Husky Energy

2016 Annual Meeting of Shareholders

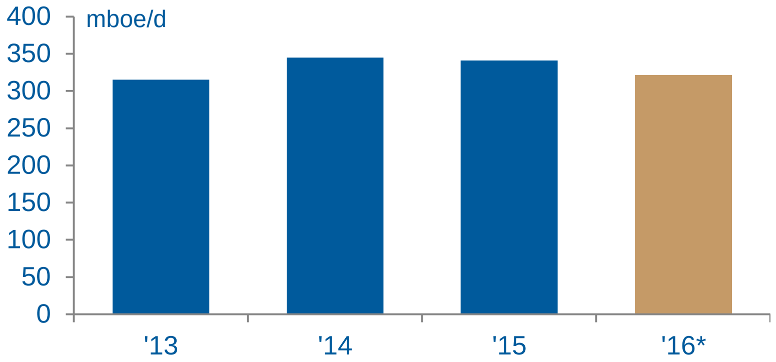
May 5, 2017

Resilient Growth Portfolio

2016 Highlights

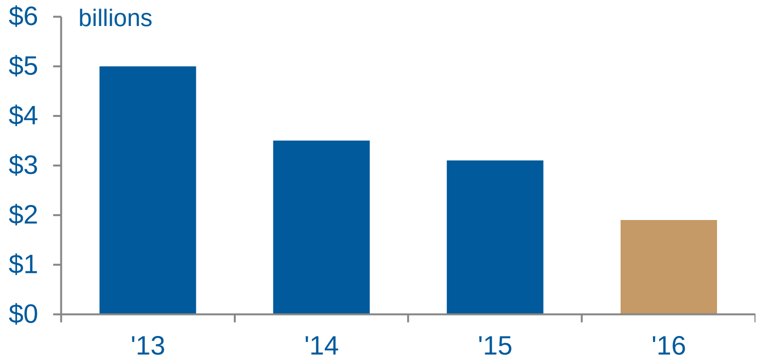
- Average annual production **321,000 boe/day**
- Net earnings **$922 million**
- Funds from operations[1] **$2.1 billion**
- Capital spending **$1.9 billion**
- Net debt[1] **$4.0 billion**

Production



* Reflects dispositions

Capex[2]



1, 2 See Slide Notes and Advisories

Strategy On Course

- Strengthen balance sheet ✓
- Further improve cost structure ✓
- Build out inventory of high quality projects ✓

Vawn Lloyd Thermal Project

Lloyd Asphalt Refinery

Debt Metrics

Net debt of $4 billion

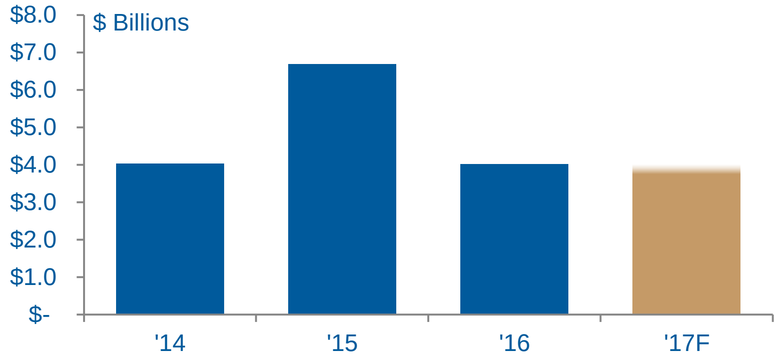
- $4 billion in undrawn credit facilities
- $2.2 billion cash on hand (*as at March 31, 2017*)

Strong investment grade credit rating

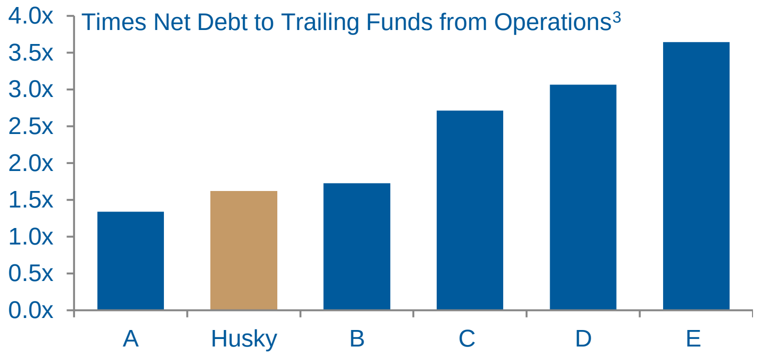
- Moody's – Baa2; Stable
- S&P – BBB+; Stable
- DBRS – A (low); Stable

- No major long-term bond maturities until 2019

Net Debt



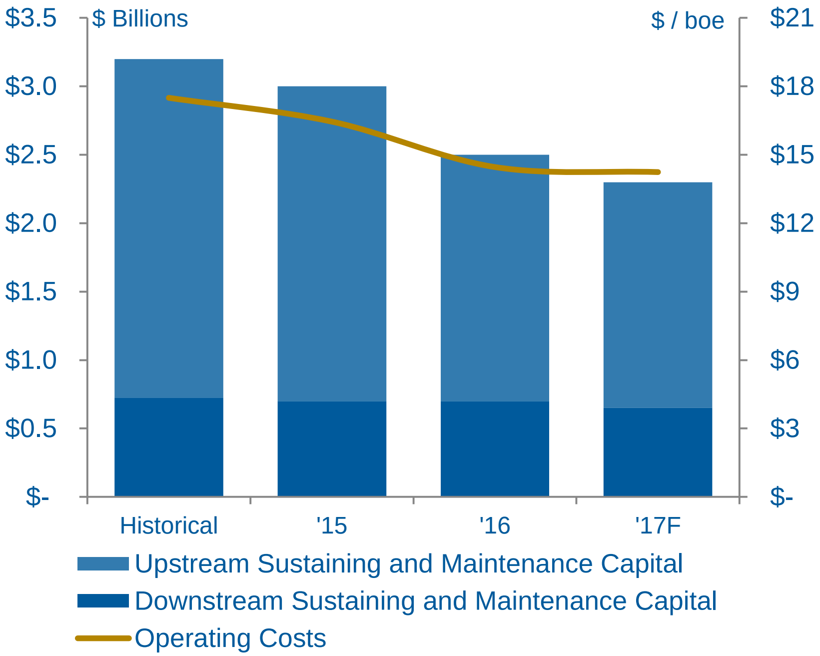
Comparable Debt Metrics[1,2]



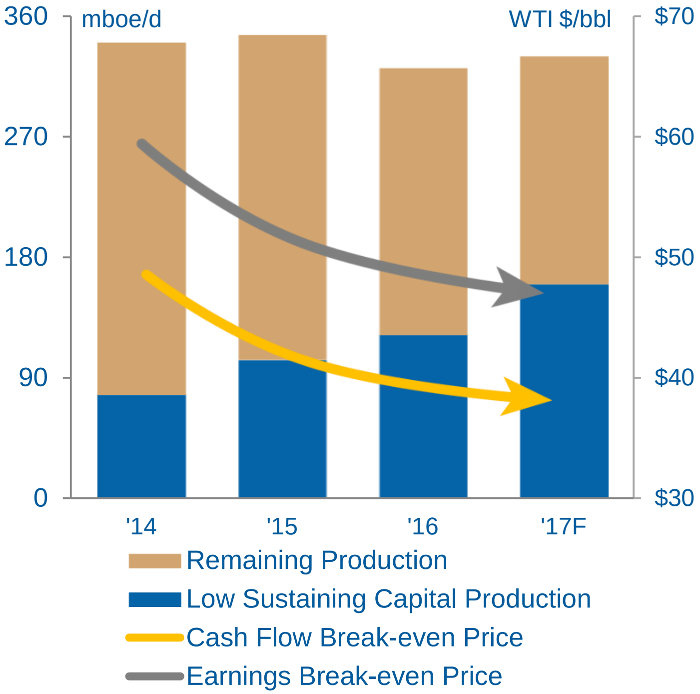
1, 2 See Slide Notes and Advisories

Improved Cost Structure

Lower Cost Structure[1]



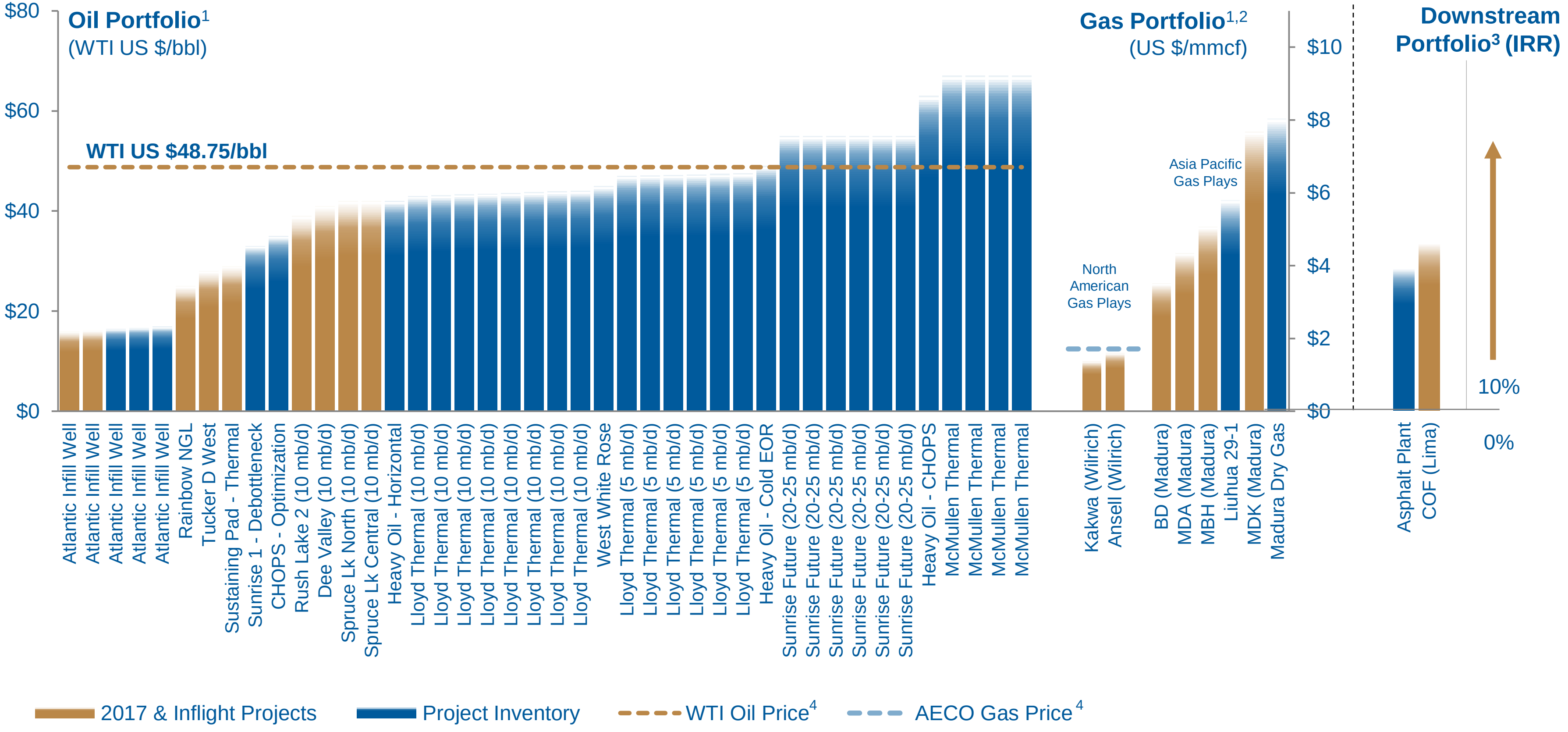
Lower Break-Even Prices[2]



1, 2 See Slide Notes and Advisories

Returns-Focused Investment

Price Required to Generate 10% IRR



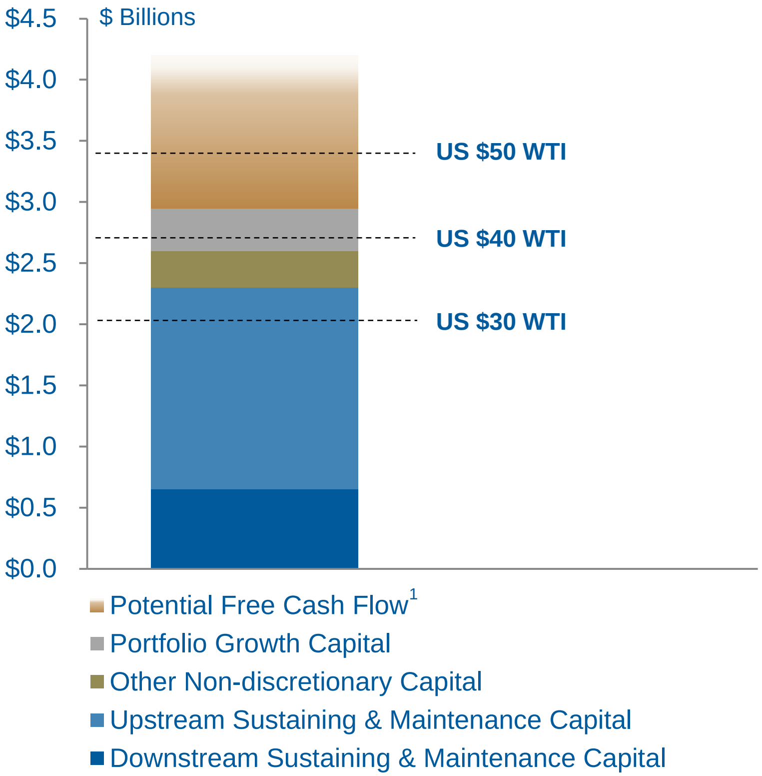
1, 2, 3, 4 See Slide Notes and Advisories

Positioned for Free Cash Flow Generation

Free cash flow priorities:

- Maintain balance sheet strength
- Free cash flow generation
- Invest to further improve cost structure
- Return cash to shareholders

2017 Free Cash Flow Generation



1, See Slide Notes and Advisories

Operations

Husky Energy

Strong Focus on Safety and ESG

Improved safety performance

- Critical and serious incidents down 92%
- Total Recordable Incident Rate down 45%

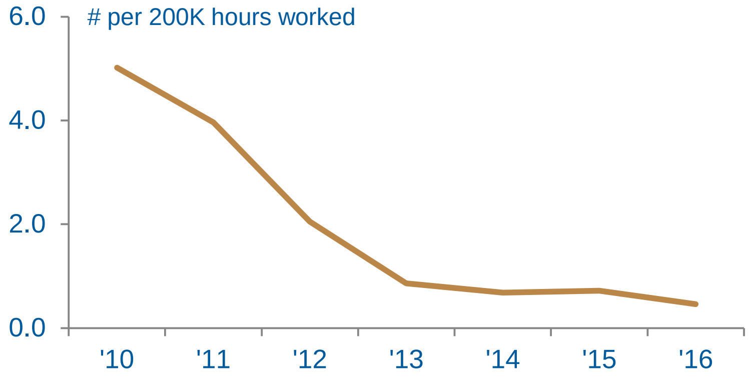
Environmental, Social and Governance (ESG) focus

- Added to the Jantzi Social Index (February 2016)
- 2016 CDP Climate and Water (“B” scores)
- Corporate Knight’s Best 50 Corporate Citizens in Canada (2016)

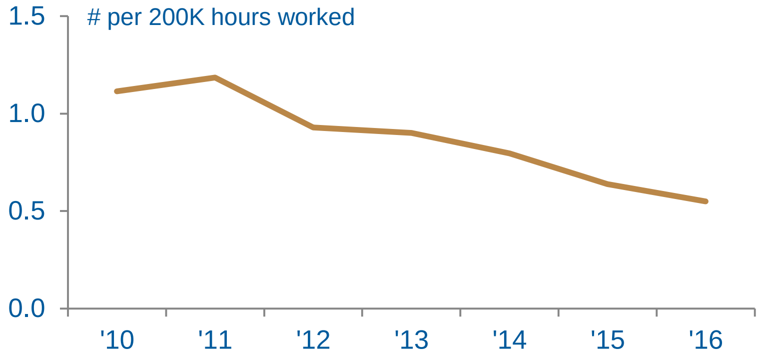
Saskatchewan pipeline release

- Effective response led to recovery of 90+ percent
- Continue to work closely with government and communities
- Findings contributing to improved operations

Critical & Serious Incidents



Total Recordable Incident Rate



2017 Capital and Production Guidance

Capital Spending

Total	**$2.6 – $2.7 Billion**
Upstream:	$1.7 – $1.8 billion
Downstream:	$0.7 – $0.8 billion
Corporate:	$0.1 billion

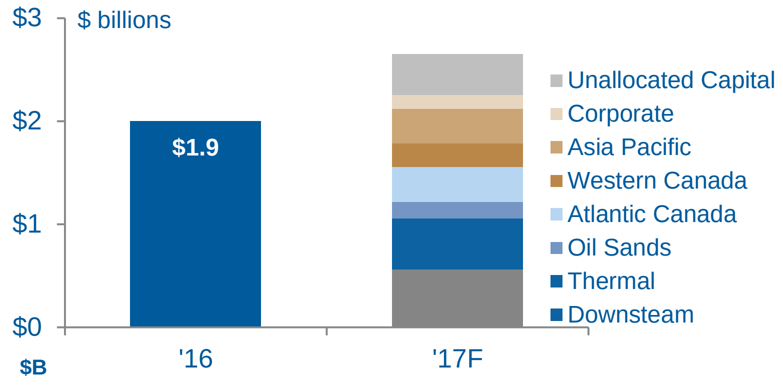
Sustaining and maintenance capital

Total	**$2.2 – $2.3 billion**
Upstream:	$1.6 billion
Downstream:	$0.7 billion

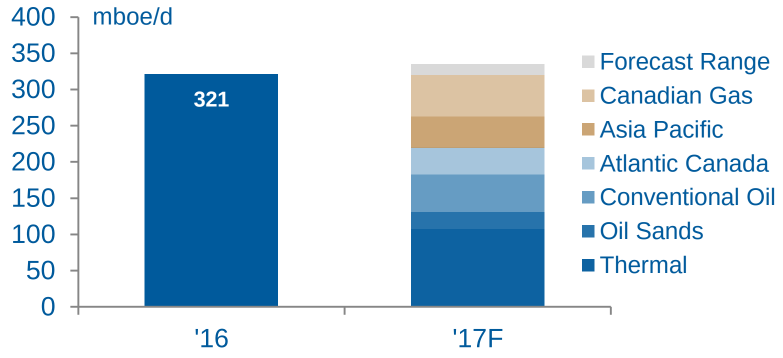
Upstream Production

- Average production of 320,000 – 335,000 mboe/day
  - Production growth of up to 5%
  - Thermal operations growth of 30%
  - ~ 45,000 boe/day new production

Capex: $2.6 - 2.7 Billion[1]



Production Range: 320 – 335 mboe/day



1 See Slide Notes and Advisories

Thermal Operations – Long Life, Low Cost Production

Current thermal production of ~120,000 bbls/day

(Lloyd, Tucker, Sunrise)

Sizable project inventory

- Lloyd: 150,000 bbls/day in potential production
- Tucker: 40+ years of expected production
- Sunrise: Approved for development up to an additional 140,000 bbls/day (gross)

Low operating costs

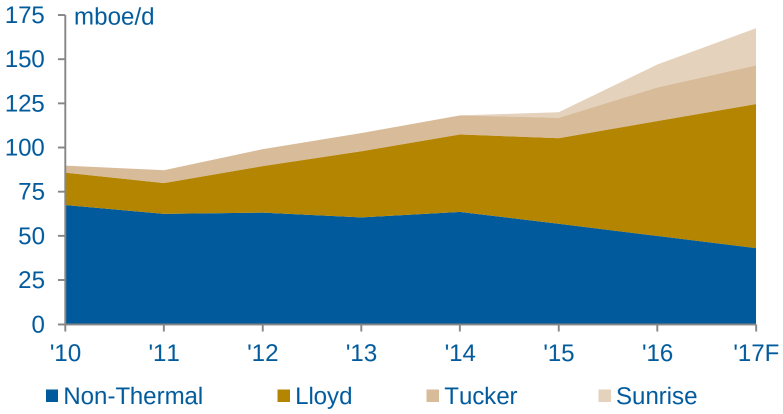
- Overall thermal operating costs of $11.83 per barrel

Low ongoing capital requirements

- Lloyd and Tucker capital costs of $5-7 per barrel
- Sunrise capital costs of $7-8 per barrel

Edam West Lloyd Thermal Project

Thermal Growth



Downstream – Improving Margins

340,000 bbls/day throughput capacity

Value chain adds stability to funds flow

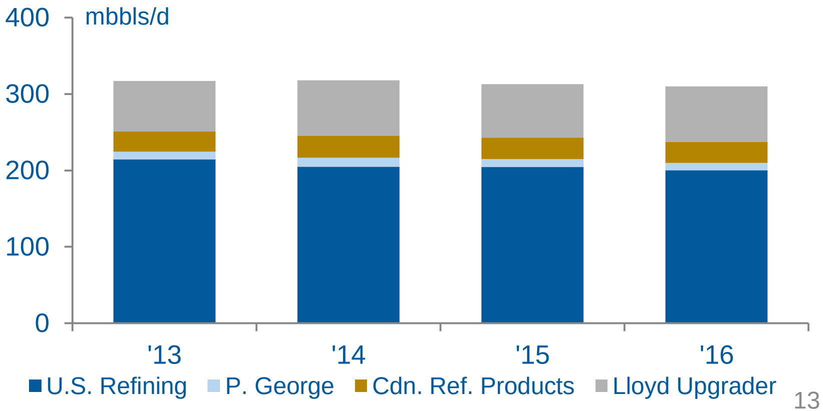
- Mitigates heavy oil differential
- Increases margin capture
- Investments improving flexibility of feedstocks, product range and market access

Current capital projects

- Lima crude oil flexibility project (2019)
    - Heavy blend capacity increasing to 40,000 bbls/day
- Ongoing evaluation of Lloyd asphalt capacity expansion

Lima Refinery

Downstream Throughput



Western Canada – Capital Efficient Resource Plays

Growing resource production

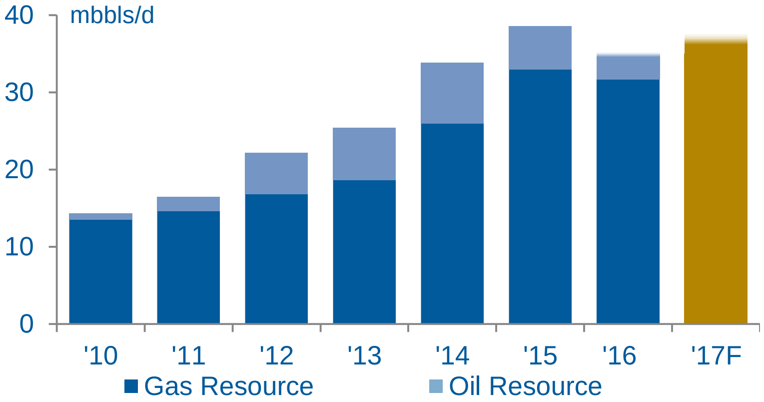
- Offsetting legacy production declines
- Improving operating costs, DD&A, F&D
- Short cycle investments increasing capital efficiency
- Gas providing supply and natural hedge for thermal operations

2017 development program

- 16 wells at Ansell and Kakwa
- Targeting 6,000 boe/day in production adds by year-end 2017

Ansell

Resource Play Production



Asia Pacific – Growing Fixed-Price Business

Low-cost operations

- Solid netbacks
- Less exposure to commodity price volatility

Near-term production adds

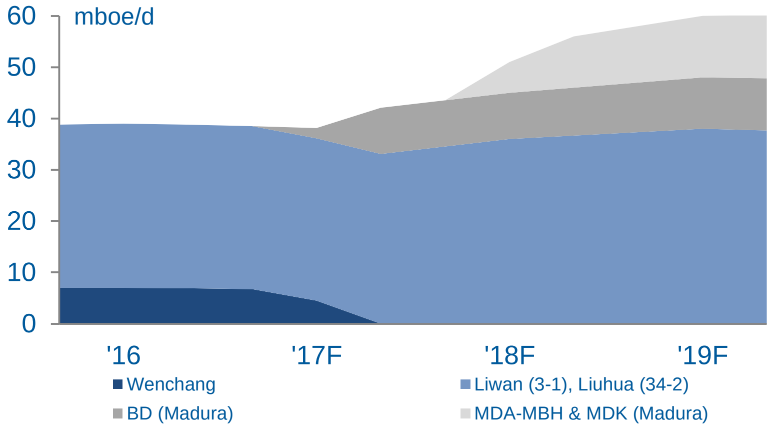
- Production increases 2x to 60,000 boe/day
    - Liwan (Liwan 3-1, Liuhua 34-2)
    - Indonesia (BD, MDA-MBH, MDK)

Mid and long-term growth potential

- Liuhua 29-1 (offshore natural gas)
- Further exploration in China (light oil)

BD Project

Asia Pacific Growth Profile



Atlantic – High Netback Growth

Growth upside

- High operating netback production
- Pricing premium to Brent oil price
- Low cost operations

Supporting production

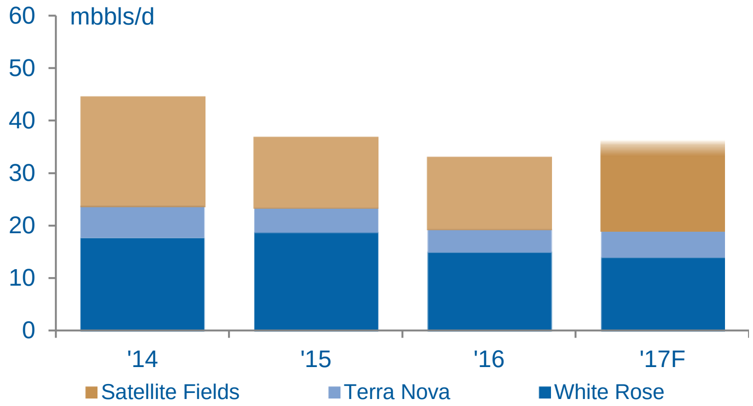
- Infill drilling at White Rose extensions
- Capital efficient use of existing infrastructure

2017 planned activity

- Two White Rose infill wells with expected combined net peak production of ~15,000 bbls/day
- Two exploration wells in Flemish Pass Basin

SeaRose FPSO

Atlantic Region Production



Summary

2016 Milestones

- Progressed thermal program and identified an additional 150,000 bbls/day of production
- Unlocked value with Midstream and Western Canada transactions
- Improved Downstream margin capture
- Advanced high-netback offshore projects

2017 Priorities

- Invest to improve cost structure
- Maintain strong balance sheet
- Grow free cash flow

Slide Notes

Slide 3:
1. Funds from Operations and Net Debt, as referred to throughout this presentation, are a non-GAAP measure. Please see Advisories for further detail.
2. Excludes asset retirement obligations and capitalized interest.

Slide 5:
1. Peers include Cenovus, CNRL, Encana, Imperial, Suncor. Peer data sourced from public filings available on SEDAR as of December 31, 2016.
2. Net debt to trailing funds from operations ratio calculated by dividing net debt by 12-month trailing funds from operations as at December 31, 2016. Please see Advisories for further detail.

Slide 6:
1. Sustaining and maintenance capital, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
2. Low sustaining capital production, as referred to throughout this presentation, includes production from Tucker, Thermal, Sunrise and Asia Pacific natural gas.
3. Funds from operations break-even and earnings break-even prices, as referred to through out this presentation, have the meanings set out in the Advisories.

Slide 7:
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 $40 US WTI price scenario.
3. Downstream portfolio IRR not directly tied to oil or gas price. See Advisories for further detail.
4. WTI and AECO prices as of May 1, 2017. AECO gas prices converted to US$ at a CAD/USD 0.76 exchange rate.

Slide 8:
1. Potential free cash flow based on WTI price of $48 US per barrel, CAD$2.50 AECO gas price, 0.76 CAD/CAD exchange rate, US$16 Chicago 3-2-1 crack spread. Free Cash Flow, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.

Slide 11:
1. Excludes asset retirement obligations and capitalized interest

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 total production, break-even prices and proportion of total production from low sustaining capital cost projects by year end 2017; estimated breakdown by product type and region of forecasted 2017 production; the Company's forecasted net debt for 2017; capital spending and sustaining and maintenance capital guidance ranges for 2017, broken down by business segment; capital expenditures and production guidance ranges for 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 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; 2017 (exit rate) for earnings break-even and cash flow break-even; 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, other factors affecting the development of, and the Company's contingent resources; and free cash flow priorities to invest to further improve cost structure and to return cash to shareholders;

- 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, MDA-MBH and MDK (Madura), Liwan 3-1 and Liuhua 34-2 and BD (Madura) through to 2019;

- with respect to the Company's Atlantic region: planned timing of, and combined net peak production from, two infill wells; plans to drill two exploration wells in Flemish Pass Basin; and total and segmented Atlantic region production for 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 2017; forecasted daily production volumes from Sunrise for 2017; and; potential future production volumes from Lloyd thermals; potential production lifespan from Tucker thermals;

- 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 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

Advisories

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

Although the Company believes that the expectations reflected by the forward-looking statements presented in this 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, 2016 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 funds 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 “funds 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. Funds from operations is presented in this presentation to assist management and investors in analyzing operating performance by business in the stated period. Funds from operations equals Cash Flow – operating activities plus items not affecting cash which include settlement of asset retirement obligations, deferred revenue, income taxes received (paid), interest received and change in non-cash working capital.

Advisories

- 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.
- The following table shows the reconciliation of cash flow – operating activities to funds from operations and free cash flow for the years ended December 31:

Funds From Operations and Free Cash Flow

	2016	2015
Cash flow - operating activities	1,971	3,760
Items not affecting cash:		
Settlement of asset retirement obligations	87	98
Deferred revenue	(209)	(102)
Income taxes received (paid)	(3)	227
Interest received	(5)	(3)
Change in non-cash working capital	235	(651)
Funds From Operations	**2,076**	**3,329**
Capital expenditures (1)	(1,705)	(3,005)
Free Cash Flow	**371**	**324**

1. Capital expenditures in the Asia Pacific region exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture which is accounted for under the equity method. Subsequent to the second quarter of 2016, capital expenditures in Infrastructure and Marketing excludes amounts related to the Husky Midstream Limited Partnership ("HMLP") joint venture which is accounted for under the equity method.

Advisories

- Net Debt is a non-GAAP measure that equals total debt less cash and cash equivalents.

- Net debt to funds from operations is a non-GAAP measure that equals total debt less cash and cash equivalents divided by funds from operations. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Management believes these measurements assist management and investors in evaluating the Company's financial strength.

- 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 use 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.

- 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.

- Funds from Operations break-even reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate funds from operations 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, 2016 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, 2016.

Husky's Lloydminster Heavy Oil and Gas thermal bitumen unrisked best estimate contingent resources consist of 268 million barrels of economic development pending contingent resources and 554 million barrels of economic status undetermined development unclarified contingent resources. The figures represent Husky's working interest volumes. The development pending category consists of 11 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 2040. The first three projects have a total capital cost to first production of $1.2 billion based upon the pre-development studies.

The estimated total capital to fully develop these 12 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, 147 million barrels of thermal bitumen are based upon pre-development studies while an additional 675 million barrels of thermal bitumen are based upon conceptual plans. This 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 9 and 12 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 $452 million for the initial commercial demonstration facility and horizontal cyclic steam stimulation (HCSS) wells in 2023. 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 2028 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.

Advisories

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 248 million barrels of oil equivalent, comprised of 1.4 tcf of natural gas and 14 million barrels of NGL. The initial contingent resource fracture stimulated horizontal wells are scheduled to be drilled starting in 2024, following the development of the proved and probable reserves. The cost to achieve initial commercial production is the cost of the first well of $4.5 million. The remaining wells (259 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 $650 million with an on-stream date in 2018. 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.

Husky's Lloydminster Heavy Oil cold heavy oil production with sand (CHOPs) and Horizontal well opportunity includes 189 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 $580,000 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.

Advisories

Heavy Oil Cold EOR, located in the Lloydminster area, contains 307 million barrels (Husky's working interest) of unrisked economic status undetermined 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 indicated.

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