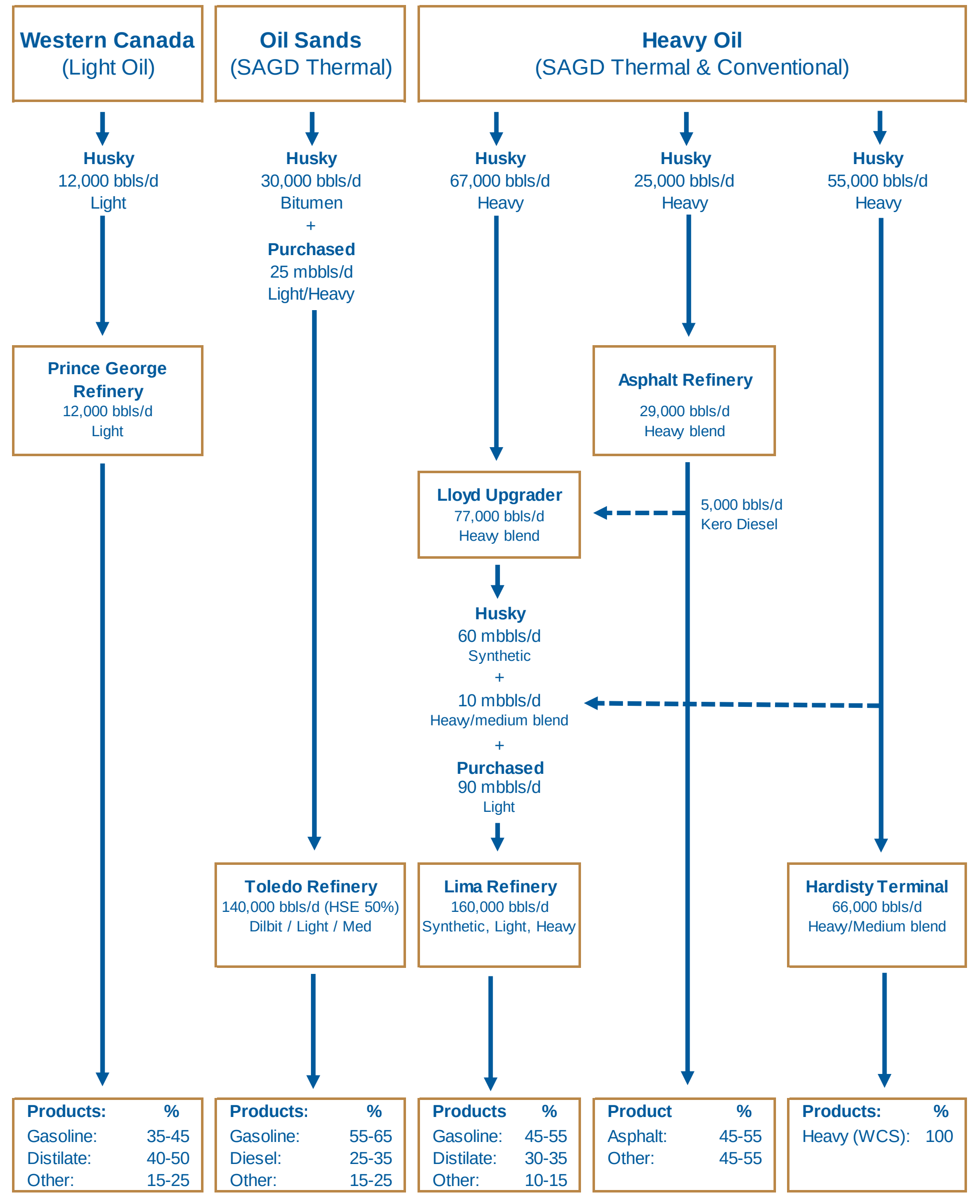
- Value chains add stability to cash flow from operations
  - Mitigates heavy oil differential
  - Increases margin capture
  - Flexibility of feedstock sources & finished product markets
- Total throughput capacity 340 mbbls/d (Upgrader & Refineries)
- Current capital projects
  - Lima Crude Oil Flexibility project (2019)
    - Heavy blend capacity increases to 40,000 bbls/d
- Asphalt capacity expansion evaluation underway

Matching Heavy Oil & Downstream Capacity



1. Production volumes represent blended volumes (heavy oil and diluent), Downstream facilities represent 100% nameplate capacity except Toledo (50%)

Integrated Value Chains

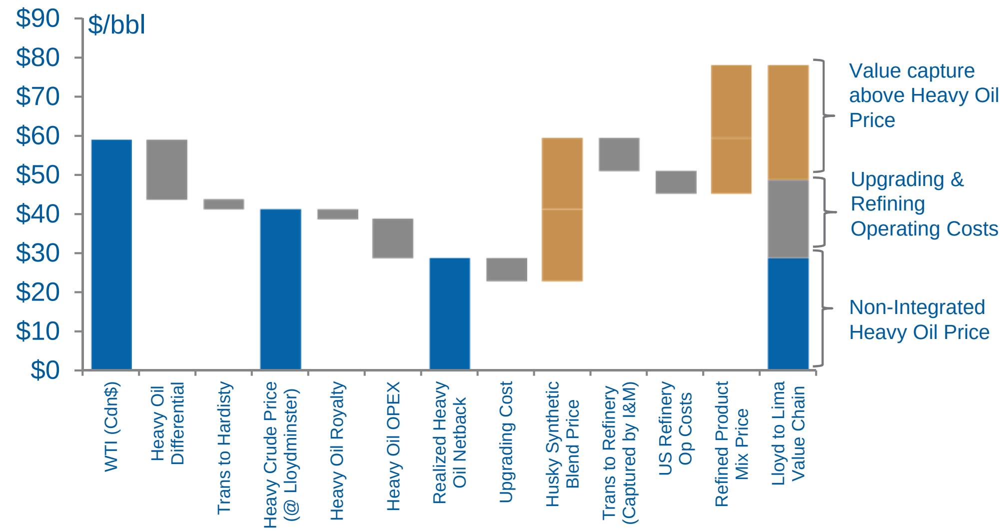


1. Product variability can be influenced by several factors, including seasonal demand, access to feedstock, distribution system interruptions.
2. Other products include propane, benzene, Sulfur, LPG, LVGO, HVGO, heavy fuels, petro-chemicals and other various by-products.

Value Capture Across The Downstream Portfolio

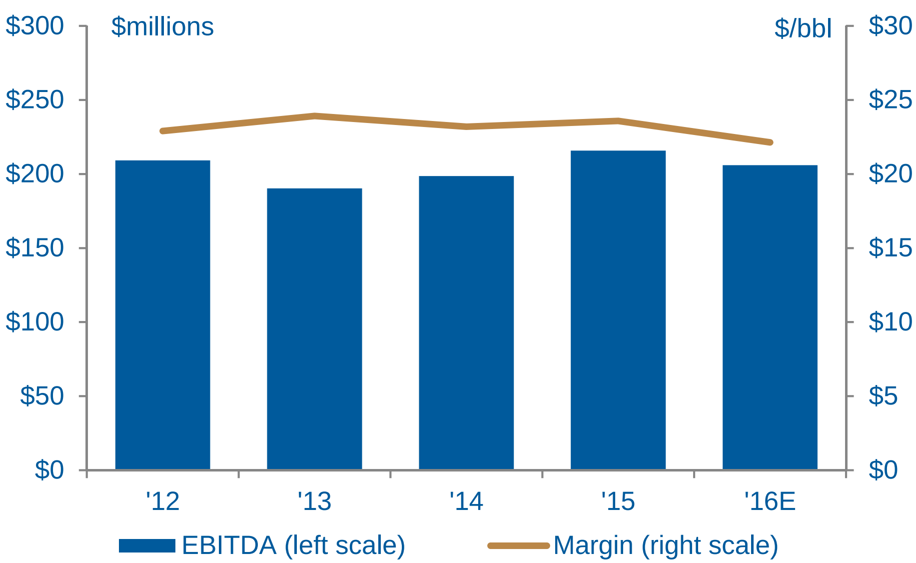
Flexible Market Access

Lloyd Value Chain[1]



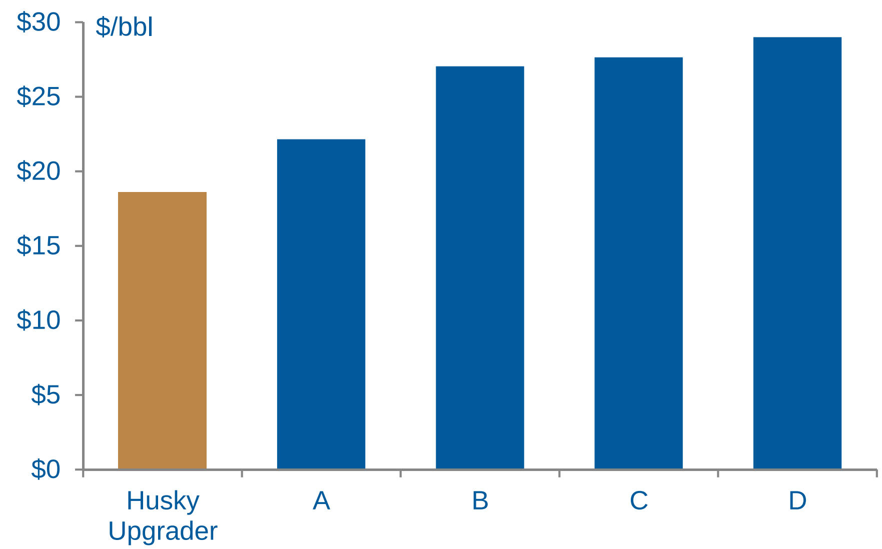
1. All crude prices and $/bbl costs reflect Q3/2016 averages. All values in $CAD based on 0.76 CAD/USD exchange rate.

Asphalt Plant Margin and EBITDA[1]



1. EBITDA is a Non-GAAP measure. See Advisories for further details.

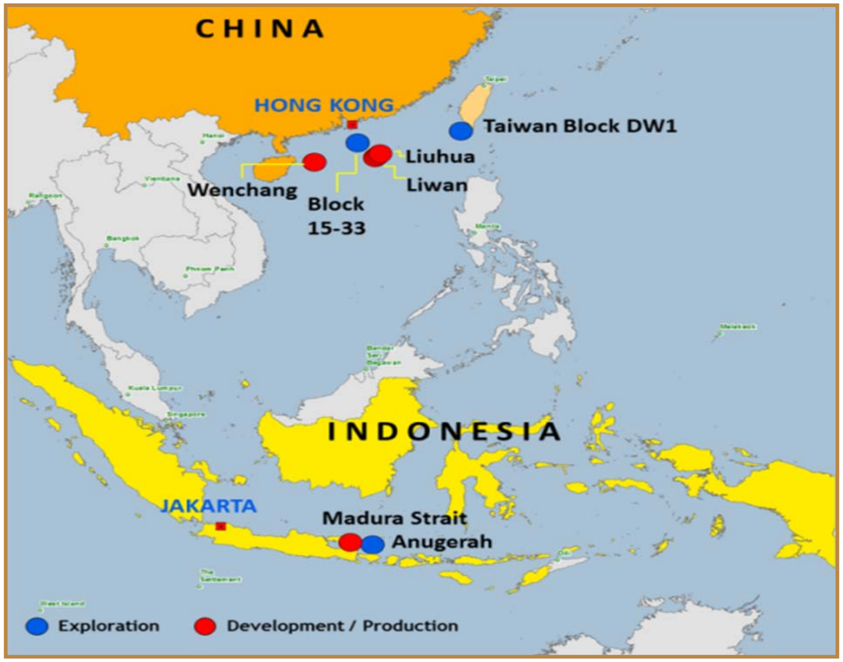
Synthetic Crude Oil Production Costs[1,2]



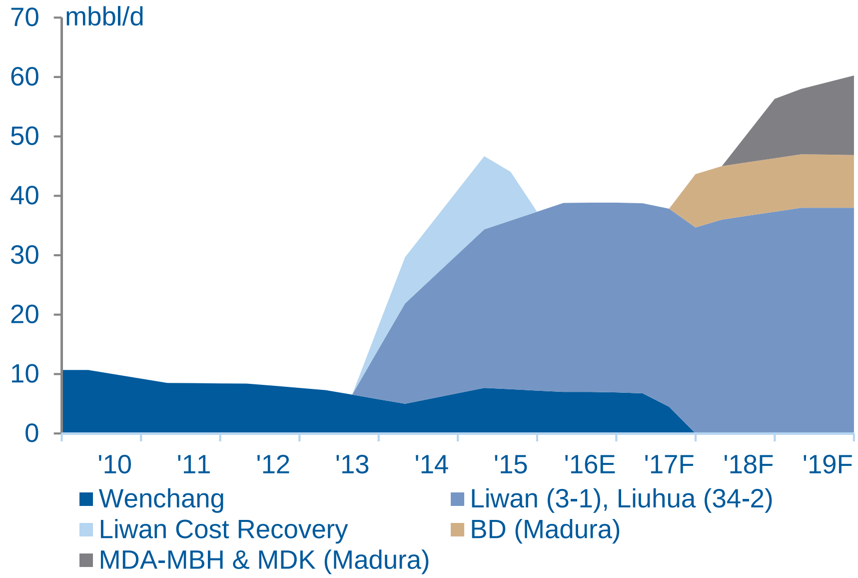
1. Synthetic crude oil production costs include operating costs related to bitumen or thermal heavy oil production, transportation costs to upgrading facilities, upgrading costs. Information taken from MD&A report of the listed companies for the reporting period for the three months ending September 30, 2016. See Advisories for further details
2. Peers include: CNRL, Imperial Oil, Suncor and Syncrude.

Growing Asia Pacific Business

- Platform of stable cash flow from operations growth
  - Fixed-price gas contracts
  - Low cost operations
- Productions increases up to 60,000 boe/d from near term projects
  - Current — Liwan (Liwan 3-1, Liuhua 34-2)
  - Near Term — Indonesia (BD, MDA-MBH, MDK)
- Future growth potential
  - Mid Term — Liuhua 29-1
  - Long Term — Further exploration in China (light oil) and Indonesia (gas)



Asia Pacific Growth Profile



Asia Pacific – Fixed Prices and Growth

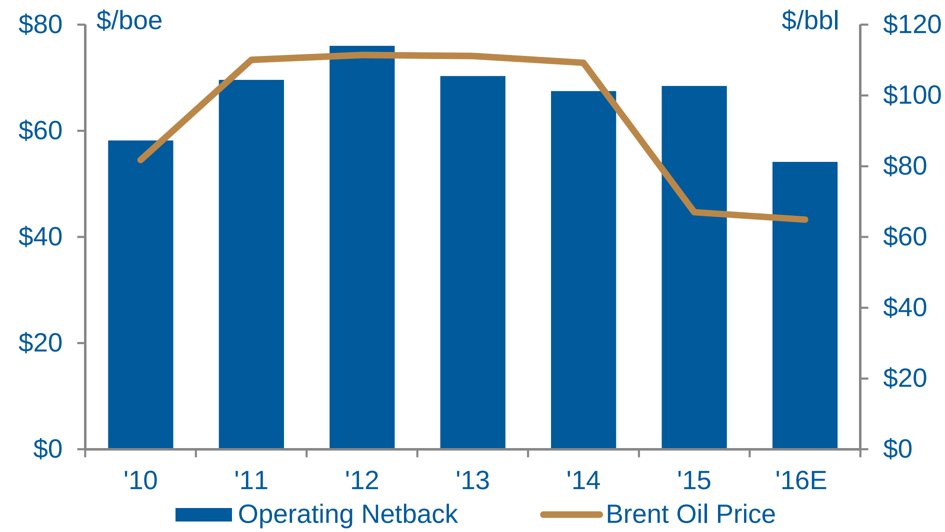
China

- Liwan Gas Project
    - Fixed price – $12.50-$15.00/mcf
    - Take or Pay contract – 300-330 mmcf/d (gross)
    - Liuhua 29-1
- Wenchang light oil
    - PSC ends 2H/2017 (~7,000 bbls/d)
- Future exploration blocks
    - 15/33 exploration well 2018
    - Taiwan 3D seismic of plot being evaluated

Indonesia (Madura Strait)

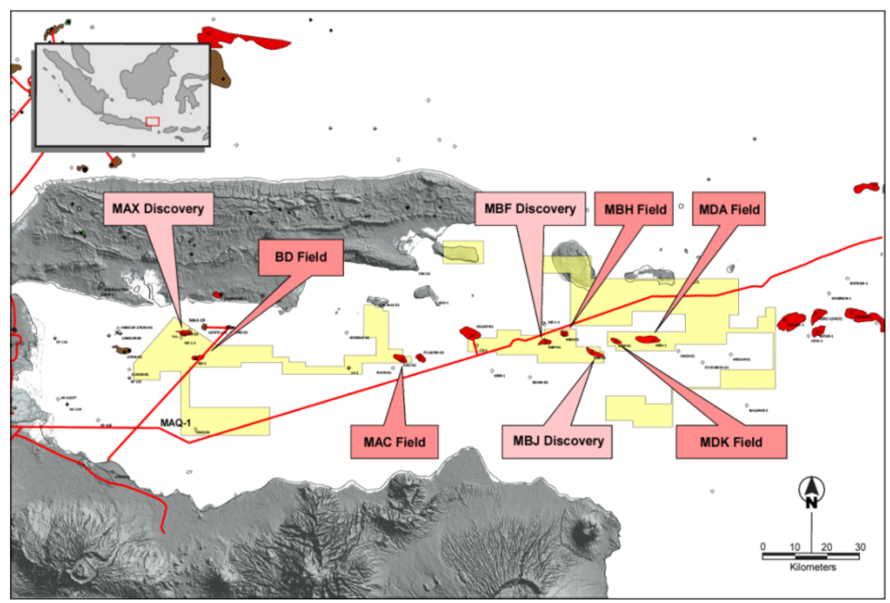
- BD field - 2H/2017 (40mmcf/d + 2.4 mbbls/d)
- MDA-MBH & MDK fields – 2018/19 (60mmcf/d)
- Fixed price – $6.50-$7.50/mmbtu
- Future exploration blocks

Asia Pacific Operating Netback[1]



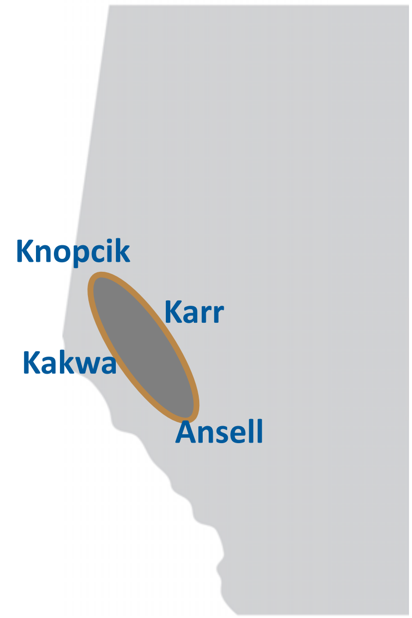
1. Operating netback is a non-GAAP measure. Please see Advisories for details.

Madura Strait Developments

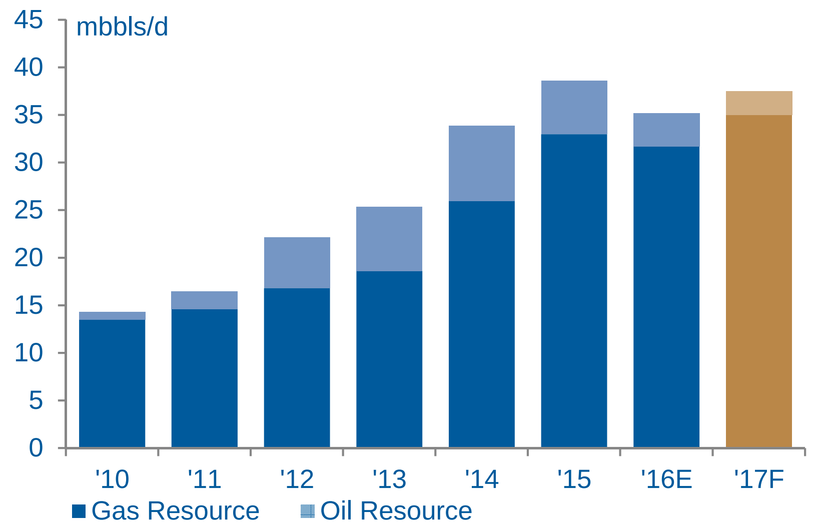


Western Canada – Growing Resource Plays

- Growing resource production offsets legacy production declines
  - Improving operating costs, DD&A, F&D
  - Short cycle investments allow for increased capital efficiency
- Core plays
  - Wilrich – Ansell, Kakwa
  - Montney – Karr, Knopcik
- 2017 development program
  - 16 new wells planned at Ansell and Karr
  - Target 6,000 boe/d in production adds by year end 2017
  - Ongoing disposition program

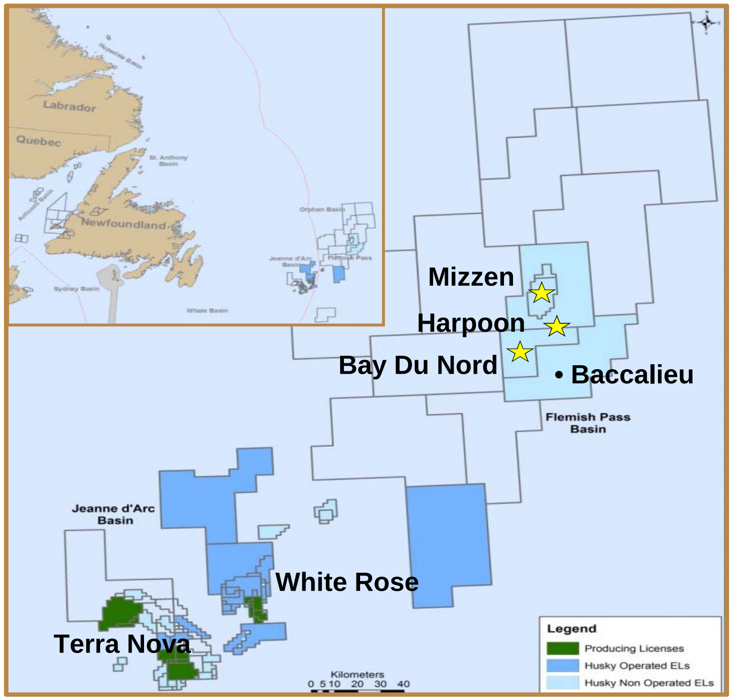


Resource Play Production

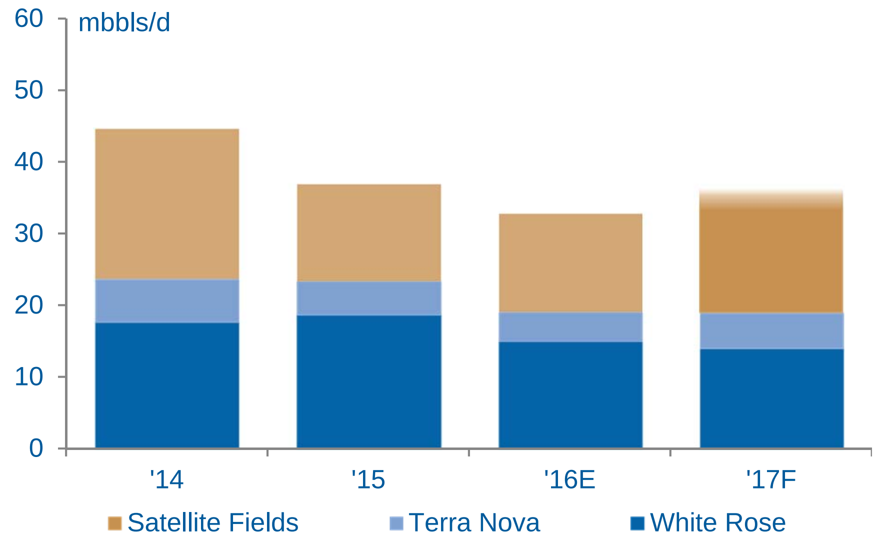


Atlantic Region – Infills Bridging To Future Growth

- Stable production base with potential growth upside
  - High operating netback production
    - Pricing premium to Brent
    - Low cost operations
  - Mitigate base field declines with infill drilling at White Rose field extensions
  - Enhanced economics through use of existing infrastructure (SeaRose FPSO)
- 2017 planned activity
  - Two infill wells
    - Combined peak production of 15,000 bbls/d
  - West White Rose evaluation ongoing
  - Flemish Pass appraisal underway



Atlantic Region Production



Solid Position

Vitals

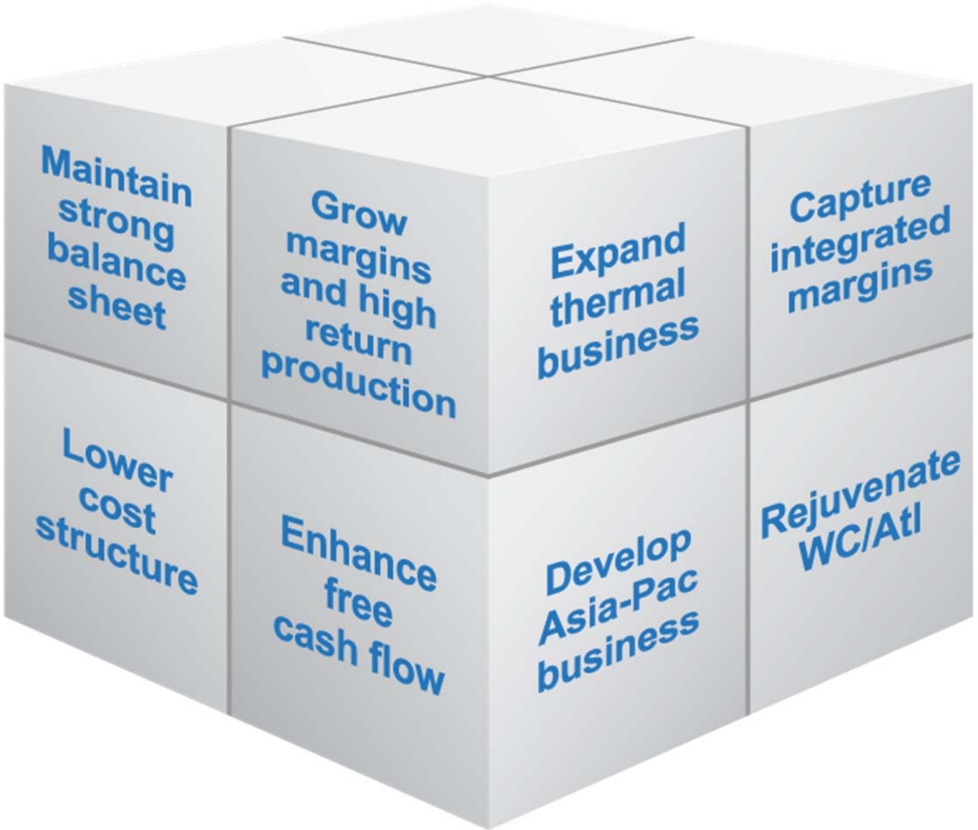
- Strong balance sheet
- Low cost structure, getting lower
- Deep portfolio of high return projects

Strategic deliverables for 2017

- Maintain balance sheet strength
- Continue to lower cost structure
- Growth of higher return production
- Free cash flow generation

Priorities for Free Cash Flow

- Further investment in our deep portfolio
- Establish a sustainable cash dividend



Guidance Appendix

Husky Energy

2017 Guidance Planning Assumptions

December 13, 2016

Upstream

Oil and Liquids	Capital Expenditures[1] ($ millions)	Production (mbbls/day)
Lloyd & Tucker thermal[2]	600 - 630	103 - 105
Oil Sands thermal	90 - 100	20 - 22
Lloyd Non-Thermal	85 - 90	44 - 46
Atlantic Region light	320 - 335	35 - 37
W. Canada Light, medium, heavy & NGLs	60 - 65	19 - 20
Asia Pacific light & NGLs[3]		13 - 15
Total Crude Oil and Liquids	**1,155 - 1,220**	**234 - 245**

Natural Gas	($ millions)	(mmcf/day)
Canada	150 - 160	345 - 353
Asia Pacific Region	230 - 240	171 - 182
Total Natural Gas	**380 - 400**	**516 - 535**

	($ millions)	(mboe/day)
Total Upstream	**1,535 - 1,620**	**320 - 335**

Downstream	Capital Expenditures ($ millions)
Canada downstream	325 - 350
US downstream	400 - 415
Downstream Total	**725 - 765**

Corporate Costs	
Unallocated Capital ($ millions)	200 - 250
Corporate Capital ($ millions)	95 - 105
Total Capital Budget	**2,555 - 2,740**
Other Capital Items ($ millions)[5]	350 - 400
Corporate SG&A ($ millions)	200 - 300
Sustaining Capital ($ millions)	
Upstream	1,550 - 1,600
Downstream	650 - 700
Total Sustaining Capital	**2,200 - 2,300**
2017 Price Planning Assumptions	
WTI, Cushing ($US/bbl)	48.00
3-2-1 Chicago Crack ($US/bbl)	16.00
Natural Gas, AECO ($Cdn/mcf)	2.50
Exchange Rate ($US/$Cdn)	0.76

Operating Costs	
Upstream	**($/bbl)**
Lloyd and Tucker thermal[4]	9.25 - 10.25
Atlantic Region light oil	17.00 - 19.00
	($/mcfe)
Canadian Natural Gas	1.00 - 1.30
Asia Pacific Region Gas	1.10 - 1.40
	($/boe)
Total Upstream Operating Costs	**14.00 - 15.00**
Downstream[6]	**($/boe)**
Lloyd Upgrader	7.50 - 8.50
US Refineries	6.00 - 8.00

1. Capital expenditures include Exploration capital in each respective business unit.
2. Lloyd and Tucker thermal capital expenditures includes Lloyd thermal heavy oil and Tucker Lake bitumen.
3. Asia Pacific Region oil & NGLs operating costs and capital expenditures refected in Asia Pacific natural gas.
4. Lloyd and Tucker thermal operating costs include energy and non-energy costs.
5. Includes ARO, capitalized interest and contribution payable.
6. Includes the impact of scheduled turnarounds in 2017.

Advisories

Forward-Looking Statements and Information

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”, “forecast”, “guidance”, “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 sustaining and maintenance capital for 2017, broken down by business segment; anticipated proportion of total production from low sustaining capital cost projects by year end 2017; estimated breakdown by product type of forecasted 2017 production; forecasted operating cost per barrel for 2016 and 2017; the Company’s forecasted net debt for 2016 and 2017; the Company’s key deliverables, broken down into strategic and operational objectives, for 2017; capital spending and sustaining and maintenance capital guidance ranges for 2017; capital expenditures and production guidance ranges for 2016 and 2017; estimated breakdown by business segment of forecasted capital spending and sustaining and maintenance capital; estimated breakdown by region and business segment of forecasted 2017 capital expenditures; estimated thermal and total upstream production growth for 2017; estimated breakdown by product type and region of forecasted 2017 production; estimated volume of new high return production to be added in 2017; forecasted 2017 downstream and upstream sustaining capital, portfolio investments and other non-discretionary capital expenses, and resulting free cash flow generation for range of WTI prices; forecasted 2016 (average) and 2017 (exit rate) for earnings break-even and cash flow break-even; forecasted 2016 (average) and 2017 (exit rate) for volumes of low sustaining capital production and all other remaining production; projected prices required to generate targeted IRR for the Company’s listed in-flight and future projects; costs and time frames to develop, and other factors affecting the development of, and the Company’s contingent resources; planned establishment of a sustainable cash dividend;

- with respect to the Company's Asia Pacific Region: potential production growth from Asia Pacific current through to long term projects; anticipated production volumes from Wenchang, Liwan Cost Recovery, MDA-MBH and MDK (Madura), Liwan 3-1 and Liuhua 34-2 and BD (Madura) through to 2019; planned timing of first production at, and targeted combined daily volumes of production from, the Madura Strait MDA-MBH and MDK fields; planned timing of first production at, and targeted combined daily volumes of production from, the BD field; planned timing of exploration drilling on block 15/33; and forecasted Asia Pacific Netback for year end 2016;

- with respect to the Company's Atlantic Region: planned timing of, and combined net peak production from, White Rose infill wells; and estimated potential increase in daily production with the West White Rose Extension options; and total and segmented Atlantic Region production for 2016 and 2017;

- with respect to the Company's Heavy Oil properties: strategic plans and growth strategy for the Company’s Lloyd thermals; forecasted heavy oil thermal and non-thermal production for 2016 and 2017; forecasted daily production volumes from Sunrise for 2016 and 2017; forecasted production from, and operating costs for, Tucker and Lloyd thermals for 2016 and 2017; potential future production volumes from Lloyd thermals; potential production lifespan from Tucker thermals; 2017 drilling plans for Tucker “D” pad; targeted 2018 daily production from Tucker; forecasted project economics for Tucker and Lloyd thermals; forecasted first oil dates and nameplate capacity for the Company’s near-mid term Lloyd thermal projects; and forecasted first oil date ranges and nameplate capacity for the Company’s potential future Lloyd thermal projects;

- with respect to the Company's Western Canadian oil and gas resource plays: the Company’s 2017 development program for its Western Canada portfolio; and Western Canada resource play production broken down into resource type for 2016 and 2017; and

- with respect to the Company's Downstream operating segment: anticipated date of completion for the Lima crude oil flexibility project and resulting change in heavy capacity throughput; forecast heavy oil production and downstream throughput for 2016 and 2019; and projected asphalt plant margin and EBITDA for year end 2016.

In addition, statements relating to “reserves” “and” “resources” are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and resources and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserve, resource and production estimates. In addition, with respect to the type curves, there is no certainty that future well will generate results to match type curves presented herein.

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.

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.

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, 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, amortization and impairment, 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 loss (gain), and other non-cash items.

- The term 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, amortization and impairment, 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 loss (gain), and other non-cash items less capital expenditures.

Advisories

- The following table shows the reconciliation of cash flow – operating activities to cash flow from operations and the reconciliation of free cash flow – operating activities to cash flow from operations for the nine months ended September 30, 2016 and the year ended December 31, 2015:

Cash Flow from Operations and Free Cash Flow

		Q1 2016	Q2 2016	Q3 2016	2016 YTD	2015
GAAP	Net earnings (loss)	(458)	(196)	1,390	736	(3,850)
	Items not affecting cash:				0	
	Accretion	34	33	29	96	121
	Depletion, depreciation and amortization	722	697	638	2,057	8,644
	Inventory write-down to net realizable value	0	0	0	0	22
	Exploration and evaluation expenses	0	30	0	30	242
	Deferred income taxes	(7)	(108)	99	(16)	(1,827)
	Foreign exchange	1	12	12	25	27
	Stock-based compensation	17	8	5	30	(39)
	Loss/(gain) on sale of assets	2	96	(1,680)	(1,582)	(16)
	Unrealized mark to market	123	(83)	(28)	12	(14)
	Other	0	(1)	19	18	19
Non- GAAP Cash flow from operations		**434**	**488**	**484**	**1,406**	**3,329**
	Capital expenditures (1)	(456)	(618)	(348)	(1,422)	(3,042)
Non- GAAP Free Cash Flow		**(22)**	**(130)**	**136**	**(16)**	**287**

(1) Includes expenditures on exploration and evaluation assets (Q1 2016 - $16 million, Q2 2016 - $11 million, Q3 2016 - $5 million, 2015 - $205 million), expenditures on property, plant and equipment (Q1 2016 - $394 million, Q2 2016 - $584 million, Q3 2016 - $304 million, 2015 - $2,800 million) and expenditures on investment in joint venture. (Q1 2016 - $46 million, Q2 2016 - $23 million, Q3 2016 - $39 million, 2015 - $37 million).

- Net debt to cash flow from operations is a non-GAAP measure 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. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

- 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.

- Sustaining and maintenance capital is the additional capital that is required by the business to maintain production and operations at existing levels. 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. IRR calculations are based on holding certain 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. These measures do not have any standardized meanings 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, 2017. 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.

- Cash Flow break-even reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate operating cash flow equal to the Company's sustaining capital requirements in CAD in the 12 month period ending December 31, 2017. 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.

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.

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 $700 million based upon the pre-development studies. The estimated total capital to fully develop these 8 development pending projects is approximately $8 billion. 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. This heavy crude oil is reported as thermal bitumen and has viscosities ranging from 12,800 centipoise (cP) to as high as 600,000 cP with gravities between 10 and 22.3 degrees API. 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.

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 results of the commercial demonstration will be utilized to refine the subsequent phases that 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 total commercial facilities and wells will be developed over more than 50 years at an estimated total cost of $40 billion in accordance with the conceptual study for this large resource. The development of these projects depends on the results of the technical analysis, future bitumen 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.

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.

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.

Advisories

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).

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 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.

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.