Husky

Q1 NEWS RELEASE

Calgary, Alberta
April 26, 2019

Husky Energy Reports First Quarter 2019 Results

This news release contains references to the non-GAAP financial measures "funds from operations", "free cash flow", "net debt", "net debt to trailing funds from operations", "operating netback" and "EBITDA". Please refer to "Non-GAAP Measures" at the end of this news release.

Husky Energy generated funds from operations of $959 million in the first quarter of 2019, compared to $895 million in the first quarter of 2018. Net earnings were $328 million, compared to $248 million in Q1 2018 and free cash flow was $147 million, compared to $258 million in the first quarter of 2018. Cash flow from operating activities, which includes changes in non-cash working capital, was $545 million, compared to $529 million in Q1 2018.

"We delivered more funds from operations compared to the first quarter of 2018, despite Alberta government quotas on our oil production, and even with global oil prices pretty much on par in Canadian dollar terms," said CEO Rob Peabody.

"The structural transformation of our business over the past several years is paying off. We are now realizing higher per-barrel margins across the Company."

Peabody noted that while Husky's Upstream segment made a strong contribution to funds from operations as a result of tighter Canadian heavy-light differentials, the largest benefit was from U.S. refining margins. "This further demonstrates the value of our Integrated Corridor business," he said. "We can capture value at any point along the Upstream-Downstream chain, resulting in global pricing for most of our production."

Husky further advanced its process safety and asset integrity program in the first quarter with the appointment of Peter Rosenthal as Senior Vice President of Safety and Operations Integrity, reporting directly to the CEO.

FIRST QUARTER HIGHLIGHTS

- Funds from operations of $959 million, up 64% over the previous quarter and 7% higher than Q1 2018
- Cash flow from operating activities of $545 million, compared to $529 million in Q1 2018; the quarter saw an increase in working capital driven by commodity prices, a seasonal increase in inventories and business interruption insurance accruals related to the Superior Refinery
- Net earnings of $328 million, up 52% over the previous quarter and 32% higher than Q1 2018
- Capital spending of $812 million, primarily directed to advancing Lloyd thermal bitumen projects and construction of the West White Rose Project; 2019 capital guidance remains on track
- Free cash flow of $147 million, compared to $258 million in Q1 2018
- Quarterly cash dividend of $0.125 per common share declared
- Net debt of $3.4 billion, representing 0.8 times trailing 12 months funds from operations; senior unsecured notes offering raised $750 million US for general corporate purposes, which may include repaying debt maturing in 2019
- Upstream production of 285,200 barrels of oil equivalent per day (boe/day) compared to 304,300 boe/day in Q4 2018, largely reflecting the impact of mandatory Alberta production quotas and limited production from the White Rose field; 2019 production guidance remains on track

Integrated Corridor

- Downstream throughput of 333,600 barrels per day (bbls/day); including record throughput at the Lima Refinery as a result of efficiencies and optimizations
- Announced plans for the strategic review and potential sale of non-core Downstream assets, including the Company's Canadian retail and commercial fuels business and the Prince George Refinery
- 10,000 bbls/day Dee Valley Lloyd thermal project progressing ahead of schedule, with first oil expected in Q4 2019

- Spruce Lake Central and Spruce Lake North Lloyd thermal projects, representing an aggregate of 20,000 bbls/day, are advancing towards first production in 2020

Offshore

- Production at the White Rose field offshore Newfoundland and Labrador continues to ramp up following a temporary suspension of operations in the fourth quarter of 2018
- Two additional infill wells at the White Rose field are in the process of being tied in and are expected to be placed onto production in the coming days
- Continued strong Asia Pacific operating netbacks of $68.33 per boe

	Three Months Ended		
	Mar. 31 2019	Dec. 31 2018	Mar. 31 2018
Daily production, before royalties			
Total equivalent production (mboe/day)	285	304	300
Crude oil and natural gas liquids (mbbls/day)	199	215	221
Natural gas (mmcf/day)	517	538	477
Upstream operating netback[1,2] ($/boe)	27.69	9.42	24.37
Refinery and Upgrader throughput (mbbls/day)	334	287	398
Cash flow – operating activities ($mm)	545	1,313	529
Funds from operations[1] ($mm)	959	583	895
Per common share – Basic ($/share)	0.95	0.58	0.89
Free cash flow[1] ($mm)	147	(682)	258
Net earnings ($mm)	328	216	248
Per common share – Basic ($/share)	0.32	0.21	0.24
Net debt[3] ($ billions)	3.4	2.9	3.2
Dividend per common share ($/share)	0.125	0.125	0.075

[1]Non-GAAP measure; refer to advisory.
[2]Operating netback includes results from Upstream Exploration and Production and excludes Upstream Infrastructure and Marketing.
[3]Net debt is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt, less cash and cash equivalents. Refer to advisory.

FIRST QUARTER RESULTS

Upstream production averaged 285,200 boe/day, compared to 300,400 boe/day in the first quarter of 2018. This takes into account mandated Alberta government production quotas and the ongoing ramp-up of operations at the White Rose field, which resumed production at the end of January 2019. Production in the Atlantic region averaged 7,600 bbls/day in the quarter compared to 28,400 bbls/day a year ago.

Upstream operating netbacks averaged $27.69 per boe, compared to $24.37 per boe in the first quarter of 2018, reflecting tighter Canadian heavy oil differentials. Average realized pricing for Upstream production was $47.20 per boe, compared to $40.87 per boe in the year-ago period. Realized pricing for oil and liquids averaged $49.14 per barrel, and natural gas averaged $7.12 per thousand cubic feet (mcf).

Upstream operating costs averaged $16.30 per boe, compared to $13.33 per boe in the first quarter of 2018. The increase was due to a combination of factors, including Alberta production quotas, reduced Atlantic volumes as the White Rose field continues its production ramp up, and higher gas and electricity costs in Western Canada.

Total Downstream throughput was 333,600 bbls/day compared to 398,100 bbls/day in Q1 2018, which takes into account the continued suspension of operations at the Superior Refinery.

The Chicago 3:2:1 crack spread averaged $13.08 US per barrel compared to $12.84 US per barrel in Q1 2018.

The average realized U.S. Refining and Marketing margin was $17.64 US per barrel of crude throughput, which reflects a favourable first-in, first-out (FIFO) pre-tax inventory valuation adjustment of $3.91 US per barrel. This compared to $8.51 US per barrel a year ago, which included a favourable FIFO pre-tax inventory valuation adjustment of $0.28 US per barrel.

The Upgrading realized margin was $21.24 per barrel, down from $31.63 per barrel in the year-ago period, largely due to tighter heavy oil differentials.

In the Infrastructure and Marketing segment, EBITDA was $171 million compared to an EBITDA of $190 million in Q1 2018, primarily reflecting the value captured from the Company's long-term committed oil and gas export pipeline capacity and storage assets.

Funds from operations were $959 million, compared to $895 million in the first quarter of 2018. Capital expenditures were $812 million, leading to free cash flow of $147 million. Net earnings were $328 million.

Capital spending included investments in Lloyd thermal projects, the West White Rose Project, the Liuhua 29-1 field development, and the crude oil flexibility project at the Lima Refinery.

INTEGRATED CORRIDOR

- Upstream average production of 231,500 boe/day
- Overall upstream operating netback of $21.03 per boe, compared to $10.91 per boe in Q1 2018
  - $30.89 per barrel netback from thermal operations
- Downstream throughput of 333,600 bbls/day
- Downstream upgrading/refining margin of $22.81 per barrel
- Infrastructure and Marketing realized margin of $167 million

Thermal Production

The government production quota for Husky in Alberta averaged out to be 86,000 bbls/day in the first quarter, which resulted in the shut-in of approximately 20,000 bbls/day of production. Impacts included:

- Production at the Sunrise Energy Project averaged 44,600 bbls/day (22,300 bbls/day Husky working interest) compared to 54,400 bbls/day (27,200 bbls/day Husky working interest) in the fourth quarter of 2018 and 59,000 bbls/day in December 2018 (29,500 bbls/day Husky working interest).
- At Tucker, production averaged 25,000 bbls/day compared to 25,200 bbls/day in the fourth quarter of 2018 and 27,500 bbls/day in December 2018.

Total thermal bitumen production from Lloyd thermal projects, Tucker and Sunrise averaged about 130,300 bbls/day (Husky working interest), compared to 123,200 bbls/day (Husky working interest) in the first quarter of 2018. Overall operating costs at Sunrise, Tucker and 10 producing Lloyd thermal projects were approximately $13.79 per barrel. Costs were up due to higher gas and electricity prices as well as the impacts from the production quota.

Five 10,000 bbls/day Lloyd thermal projects are being advanced through 2022, with a combined design capacity of 50,000 bbls/day. These long-life thermal projects are being phased to optimize capital efficiency and project execution.

- At Dee Valley, first oil is expected in the fourth quarter of 2019
- At Spruce Lake Central, the central processing facility is under construction with first production anticipated in the second half of 2020
- At Spruce Lake North, first oil is planned around the end of 2020
- At Spruce Lake East, first production is expected around the end of 2021
- At Edam Central, first production is anticipated in 2022

The Pikes Peak Lloyd thermal project was shut in in February 2019 and will now be abandoned, after producing 78 million barrels over 36 years of operations.

Resource Plays

In the Ansell and Kakwa areas, eight wells were drilled and six completed, with drilling focusing on liquids rich wells in the Cardium and Spirit River formations. In the liquids-rich Montney formation, three wells were drilled at Wembley and one at Sinclair.

Downstream

Canadian throughput, including the Lloydminster Upgrader and asphalt refinery, averaged 104,200 bbls/day. EBITDA was $157 million.

U.S. refining throughput averaged 229,400 bbls/day, with record refining throughputs at the Lima Refinery following a turnaround in Q4. Throughput at the Lima Refinery averaged 171,400 bbls/day compared to 164,400 bbls/day in the first quarter of 2018. The crude oil flexibility project to increase heavy oil processing capacity from 10,000 bbls/day to 40,000 bbls/day is on pace for the end of 2019.

The U.S. refining segment recorded EBITDA of $341 million, which included $113 million in pre-tax insurance proceeds primarily for business interruption at the Superior Refinery. The refinery rebuilding project is expected to begin this fall, subject to regulatory approvals, with partial operations targeted for late 2020.

OFFSHORE

- Average production of 53,700 boe/day
- Operating netback of $56.28 per boe
    - China operating netback of $72.95 per boe
    - Indonesia operating netback of $48.05 per boe

Asia Pacific

China
Sales gas production from the two producing fields at the Liwan Gas Project averaged 369 million cubic feet per day (mmcf/day), with associated liquids averaging 15,600 bbls/day (181 mmcf/day and 7,700 bbls/day Husky working interest). Realized gas pricing was $14.35 Cdn per mcf, with liquids pricing of $69.11 Cdn per barrel.

At the Liuhua 29-1 field, drilling of three remaining wells is expected to be completed in the second quarter of 2019. Altogether, seven wells will be tied into the existing Liwan infrastructure, with first gas expected around the end of 2020. Target production from this third deepwater field at Liwan is 45 mmcf/day of gas and 1,800 bbls/day of liquids when fully ramped up, reflecting Husky's 75% working interest.

Indonesia
Sales gas production at the liquids-rich BD Project averaged 89 mmcf/day, with liquids production of 5,700 bbls/day (34 mmcf/day and 2,600 bbls/day Husky working interest), reflecting a planned 12-day maintenance completed in the first quarter.

BD production was sold at contracted rates for a realized gas price of $9.88 Cdn per mcf, with liquids pricing of $81.96 Cdn per barrel.

Atlantic

Overall average net production was approximately 7,600 bbls/day. This compares to 28,400 bbls/day in the same period a year ago and reflects the suspension of operations at the White Rose field in November 2018.

White Rose Field Update
Operations resumed at the end of January from the Central Drill Centre at the White Rose field, with production expected to continue ramping up through the second quarter as additional subsea drill centres are brought on stream. Current production from the White Rose field is approximately 5,000 bbls/day, Husky working interest.

Two additional infill wells at the White Rose field are in the process of being tied in and are expected to be placed onto production in the coming days.

West White Rose Project
Construction work on the drilling and wellhead platform, topsides and living quarters continues to progress, with first oil anticipated in 2022.

CORPORATE DEVELOPMENTS

Husky announced the appointment of a new Senior Vice President of Safety and Operations Integrity. Peter Rosenthal reports directly to the CEO and will oversee process and occupational safety, operations integrity and emergency response. He has deep experience in process safety and risk management, with nearly 30 years of industry experience.

During the quarter, Husky raised $750 million US in a senior unsecured notes offering with the proceeds being used for general corporate purposes, which may include, among other things, the repayment of certain outstanding debt securities maturing in 2019.

The Board of Directors has approved a quarterly dividend of $0.125 per common share for the three-month period ended March 31, 2019. The dividend will be payable July 2, 2019 to shareholders of record at the close of business on June 10, 2019.

Regular dividend payments on each of the Cumulative Redeemable Preferred Shares – Series 1, Series 2, Series 3, Series 5 and Series 7 – will be paid for the three-month period ended June 30, 2019. The dividends will be payable on July 2, 2019 to holders of record at the close of business on June 10, 2019.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	3.443	$0.21267
Series 3	Regular	4.50	$0.28125
Series 5	Regular	4.50	$0.28125
Series 7	Regular	4.60	$0.28750

CONFERENCE CALL

A conference call will be held on Friday, April 26 at 8 a.m. Mountain Time (10 a.m. Eastern Time) to discuss Husky's 2019 first quarter results. CEO Rob Peabody, COO Rob Symonds and CFO Jeff Hart will participate in the call.

To listen live:	To listen to a recording (after 9 a.m. MT on April 26):
Canada and U.S. Toll Free: 1-800-319-4610 Outside Canada and U.S.: 1-604-638-5340	Canada and U.S. Toll Free: 1-800-319-6413 Outside Canada and U.S.: 1-604-638-9010 Passcode: 3076 Duration: Available until May 26, 2019 Audio webcast: Available for 90 days at www.huskyenergy.com

Following the conference call, the Company will hold its Annual Meeting of Shareholders at 10:30 a.m. (Mountain Time) in the Performance Hall at Studio Bell, 850 4th Street S.E., Calgary, Alberta.

A live webcast of the meeting will be available at www.huskyenergy.com under Investor Relations. The archived webcasts of the conference call and the meeting will be available for approximately 90 days.

Investor and Media Inquiries:

Leo Villegas, Senior Manager, Investor Relations
403-513-7817

Mel Duvall, Senior Manager, Media & Issues
403-513-7602

FORWARD-LOOKING STATEMENTS

Certain statements in this news release 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 news release 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", "scheduled" and "outlook"). In particular, forward-looking statements in this news release include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: general strategic plans and growth strategies; production guidance remaining on track; and the use of proceeds of the senior unsecured notes offering;

- with respect to the Company's thermal developments, estimated production and expected timing of first production from the Dee Valley, Spruce Lake Central, Spruce Lake North, Spruce Lake East and Edam Central projects;

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of drilling of the remaining three wells at, and first gas production from, Liuhua 29-1; and target production from Liuhua 29-1 when fully ramped up.

- with respect to the Company's Offshore business in Atlantic: expectations regarding the ramp-up of production at the White Rose field; expected timing for two additional infill wells at the White Rose field to be placed onto production; and the expected timing of first oil at the West White Rose Project; and

- with respect to the Company's Downstream operations: the potential sale of non-core Downstream assets; the expected timing of completion of the crude oil flexibility project at the Lima Refinery; the expected timing of commencement of the rebuild of the Superior Refinery; and the expected timing of resumption of partial operations at the Superior Refinery.

There are numerous uncertainties inherent in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this news release 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 and regulators, among others.

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 the Company.

The Company's Annual Information Form for the year ended December 31, 2018 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe some of the 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 news release contains references to the terms "funds from operations", "free cash flow", "net debt", "net debt to trailing funds from operations", "operating netback" and "EBITDA". None of these measures is used to enhance the Company's reported financial performance or position. These measures are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. With the exception of funds from operations, free cash flow and net debt, there are no comparable measures to these non-GAAP measures under IFRS.

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 of the Company in the stated period. Funds from operations equals cash flow – operating activities plus 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 to assist management and investors in analyzing operating performance by the business in the stated period. Free cash flow equals funds from operations less capital expenditures.

Free cash flow was restated in the fourth quarter of 2018 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of investment in joint ventures. Prior periods have been restated to conform to current presentation.

The following table shows the reconciliation of net earnings (loss) to funds from operations and free cash flow, and related per share amounts, for the periods indicated:

	Three months ended		
($ millions)	Mar. 31 2019	Dec. 31 2018	Mar. 31 2018
Net earnings	328	216	248
Items not affecting cash:			
Accretion	27	25	24
Depletion, depreciation, amortization and impairment	630	662	618
Inventory write-down to net realizable value	-	60	-
Exploration and evaluation expenses	-	22	-
Deferred income taxes	43	25	77
Foreign exchange loss (gain)	(12)	1	1
Stock-based compensation	7	(50)	21
Gain on sale of assets	(2)	-	(4)
Unrealized mark to market loss (gain)	57	(16)	(86)
Share of equity investment gain	(22)	(16)	(9)
Gain on insurance recoveries for damage to property	-	(253)	-
Other	(9)	2	2
Settlement of asset retirement obligations	(72)	(65)	(49)
Deferred revenue	(16)	(30)	(20)
Distribution from joint ventures	-	-	72
Change in non-cash working capital	(414)	730	(366)
Cash flow - operating activities	545	1,313	529
Change in non-cash working capital	414	(730)	366
Funds from operations	959	583	895
Capital expenditures	(812)	(1,265)	(637)
Free cash flow	147	(682)	258
Weighted average number of common shares outstanding	1,005.1	1,005.1	1,005.1
Funds from operations			
Per common share - Basic ($/share)	0.95	0.58	0.89

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

The following table shows the reconciliation of net debt as at the dates indicated:

	Mar. 31	Dec. 31	Mar. 31
($ millions)	2019	2018	2018
Short-term debt	200	200	200
Long-term debt due within one year	1,803	1,433	-
Long-term debt	4,661	4,114	5,343
Cash and cash equivalents	(3,245)	(2,866)	(2,301)
Net debt	3,419	2,881	3,242

Net debt to trailing funds from operations is a non-GAAP measure that equals net debt divided by the 12-month trailing funds from operations as at March 31, 2019. Net debt to trailing 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 measure used in the oil and gas industry. Management believes 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 gross revenue less royalties, production and operating and transportation costs on a per unit basis.

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 IFRS, as an indicator of financial performance. EBITDA is presented 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.

DISCLOSURE OF OIL AND GAS INFORMATION

Unless otherwise indicated: (i) projected and historical production volumes provided are gross, which represents the total or the Company's working interest share, as applicable, before deduction of royalties; (ii) all Husky working interest production volumes quoted are before deduction of royalties; and (iii) historical production volumes provided are for the year ended December 31, 2018.

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.

All currency is expressed in Canadian dollars unless otherwise indicated.