Husky Energy

NEWS RELEASE
Calgary, Alberta
May 30, 2017

Husky to Present Five-Year Growth Plan at Investor Day

Five-Year Plan Highlights[1]

Key Metrics	2017	2017 – 2021F CAGR[2]	2021F
Production (mboe/day)	**320 - 335**	**4.8%**	**390-400**
Funds from operations[3]	**$3.3B**	**9%**	**~$4.8B**
Free cash flow[3]	**$750M**	**12%**	**~$1.2B**
Upstream operating cost/bbl	$14.25		<$12
Downstream refining margins/bbl	$14.75		>$16
Earnings break-even oil price (US WTI)[3]	~$43.60		~$37
Cash break-even oil price (US WTI)[3]	~$33.50		~$32
Ranges and Targets		2017-2021F	
Sustaining capital[3]		Average $1.9B	
Capital expenditures		Average $3.3B	
Average proved reserve replacement ratio		Target >130%	
Net debt to FFO[3]		<2x	

(1) Based on oil price of $50 US WTI in 2017, $55 in 2018, and $60 in 2019 through 2021. AECO priced at $2.50 Cdn in 2017 and $3.00 thereafter
(2) Compound annual growth rate
(3) Non-GAAP measures, refer to advisories

Husky Energy will hold its Investor Day in Toronto today to present a five-year plan expected to grow funds from operations at a compounded rate of nine percent a year.

Husky's plan includes continued cost structure reductions and provides for returns-focused growth.

"We have transformed Husky to grow profitably in this new, lower commodity price era," said CEO Rob Peabody. "With a significantly reduced break-even and one of the strongest balance sheets in the industry, we are set to further develop a deep portfolio of investment opportunities that will allow us to compound returns, generate increased free cash flow and return cash to shareholders."

Under Husky's plan, funds from operations are expected to grow from about $3.3 billion in 2017 to about $4.8 billion in 2021. Free cash flow is expected to grow at a compound annual growth rate of 12 percent, rising from about $750 million in 2017 to about $1.2 billion in 2021.

"Production will increase steadily over our five-year plan, with funds from operations and free cash flow growing at much higher rates as a result of ongoing reductions in our cost structure," added Peabody.

As a result of continued cost efficiencies, capital spending guidance for 2017 has been reduced by $100 million to $2.5 - $2.6 billion.

Husky's Five-Year Plan Highlights:

- 4.8 percent per year production growth, from about 320,000 – 335,000 barrels of oil equivalent per day (boe/day) in 2017 to 390,000 – 400,000 boe/day in 2021, which includes new thermal oil development at Lloyd, the Tucker Thermal Project, Sunrise, and Asia Pacific offshore gas.
- 17 percent lower operating costs (to less than $12 per boe) as a result of ongoing investment in lower-cost, longer-life production.
- Lower sustaining capital requirements per boe – sustaining capital increases at a lower rate than production growth.
- Growing production and fixed-price gas contracts in Asia Pacific deliver strong netbacks with low volatility.
- Higher downstream margins from increased heavy oil processing capacity, expanded asphalt capacity, and product sales flexibility.
- Strong inventory of projects that can deliver at least 10 percent rates of return after tax at $45 US WTI, break even at $35 US WTI.

Two Core Businesses

Husky's go-forward strategy focuses on two core businesses: an integrated Canada-U.S. upstream and downstream corridor and offshore production in the Asia Pacific and Atlantic regions. Both businesses have strong prospects to generate increased free cash flow over the five-year plan, with built-in measures to mitigate volatility.

Integrated Corridor – North American Upstream and Downstream

Husky has a large and growing inventory of heavy oil thermal projects in the Lloydminster region of Saskatchewan and Alberta, as well as the Tucker Thermal Project near Cold Lake and the Sunrise Energy Project north of Fort McMurray. These projects are physically integrated with the Downstream business, which provides for increased margin capture, secured U.S. market access and free cash flow growth.

Thermal bitumen production at the end of 2016 was approximately 120,000 barrels per day (bbls/day), a 55 percent increase since 2015. Husky expects to add 40,000 bbls/day of new thermal bitumen nameplate capacity over the next five years. A 10,000 bbls/day thermal bitumen project is under construction at Rush Lake 2, and three additional 10,000 bbls/day thermal bitumen projects are progressing in Saskatchewan at Dee Valley, Spruce Lake North and Spruce Lake Central. Husky has identified at least 14 additional Lloyd thermal developments for potential advancement.

Tucker thermal bitumen production is currently averaging about 23,000 bbls/day and with new wells being commissioned, production is expected to ramp up towards 30,000 bbls/day in 2018. At Sunrise, gross production is now about 40,000 bbls/day, with 14 new well pairs in the process of being tied-in and placed on production by the end of 2017.

Supporting this thermal growth is Western Canada production, which is now more than 70 percent gas-weighted. This provides a supply and natural hedge for Husky's energy requirements at its thermal projects and refineries.

The final leg of the corridor is Husky's Downstream assets consisting of its storage facilities, Lloydminster Upgrader, asphalt plant and refining capacity in the PADD II district of the U.S. Midwest, which creates processing and marketing options. Husky's five-year plan includes targeted investments to increase feedstock flexibility, optimize the product slate and increase margin capture:

- At the Lloydminster Complex, which includes an Upgrader and an asphalt refinery, engineering is progressing on a proposal to double asphalt processing capacity to 60,000 bbls/day.
- At the Lima, Ohio refinery, the crude oil flexibility project is expected to increase heavy oil processing capacity to 40,000 bbls/day by the end of 2018. It can currently process up to 10,000 bbls/day of heavy crude.
- At the partner-operated Toledo Refinery, upgrades have increased the amount of high-TAN crude that can be processed to 65,000 bbls/day, accommodating volumes from the Sunrise Energy Project. This has improved margins by about $3 US per barrel for Toledo's refinery throughput.

Offshore

Husky currently invests in two offshore production regions – Asia Pacific, offshore China and Indonesia; and Atlantic, offshore Newfoundland and Labrador. Each region provides for high netback production, with robust near-term investment opportunities and the ability to generate immediate free cash flow growth.

Asia Pacific

- Production from the region is expected to grow about 50 percent over the five-year plan to about 60,000 boe/day, reflecting increasing volumes from fixed-price gas projects offshore Indonesia and the Liwan Gas Project.
- First gas sales are expected to begin soon at the BD Gas Project in the Madura Strait, with an expected ramp-up to full sales gas rates during the second half of 2017.
- The MDA-MBH and MDK fields are being developed in tandem and are scheduled for first production in the 2018-2019 timeframe. A plan of development has been approved for the MAC field and additional opportunities are being evaluated.
- The Company recently signed a production sharing contract for Block 16/25 in the Pearl River Mouth Basin offshore China. Two exploration wells are expected to be drilled on the shallow water block in the 2018 timeframe, in conjunction with two other planned exploration wells at nearby Block 15/33.
- Negotiations are progressing on a fixed-price sales agreement for the Liuhua 29-1 field. Project sanction is anticipated in the second half of 2017, subject to a final price agreement.

Atlantic

- Husky and its partners announced they are moving forward with development of the West White Rose Project. The project will use a fixed wellhead platform tied back to the *SeaRose* floating production, storage and offloading (FPSO) vessel, which will enable the Company to maximize resource recovery. First oil is expected in 2022 and the project is anticipated to achieve gross peak production rate of 75,000 bbls/day (52,500 bbls/day Husky working interest) in 2025.
- Infill wells continue to extend the life of the main White Rose field by mitigating natural declines. A new development well was completed at South White Rose in the fourth quarter of 2016. It was followed by a new infill well at North Amethyst in the first quarter of 2017, and an additional infill well at White Rose is expected to be brought on production later in 2017.
- A new discovery has been made in the White Rose production area at Northwest White Rose. The A-78 exploration well was drilled about 11 kilometres northwest of the *SeaRose* FPSO in the first quarter of 2017 and delineated a light oil column of more than 100 metres. The discovery continues to be assessed. Husky has a 93.2 percent ownership interest.

- Drilling has commenced on two additional exploration wells in the Flemish Pass Basin. The Company has a 35 percent working interest in five oil discoveries in the Flemish Pass at Bay du Nord, Mizzen, Harpoon, Bay de Verde and Baccalieu.

2017 Investor Day

Members of Husky's senior management team will meet with investors and analysts today to discuss the Company's five-year plan. Presentations will be webcast and will be available at www.huskyenergy.com

Location: Civic Ballroom, Sheraton Centre Toronto Hotel
123 Queen St. W, Toronto, Ontario

Presentations begin at 10 a.m. Eastern Time. The webcast may be accessed approximately 10 minutes before the scheduled start time. A webcast archive and transcript will be available for 90 days following the presentation.

Husky Energy is a Canadian-based integrated energy company. It is headquartered in Calgary, Alberta, Canada and its common shares are publicly traded on the Toronto Stock Exchange under the symbol HSE. More information is available at www.huskyenergy.com

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FORWARD-LOOKING STATEMENTS

Certain statements in this presentation, including "financial outlook," are forward-looking statements and information (collectively "forward-looking statements") within the meaning of 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 production, funds from operations, free cash flow, upstream operating cost per barrel, downstream refining margins per barrel, earnings break-even oil price and cash break-even oil price by 2021 and range and targets for sustaining capital, capital expenditures, five-year average proved reserve replacement ratio and net debt to funds from operations from 2017 to 2021; forecast production, funds from operations and free cash flow compound annual growth rate from 2017 to 2021; capital spending guidance for 2017; and expected rates of return;

- with respect to the Company's Thermal Developments: expectations regarding the addition of nameplate capacity over the next five years, including at Rush Lake 2, DEE Valley, Spruce Lake North and Spruce Lake Central; expected timing and volume of production ramp-up at Tucker; and expected timing to tie in 14 new well pairs at Sunrise;

- with respect to the Company's Downstream operating segment: plans to increase feedstock flexibility, optimize the product slate and increase margin capture; an expected increase to asphalt capacity at the Lloydminster Complex; and an expected increase to heavy oil processing capacity and timing for such increase at the Lima, Ohio refinery;

- with respect to the Company's Asia Pacific region: expectations regarding production growth and fixed-price gas contracts over the five-year plan; the expected timing of commencement of first sales gas and the expected timing of ramp-up to full gas rates at the BD Gas Project; expected timing of first production at the MDA-MBH and MDK fields; drilling plans for Block 16/25 and Block 15/33; and the anticipated timing for project sanction at Liuhua 29-1; and

- with respect to the Company's Atlantic region: the timing of first production and the timing and volume of gross peak production capacity at West White Rose; timing to bring an additional infill well on production at White Rose; and drilling plans in the Flemish Pass Basin.

Certain of the information in this presentation is “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding the Company’s reasonable expectations as to the anticipated results of its proposed business activities. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

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.

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 management’s assessment of the future considering all information available to it at the relevant time. 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.

NON-GAAP MEASURES

This presentation contains certain terms which do not have any standardized meanings prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. None of these measures 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. The following non-GAAP measures are considered to be useful as complementary measures in assessing Husky's financial performance, efficiency and liquidity:

- "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 the Company's financial reports 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.

- "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.

- "Net debt" is a non-GAAP measure that equals total debt less cash and cash equivalents. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Net debt is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

- "Net debt to funds from operations" is a non-GAAP measure that equals net debt divided by funds from operations. Net debt to funds from operations is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

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

- "Sustaining capital" is the additional development capital that is required by the business to maintain production and operations at existing levels. Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure. Sustaining capital does not have any standardized meaning and therefore 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 Cdn$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. Earnings break-even is used to assess the impact of changes in WTI oil prices on the net earnings of the Company and could impact future investment decisions.

- "Cash 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 Canadian dollars 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. Cash break-even is used to assess the impact of changes in WTI oil prices on the net earnings of the Company and could impact future investment decisions.

DISCLOSURE OF OIL AND GAS INFORMATION

Unless otherwise indicated: (i) projected and historical production volumes provided represent the Company's working interest share before royalties; and (ii) historical production volumes provided are for the year ended December 31, 2016.

The Company uses the term "barrels of oil equivalent" (or "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.

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 thermal bitumen 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 comparison purposes.

The Company uses the term "reserve replacement ratio", which is consistent with other oil and gas companies' disclosures. Reserve replacement ratios for a given period are determined by taking the Company's incremental proved reserves additions for that period divided by the Company's upstream gross production for the same period. The reserve replacement ratio measures the amount of reserves added to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserve replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserve replacement ratio only measures the amount of reserves added to a company's reserves base during a given period.

All currency is expressed in Canadian dollars unless otherwise indicated.