Husky

Q4 NEWS RELEASE
Calgary, Alberta
February 27, 2020

Husky Energy Reports 2019 Fourth Quarter and Annual Results

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

Husky Energy generated funds from operations of $3.3 billion in 2019, including $469 million in the fourth quarter. Cash flow from operating activities, including changes in non-cash working capital, was $3 billion in 2019, including $866 million in the fourth quarter.

Fourth quarter operating results were negatively impacted by several factors, including:

- Lower U.S. crack spreads and an extended shutdown of the Lima Refinery to complete the crude oil flexibility project
- Lower Infrastructure and Marketing margins compared to Q4 2018, primarily due to narrower location differentials, and an outage on the Keystone pipeline in November, which impacted Husky's ability to capture the differential
- Severance costs related to staff reductions

"We delivered on critical milestones during the year, including our top priority of improved safety performance," said CEO Rob Peabody. "We met our production and capital guidance, achieved first oil at the 10,000 barrel-per-day Dee Valley thermal bitumen project and have completed the safe startup of the Lima Refinery crude oil flexibility project."

In the fourth quarter, Husky recognized asset impairment and other charges of $2.3 billion (after tax), largely related to long-term price assumptions and reductions in the Company's long-term capital expenditure plans.

The Board of Directors has approved a quarterly dividend of $0.125 per common share for the three-month period ended December 31, 2019. The dividend will be payable on April 1, 2020 to shareholders of record at the close of business on March 17, 2020.

2019 ACHIEVEMENTS

- No major safety incidents, more than 50% reduction in lost-time injuries and Tier 1 process safety events
- Production within guidance at 290,000 barrels of oil equivalent per day (boe/day)
- Capital expenditures within guidance at $3.4 billion, including the Superior Refinery rebuild capital
- Project execution included the startup of the 10,000 barrel-per-day Dee Valley thermal bitumen project ahead of schedule, the completion of the Lima Refinery crude oil flexibility project and the sale of the Prince George Refinery
- Annual average production from Lloydminster thermal bitumen projects, Sunrise and Tucker of 128,800 barrels per day (bbls/day), Husky working interest (W.I.), compared to annual average production of 124,200 bbls/day in 2018 (Husky W.I.); takes into account impacts of the government-mandated production quotas in Alberta
- Average gross natural gas and liquids production at the Liwan Gas Project of 73,200 boe/day (35,900 boe/day Husky W.I.)
- Completed fourth quadrant of the concrete gravity base at the West White Rose Project ahead of schedule; project now 57% complete with first oil planned for around the end of 2022
- Dividends declared during the year totalled $0.50 per common share. In 2019, the Company returned $503 million in cash payments to shareholders, up from $276 million in 2018

FOURTH QUARTER RESULTS

- Funds from operations of $469 million, compared to $583 million in the year-ago period; reflects lower U.S. crack spreads, the extended shutdown at the Lima Refinery, lower Infrastructure and Marketing margins and $74 million related to employee severance. The operating margin at the Lima Refinery was negative $129 million, reflecting impacts from the shutdown to complete the crude oil flexibility project
- Cash flow from operating activities, including changes in non-cash working capital, of $866 million, compared to $1.3 billion in the fourth quarter of 2018
- Net loss of $2.3 billion, compared to net earnings of $216 million in Q4 2018, reflecting fourth quarter after-tax impairments. Net earnings excluding impairments, write-downs and the asset de-recognition were $5 million
- Capital spending of $894 million, including Superior Refinery rebuild capital; primarily directed towards advancing the growing Saskatchewan thermal portfolio and progressing construction of the Liuhua 29-1 field offshore China and the West White Rose Project in the Atlantic region
- Net debt of $3.7 billion, including proceeds from the sale of the Prince George Refinery; total liquidity (cash and unused credit facilities) of $5.7 billion
- Overall Upstream production of 311,300 boe/day, compared to 304,300 boe/day in Q4 2018; takes into account ongoing mandated production quotas in Alberta
- Downstream throughput of 203,400 bbls/day, compared to 286,900 bbls/day in Q4 2018; reflects the extended shutdown of the Lima Refinery

FOURTH QUARTER IMPAIRMENTS & OTHER IMPACTS

Total non-cash asset impairments and other charges were $2.3 billion (after tax) in the fourth quarter of 2019. These were primarily related to the Company's upstream assets in North America, including the Sunrise Energy Project and the Atlantic and Western Canada segments, and were largely due to lower long-term commodity price assumptions and a reduction in future capital spending. The reduction in future capital spending has the effect of reducing reserves, which in turn reduces asset values. Other charges included exploration-related write-downs and asset de-recognition at the Lima Refinery associated with redundant equipment following the completion of the crude oil flexibility project.

RESULTS

	Three Months Ended			Twelve Months Ended	
	Dec. 31 2019	Sept. 30 2019	Dec. 31 2018	Dec. 31 2019	Dec. 31 2018
Upstream production, before royalties					
Crude oil (mbbls/day)	204	189	190	184	192
Natural gas liquids (mbbls/day)	23	22	25	23	23
Conventional natural gas (mmcf/day)	507	503	538	501	507
Total equivalent production[1] (mboe/day)	311	295	304	290	299
Upgrader and refinery throughput (mbbls/day)	203	356	287	308	347
Revenue, net of royalties ($mm)	4,793	5,313	4,992	19,983	22,252
Operating margin[2] ($mm)	656	976	605	3,746	4,515
Integrated Corridor	293	710	334	2,650	3,108
Offshore	363	266	271	1,096	1,407
Funds from operations[2] ($mm)	469	1,021	583	3,251	4,004
Per common share – Basic ($/share)	0.47	1.02	0.58	3.23	3.98
Cash flow – operating activities ($mm)	866	800	1,313	2,971	4,134
Capital expenditures[3] ($mm)	894	868	1,265	3,432	3,578
Free cash flow[2] (loss) ($mm)	(425)	153	(682)	(181)	426
Net earnings (loss) ($mm)	(2,341)	273	216	(1,370)	1,457
Per common share – Basic ($/share)	(2.34)	0.26	0.21	(1.40)	1.41
Net debt[2] ($ billions)	3.7	3.9	2.9	3.7	2.9
Net debt to trailing funds from operations[2] (times)	1.2	1.1	0.7	1.2	0.7

[1]Refer to advisory for full product breakdown.
[2]Non-GAAP measure; refer to advisory.
[3]Including Superior Refinery rebuild costs of $48 million in Q4 2019 and $113 million in 2019; expected to be largely covered by insurance.

Average realized pricing for Upstream production was $46.06 per boe compared to $25.47 per boe in the same period in 2018. Realized pricing for oil and liquids averaged $47.52 per barrel compared to $18.93 per barrel in Q4 2018, and natural gas pricing averaged $7.02 per thousand cubic feet (mcf), compared to $6.86 per mcf in the year-ago period.

Upstream operating costs were $15.25 per boe compared to $13.75 per boe in Q4 2018, primarily due to higher energy and transportation costs, and lower production.

Upstream operating netbacks averaged $27.48 per boe compared to $9.42 per boe in the year-ago period.

Upgrader and refinery throughput was 203,400 bbls/day, compared to 286,900 bbls/day in the same period in 2018. This takes into account an extended turnaround at the Lima Refinery to complete the crude oil flexibility project.

The Chicago 3:2:1 crack spread averaged $12.06 US per barrel compared to $13.38 US per barrel in Q4 2018. The average realized U.S. refining and marketing margin was $7.85 US per barrel of crude oil throughput, which reflects an unfavourable first-in, first-out (FIFO) pre-tax inventory valuation adjustment of $0.24 US per barrel. This compared to $9.12 US per barrel a year ago, which included an unfavourable FIFO pre-tax inventory valuation adjustment of $8.51 US per barrel.

The Upgrader realized margin was $20.21 per barrel compared to $29.13 per barrel in the same period in 2018, which takes into account narrower light-heavy differentials.

The operating margin in the Infrastructure and Marketing segment was $12 million compared to $175 million in Q4 2018, largely due to narrower location differentials and the outage in November on the Keystone pipeline.

Q4 INTEGRATED CORRIDOR

- Average Upstream production of 241,600 boe/day, compared to 240,100 boe/day in Q4 2018
- Operating margin of $293 million, compared to $334 million in the fourth quarter of 2018
- Downstream throughput of 203,400 bbls/day, compared to 286,900 bbls/day in Q4 2018

Thermal Production

Combined average thermal bitumen production from Lloydminster thermal projects, the Tucker Thermal Project and the Sunrise Energy Project was 137,800 bbls/day (Husky W.I.), which takes into account extended production quotas in Alberta, compared to 132,900 bbls/day (Husky W.I.) in Q4 2018. Overall production from the Lloyd thermal portfolio averaged 88,300 bbls/day compared to 80,500 bbls/day in the year-ago period, with an average of 92,000 bbls/day in December.

Five new Saskatchewan thermal bitumen projects with a combined nameplate capacity of 50,000 bbls/day are being advanced through 2023. The Spruce Lake Central project is 92% complete, with startup expected by mid-year 2020. The Spruce Lake North project is 60% complete, with first oil planned around the end of 2020.

Downstream

U.S. refinery throughput averaged 91,700 bbls/day, compared to 179,100 bbls/day in the year-ago period.

The Lima Refinery average throughput was 21,400 bbls/day, which takes into account an extended shutdown to complete the crude oil flexibility project. This, along with lower crack spreads, contributed to an overall negative operating margin of $169 million for the U.S. refining segment, compared to an operating margin of $45 million in the year-ago period.

The Superior Refinery rebuild is under way with a return to full operations expected in 2021. Rebuild costs are expected to be substantially covered by property damage insurance. Pre-tax business interruption insurance recovery in the fourth quarter was $116 million. Insurance recovery related to the rebuild (not included in funds from operations) was $194 million.

Canadian throughput, including the Upgrader, Asphalt Refinery and Prince George Refinery, averaged 111,700 bbls/day. A project to increase diesel production at the Upgrader from 6,000 bbls/day to nearly 10,000 bbls/day is expected to be completed in the second quarter. The Upgrader captured margins of $20.21 per barrel.

The operating margin for the combined Upgrading and Canadian Refined Products segments was $126 million. The overall Downstream operating margin was negative $43 million, compared to a positive operating margin of $296 million in Q4 2018.

A strategic review of the potential sale of the Canadian retail and commercial fuels business continues to progress.

Resource Plays

The Company continues to pace investment in its liquids-rich resource play business in Western Canada with an ongoing focus on lowering costs, optimizing production rates and reducing cycle times while supplying natural gas to its thermal operations. In the Montney Formation, six liquids-rich wells at Wembley were started up in the fourth quarter.

Q4 OFFSHORE

- Average production of 69,700 boe/day, compared to 64,200 boe/day in the fourth quarter of 2018
- Operating netback of $61.00 per boe
    - Asia Pacific operating netback of $69.12 per boe
    - Atlantic operating netback of $45.92 per barrel

Asia Pacific

China
Gross natural gas sales from the two producing fields at the Liwan Gas Project in the fourth quarter averaged 374 million cubic feet per day (mmcf/day), with associated liquids averaging 16,400 bbls/day (183 mmcf/day and 8,300 bbls/day Husky W.I.). Realized gas pricing at Liwan was $14.31 per mcf, with liquids pricing of $67.87 per barrel. Operating costs were $5.16 per boe, with an operating netback of $71.85 per boe.

At the Liuhua 29-1 field at Liwan, all seven wells have been drilled and completed. The wells will be tied into the existing subsea infrastructure, with first gas expected by the end of 2020. Target production is 45 mmcf/day of gas and 1,800 bbls/day of liquids when fully ramped up, reflecting Husky's 75% working interest.

Indonesia
Gross natural gas sales at the BD Project in the Madura Strait averaged 66 mmcf/day, with associated liquids production of 5,100 bbls/day (27 mmcf/day and 2,100 bbls/day Husky W.I.), which takes into account reduced volumes due to temporary processing constraints on the contracted floating production, storage and offloading (FPSO) vessel. Realized gas pricing at BD was $9.85 per mcf, with liquids pricing of $90.33 per barrel. Operating costs were $8.82 per boe, with an operating netback of $51.53 per boe.

Atlantic

Overall average production in the Atlantic region was approximately 24,400 bbls/day (Husky W.I.). This takes into account the suspension of production-related operations in the fourth quarter on the partner-operated *Terra Nova* FPSO, in which Husky has a 13% working interest.

West White Rose Project
The final quadrant of the concrete gravity base was completed ahead of schedule and related topsides construction was progressed as the project advances on plan towards first oil around the end of 2022.

2019 RESERVES REPLACEMENT

The proved reserves life index was 13.5 years, comparable to 2018.

Total proved reserves before royalties at the end of 2019 were 1.43 billion boe, compared to 1.47 billion boe at the end of 2018. Proved plus probable reserves were 2.11 billion boe, compared to 2.54 billion boe at the end of 2018, which reflects reduced future capital spending at the Sunrise Energy Project and the Ansell natural gas resource play in Western Canada in the five-year plan.

Proved reserves additions of 174 million boe were primarily related to Lloydminster thermal projects, the Tucker Thermal Project, and the liquids-rich gas resource play at Wembley. These additions were partially offset by a 5 million boe reduction due to economic factors, and 103 million boe of negative technical revisions across the Company mainly associated with lower future capital spending in the five-year plan. Taking the additions and negative revisions into account, the one-year proved reserves replacement ratio was 67%, excluding economic factors (62% including economic factors).

The average three-year annual proved reserves replacement ratio was 166%, excluding economic factors (162% including economic factors), including dispositions in Western Canada of 62 million boe of proved reserves in 2017.

NEAR & MID-TERM MILESTONES

2020	Capacity (Husky W.I.)	Timing/ Completion	Status (Feb. 27)
Strategic review of fuels/retail business			In progress
Lloyd Upgrader diesel capacity increase	6,000 –> 9,800 bbls/day	Q2	68% complete
Spruce Lake Central thermal project	10,000 bbls/day	Mid-Year	92% complete
Spruce Lake North thermal project	10,000 bbls/day	~YE	60% complete
Liuhua 29-1 project	45 mmcf/day gas 1,800 bbls/day liquids	Q4	80% complete
2021+	**Capacity (Husky W.I.)**	**Timing/ Completion**	**Status (Feb. 27)**
Superior Refinery rebuild	50,000 bbls/day	’21	In progress
Spruce Lake East thermal project	10,000 bbls/day	~YE ’21	15% complete
MDA-MBH & MDK fields	10,000 boe/day	’21	In progress
Edam Central thermal project	10,000 bbls/day	’22	5% complete
West White Rose Project start up	52,500 bbls/day	~YE ’22	57% complete
Dee Valley 2 thermal project	10,000 bbls/day	’23	In planning

CORPORATE DEVELOPMENTS

The Board of Directors has approved a quarterly dividend of $0.125 per common share for the three-month period ended December 31, 2019. The dividend will be payable on April 1, 2020 to shareholders of record at the close of business on March 17, 2020.

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 March 31, 2020. The dividends will be payable on March 31, 2020 to holders of record at the close of business on March 17, 2020.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	3.382	$0.21022
Series 3	Regular	4.689	$0.29306
Series 5	Regular	4.50	$0.28125
Series 7	Regular	4.60	$0.28750

CONFERENCE CALL

A conference call will be held on Thursday, February 27 at 9 a.m. Mountain Time (11 a.m. Eastern Time) to discuss Husky's 2019 fourth quarter and annual results. CEO Rob Peabody, COO Rob Symonds and CFO Jeff Hart will participate in the call.

To listen live:

Canada and U.S. Toll Free: 1-800-319-4610
Outside Canada and U.S.: 1-604-638-5340

To listen to a recording (after 10 a.m. MT on Feb. 27):

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 3994
Duration: Available until March 27, 2020
Audio webcast: Available for 90 days at www.huskyenergy.com

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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;

- with respect to the Company's thermal production in the Integrated Corridor, the expected timing of completion of the Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central and Dee Valley 2 projects;

- with respect to the Company's downstream operations in the Integrated Corridor: the expected timing of resumption of full operations at the Superior Refinery and expected insurance recoveries related to the rebuild costs; the expected timing of completion of the Lloydminster Upgrader diesel capacity project, and the expected increase in diesel production resulting therefrom; and the potential sale of the Canadian retail and commercial fuels business; and

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of first gas at Liuhua 29-1; target production volumes at Liuhua 29-1 when fully ramped up; and the expected timing for production at MDA-MBH & MDK fields and production amounts therefrom; and

- with respect to the Company's Offshore business in Atlantic, expected timing of first oil at the West White Rose Project.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves 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 reserves and 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, 2019 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", "operating margin", "net debt", "net debt to trailing funds from operations" and "operating netback". 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, net debt and operating margin, 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 excluding 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 to funds from operations and free cash flow, and related per share amounts, for the periods indicated:

	Three months ended			**Twelve months ended**	
($ millions)	**Dec. 31 2019**	**Sept. 30 2019**	**Dec. 31 2018**	**Dec. 31 2019**	**Dec. 31 2018**
Net earnings (loss)	(2,341)	273	216	(1,370)	1,457
Items not affecting cash:					
Accretion	27	26	25	106	97
Depletion, depreciation, amortization and impairment	3,520	703	662	5,496	2,591
Inventory write-down to net realizable value	15	-	60	15	60
Exploration and evaluation expenses	332	-	22	355	29
Deferred income taxes	(789)	22	25	(974)	396
Foreign exchange gain	(11)	(1)	1	(26)	(6)
Stock-based compensation	(13)	(9)	(50)	(2)	44
Gain on sale of assets	(3)	(3)	-	(8)	(4)
Unrealized mark to market loss (gain)	(13)	4	(16)	44	(150)
Share of equity investment gain	5	(19)	(16)	(59)	(69)
Gain on insurance recoveries for damage to property	(194)	(13)	(253)	(207)	(253)
Other	11	5	2	12	21
Settlement of asset retirement obligations	(90)	(73)	(65)	(276)	(181)
Deferred revenue	(14)	(7)	(30)	(42)	(100)
Distribution from equity investment	27	113	-	187	72
Change in non-cash working capital	397	(221)	730	(280)	130
Cash flow - operating activities	866	800	1,313	2,971	4,134
Change in non-cash working capital	(397)	221	(730)	280	(130)
Funds from operations	469	1,021	583	3,251	4,004
Capital expenditures	(894)	(868)	(1,265)	(3,432)	(3,578)
Free cash flow	(425)	153	(682)	(181)	426
Weighted average number of common shares outstanding	1,005.1	1,005.1	1,005.1	1,005.1	1,005.1
Funds from operations					
Per common share - Basic ($/share)	0.47	1.02	0.58	3.23	3.98

Operating margin is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, “revenue, net of royalties” as determined in accordance with IFRS, as an indicator of financial performance. Operating margin is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Operating margin equals revenues net of royalties less purchases of crude oil and products, production, operating and transportation expenses, and selling general and administrative expenses.

The following table shows the reconciliation of operating margin for the periods indicated:

	Three months ended								
	Dec. 31, 2019			Sept. 30, 2019			Dec 31, 2018		
($ millions)	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total
Revenue, net of royalties	4,830	452	5,282	5,488	362	5,850	4,781	384	5,165
Less:									
Purchases of crude oil and products	3,733	-	3,733	4,043	-	4,043	3,766	-	3,766
Production and operating expenses	709	87	796	638	88	726	600	103	703
Selling, general and administrative expenses	95	2	97	97	8	105	81	10	91
Operating margin	293	363	656	710	266	976	334	271	605

	Twelve months ended					
	Dec. 31, 2019			Dec 31, 2018		
($ millions)	Integrated Corridor	Offshore	Total	Integrated Corridor	Offshore	Total
Revenue, net of royalties	20,541	1,464	22,005	22,033	1,773	23,806
Less:						
Purchases of crude oil and products	14,839	-	14,839	16,109	-	16,109
Production and operating expenses	2,678	341	3,019	2,478	327	2,805
Selling, general and administrative expenses	374	27	401	338	39	377
Operating margin	2,650	1,096	3,746	3,108	1,407	4,515

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:

($ millions)	**Dec. 30 2019**	**Sept. 30 2019**	**Dec. 31 2018**
Short-term debt	550	200	200
Long-term debt due within one year	400	1,393	1,433
Long-term debt	4,570	4,635	4,114
Cash and cash equivalents	(1,775)	(2,362)	(2,866)
Net debt	3,745	3,866	2,881

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 December 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.

DISCLOSURE OF OIL AND GAS INFORMATION

Unless otherwise indicated: (i) reserves estimates 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, 2019 and represent the Company's working interest share; (ii) 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; and (iii) all Husky working interest production volumes quoted are before deduction of royalties.

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 following table provides the full product breakdown for Upstream production, before royalties, for the periods indicated:

	Three Months Ended			Twelve Months Ended	
	Dec. 31 2019	Sept. 30 2019	Dec. 31 2018	Dec. 31 2019	Dec. 31 2018
Upstream production, before royalties					
Light crude oil & medium (mbbls/day)	33	31	23	25	31
Heavy crude oil (mbbls/day)	33	32	34	30	37
Bitumen (mbbls/day)	138	126	133	129	124
Natural gas liquids (mbbls/day)	23	22	25	23	23
Conventional natural gas (mmcf/day)	507	503	538	501	507
Total equivalent production (mboe/day)	311	295	304	290	299

The Company uses the term "proved reserves life index", which is consistent with other oil and gas companies' disclosures. The Company's proved reserves life index for a given period is determined by taking the Company's total proved reserves at the end of that period divided by the Company's upstream gross production for the same period. Readers are cautioned that the term proved reserves life index may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not reflect the actual life of the reserves.

The Company uses the term "reserves replacement ratio", which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserve additions for that period divided by the Company's upstream gross production for the same period. The reserves 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 reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserves base during a given period. Reserves replacement ratios presented as excluding economic factors exclude the impact that changing oil and gas prices, inflation and regulations have on reserves amounts.

All currency is expressed in Canadian dollars unless otherwise indicated.