Husky Energy

Q4 NEWS RELEASE

Calgary, Alberta
March 1, 2018

Husky Energy Establishes Cash Dividend; Reports Fourth Quarter 2017 and Annual Results

Husky Energy has established a quarterly cash dividend of $0.075 per common share.

Funds from operations were more than $1 billion in the fourth quarter and free cash flow was $294 million, excluding acquisitions and dispositions. Annual funds from operations were $3.3 billion, up 50 percent year over year, and free cash flow was $1.1 billion, up 120 percent over 2016.

Net earnings in the fourth quarter were $672 million, including the benefit of the changes to the U.S. tax rate. Adjusted net earnings for the full year were $882 million.

"We have met or exceeded the targets for the first year of our five-year plan," said CEO Rob Peabody. "The work undertaken by the Company to lower its cost structure, reinforce its strong balance sheet and set the stage for more high-return production growth has unlocked significant value.

"Ongoing investments in higher return projects along our Integrated Corridor and Offshore businesses have positioned us to build on eight quarters of steadily improving funds from operations and free cash flow. At the same time, the physical integration of our Upstream and Downstream assets largely eliminates exposure to widening Canadian heavy oil differentials. Our large U.S. refining business will also benefit from changes to the U.S. tax code on an ongoing basis."

	2017					2016				
	FY	Q4	Q3	Q2	Q1	FY	Q4	Q3	Q2	Q1
Funds from operations[1] ($mm)	3,306	1,039	891	715	661	2,198	662	619	505	412
Free cash flow[1,2] ($mm)	1,086	294	380	135	277	493	271	310	(90)	2
Adjusted net earnings[1] (loss) ($mm)	882	665	136	10	71	(655)	(6)	(100)	(91)	(458)
Net earnings (loss) ($mm)	786	672	136	(93)	71	922	186	1,390	(196)	(458)
Net debt[1] ($B)	2.9	2.9	3.0	3.5	3.8	4.0	4.0	4.1	6.3	7.0

[1]*Non-GAAP measure; refer to advisory.*
[2]*Excludes acquisitions and dispositions.*

FOURTH QUARTER HIGHLIGHTS

- Q4 funds from operations of $1 billion; 2017 funds from operations of $3.3 billion
- Q4 free cash flow of $294 million; 2017 free cash flow of $1.1 billion
- Benefits from recent changes to U.S. tax policy include deferred tax contribution of $436 million to Q4 net earnings; the change is expected to improve future net earnings from the U.S. business and result in future reductions in cash taxes
- Record Downstream throughputs of 387,100 barrels per day (bbls/day) compared to 350,600 bbls/day in the fourth quarter of 2016; Downstream EBITDA of $471 million, up 107 percent from $228 million in Q4 2016
- Completed acquisition of Superior Refinery in the U.S. Midwest

- Record sales gas volumes at the Liwan Gas Project of 361 million cubic feet per day (mmcf/day, 177 mmcf/day Husky working interest) and ramp-up of the liquids-rich BD Project in Indonesia contributed to an Asia Pacific operating netback of $65.31 per barrel of oil equivalent (boe)
- Sanctioned Liuhua 29-1, the third deepwater gas field at the Liwan Gas Project; first production anticipated in 2021
- 60,000 bbls/day of Lloydminster thermal bitumen production in development; includes sanction of 10,000 bbls/day Westhazel and Edam Central Lloyd thermal projects
- Completed the disposition of legacy Western Canada assets at the end of 2017, representing 17,600 boe/day; total asset sales of 52,100 boe/day since late 2015
- Upstream average operating costs of $13.20 per boe, compared to $13.92 per boe in the fourth quarter of 2016; thermal operating costs of $9.83 per barrel compared to $12.30 per barrel in Q4 2016
- Net debt of $2.9 billion, representing less than one times 2017 funds from operations
- 2017 proved reserves replacement ratio of 167 percent, excluding economic factors

	Three Months Ended			Twelve Months Ended	
	Dec. 31 2017	Sept. 30 2017	Dec. 31 2016	Dec. 31 2017	Dec. 31 2016
Daily production, before royalties					
Total equivalent production (mboe/day)	320	318	327	323	321
Crude oil and NGLs (mbbls/day)	231	224	235	233	229
Natural gas (mmcf/day)	535	563	555	539	556
Upstream operating netback[1,2] ($/boe)	30.00	23.25	22.32	25.25	16.19
Refinery and Upgrader throughputs (mbbls/day)	387	374	351	361	310
Funds from operations[1] ($mm)	1,039	891	662	3,306	2,198
Per common share – Basic ($/share)	1.03	0.89	0.66	3.29	2.19
Adjusted net earnings[1] (loss) ($mm)	665	136	(6)	882	(655)
Per common share – Basic ($/share)	0.66	0.14	(0.01)	0.88	(0.65)
Net earnings (loss) ($mm)	672	136	186	786	922
Per common share – Basic ($/share)	0.66	0.13	0.19	0.75	0.88
Dividend per common share[3] ($/share)	0.075	0.00	0.00	0.075	0.00

[1]*Non-GAAP measure; refer to advisory.*
[2]*Operating netback includes results from Upstream Exploration and Production and excludes Upstream Infrastructure and Marketing.*
[3]*Quarterly cash dividend of $0.075 Cdn per common share approved for three-month period ended Dec. 31, 2017; payable April 2, 2018.*

Upstream production averaged 320,400 boe/day, compared to 327,000 boe/day in the fourth quarter of 2016. The decrease reflects the disposition of 20,200 boe/day of legacy assets in Western Canada since the end of the fourth quarter of 2016, partially offset by record production at the Liwan Gas Project and the ramp-up of the liquids-rich BD Project in Indonesia. It also takes into account the expiration of the Wenchang Production Sharing Contract (PSC) in November 2017, which had average production of 2,600 bbls/day in the fourth quarter (Husky working interest). The sale of the Ram River gas processing facility and associated assets was completed in December 2017.

Average realized pricing for Upstream production was $46.69 per boe, compared to $39.90 per boe in the fourth quarter of 2016. Upstream operating costs averaged $13.20 per boe compared to $13.92 per boe in Q4 2016. Upstream operating netbacks averaged $30 per boe compared to $22.32 per boe in the fourth quarter of 2016.

Total Downstream throughputs were 387,100 bbls/day, compared to 350,600 bbls/day in the fourth quarter of 2016.

U.S. refining throughputs were 267,500 bbls/day, including the newly acquired Superior Refinery, and Canadian upgrading and refining throughputs were 119,600 bbls/day. With U.S. refinery utilization averaging 92 percent and increased U.S. heavy oil refining and storage capacity, Husky was shielded from widening heavy oil differentials in the fourth quarter.

The Chicago 3:2:1 crack spread averaged $20.28 US per barrel compared to $10.59 US per barrel in the year-ago period. Average realized U.S. refining margins were $14.71 US per barrel, which takes into account a pre-tax FIFO adjustment gain of $2.40 US per barrel. This compared to $9.86 US per barrel a year ago, which included a pre-tax FIFO adjustment gain of $1.43 US per barrel.

Upgrading net earnings were $48 million, compared to $32 million in Q4 2016. Upgrading margins were $20.65 per barrel, compared to $18.85 per barrel in Q4 2016.

Funds from operations were $1.04 billion, compared to $662 million in the fourth quarter of 2016.

Capital expenditures were $745 million, excluding the acquisition of the Superior Refinery, leading to free cash flow of $294 million. Net earnings were $672 million, which take into account a deferred tax recovery of approximately $436 million Cdn as a result of new U.S. tax law changes.

INTEGRATED CORRIDOR

- Upstream average production of 242,900 boe/day
- Upstream operating netback of $19.59 per boe, including a netback of $30.24 per barrel from thermal operations
  - Average realized price of $35.22 per barrel for liquids
  - Average operating cost of $13.07 per barrel for liquids
- Downstream upgrading/refining margin of $18.06 per barrel
  - Average realized refined product price of $84.87 per barrel
  - Average upgrading/refining operating cost of $6.37 per barrel

Thermal Production

Thermal bitumen production from Lloyd heavy oil thermal projects, the Tucker Thermal Project and the Sunrise Energy Project averaged 120,900 bbls/day (Husky working interest), compared to 115,300 bbls/day in the fourth quarter of 2016. Overall thermal operating costs were $9.83 per barrel.

The Company is currently developing six 10,000 barrel-per-day Lloyd thermal bitumen projects, representing a combined design capacity of 60,000 bbls/day.

- At Rush Lake 2, construction of the Central Processing Facility is progressing ahead of schedule. Twelve well pairs have been completed, with first oil anticipated in the first quarter of 2019.
- At Dee Valley, construction is expected to begin in the second quarter of 2018, with first oil expected in the first half of 2020. Site clearing is currently under way at Spruce Lake North and Spruce Lake Central, which are scheduled to start production in the second half of 2020.
- The recently sanctioned Edam Central and Westhazel projects are expected to be brought online in the second half of 2021.

Production at Tucker averaged 22,600 bbls/day in the fourth quarter. Tucker is continuing to rise towards its 30,000 barrel-per-day design capacity, expected to be reached by the end of 2018. First oil from a new 15-well pad is expected in early March 2018, with production expected to ramp up in the first half of the year.

At Sunrise, bitumen production in the fourth quarter averaged 46,000 bbls/day (23,000 bbls/day Husky working interest), compared to 33,800 bbls/day (16,900 bbls/day Husky working interest) in the year-ago period. Production from 14 new well pairs is steadily increasing. Average gross production in February 2018 was approximately 47,200 bbls/day (23,600 bbls/day Husky working interest).

Resource Plays

A 16-well drilling program in the Ansell and Kakwa areas of the Wilrich formation was completed. Four wells brought on production in the fourth quarter delivered better than expected results, adding a combined 30 mmcf/day of new sales gas production in December 2017.

In the Wembley area, three liquids-rich gas wells were drilled in the Montney formation and production commenced on two oil wells at Karr.

Downstream

Throughputs at the Lloydminster Upgrader averaged 78,200 bbls/day, compared to 66,500 bbls/day in the fourth quarter of 2016.

At the Lima Refinery, throughputs averaged 164,500 bbls/day compared to 165,100 bbls/day in the fourth quarter of 2016. A crude oil flexibility project to increase heavy oil processing capacity from 10,000 bbls/day to 40,000 bbls/day by 2019 is in progress. At the partner-operated Toledo refinery, throughputs averaged 81,000 bbls/day (Husky working interest), compared to 78,800 bbls/day in the fourth quarter of 2016. Throughputs at the Superior Refinery averaged 37,000 bbls/day in December.

OFFSHORE

- Average production of 77,500 boe/day
- Operating netbacks of $62.63 per boe
    - Asia Pacific operating netback of $65.31 per boe
    - Atlantic operating netback of $59 per barrel

Asia Pacific

China
The Liwan Gas Project averaged record production of 361 mmcf/day in sales gas volumes, with associated liquids averaging 14,800 bbls/day (177 mmcf/day and 7,300 bbls/day Husky working interest). The Company realized gas pricing of $13.40 Cdn per thousand cubic feet (mcf).

The Board of Directors sanctioned Liuhua 29-1, the third deepwater field at Liwan. First gas is anticipated in 2021. Production will be tied directly into the existing Liwan subsea infrastructure and the onshore Gaolan Gas Plant, and delivered to buyers in the Pearl River Mouth Basin area.

Under the PSC, CNOOC Limited has the right to participate in any field development projects for up to a 51 percent working interest. Based on this level of participation, Husky expects to recover approximately $250 million US in exploration costs on a preferred basis within the first 18 months of production.

Indonesia
Gas sales at the liquids-rich BD Project were 40 mmcf/day (17 mmcf/day Husky working interest) with 6,200 bbls/day of associated liquids production (2,300 bbls/day Husky working interest). BD gas was sold to the East Java market at contracted rates for a realized price of $9.62 Cdn per mcf. Liquids pricing was $77.79 Cdn per barrel.

At the combined MDA-MBH fields in the Madura Strait, seven production wells are scheduled to be drilled in the first half of 2018, with first gas anticipated in 2019. The project shares infrastructure with the MDK field, which is set to be tied in during the same period. Gas will be processed on a floating production vessel and transported through the East Java subsea pipeline.

Atlantic

A development well was drilled at the main White Rose field, with first production achieved in late 2017. At North Amethyst, a development well was completed and is scheduled to be brought online in March 2018. Each of the two wells is expected to add 3,500 bbls/day (Husky working interest) at peak production.

West White Rose Project
Construction of the concrete gravity structure to support the topsides of the West White Rose Project is under way at a purpose-built graving dock in Argentia, Newfoundland and Labrador. The project is scheduled for completion in 2021, with first oil anticipated in 2022. West White Rose is expected to reach peak production of 75,000 bbls/day (52,500 bbls/day Husky working interest) in 2025 as development wells are drilled and brought online.

2018 PLANNED MAINTENANCE AND TURNAROUNDS

Integrated Corridor

- A five-week partial turnaround at the Lloydminster Upgrader in the second quarter; expect to maintain 80 percent throughput
- A five-week turnaround at the Superior Refinery in the second quarter
- A three-week turnaround at Tucker in the third quarter
- A five-week partial turnaround at the Lima Refinery in the fourth quarter; expect to maintain 40 percent throughput

Offshore

- A three-week turnaround at the *SeaRose* floating production, storage and offloading (FPSO) vessel starting in the second quarter
- A four-week turnaround at the *Terra Nova* FPSO in the third quarter

2017 ANNUAL RESULTS

Highlights:

Integrated Corridor

- Increased annual average production from Lloyd thermal bitumen projects, Tucker and Sunrise to 119,100 bbls/day, a 22 percent increase compared to 2016
- Acquired Superior Refinery in U.S. Midwest
- Created a single coast-to-coast truck transport network of approximately 160 travel centres/cardlock fuel facilities with Imperial Oil; expanded network and customer options has doubled Husky's cardlock diesel volumes
- Improved U.S. refining average utilization rate to 95 percent from 76 percent in 2016

Offshore

- Achieved record average quarterly Liwan sales gas production of 361 mmcf/day and associated record liquids production of 14,800 bbls/day (177 mmcf/day and 7,300 bbls/day Husky working interest); contributed to Asia Pacific operating netback of $63.39 per boe
- Delivered first sales gas production at BD Project; progressed additional fields at MDA-MBH and MDK

	2017 Investor Day Target	2017 Results	
Upstream production (mboe/day)	320-335	323[1]	Delivered
Funds from operations ($B)[2]	3.3	3.3[3]	Delivered
Free cash flow ($mm)[2]	750	1,086	Delivered
Capital expenditures ($B)[4,5]	2.5-2.6	2.2	Delivered
Upstream operating cost ($/bbl)	14-15	13.93	Delivered
Net debt to trailing FFO[2]	<2x	0.89x	Delivered
Five-year average proved reserves replacement ratio (%)	>130	167[6]	Delivered

[1] *Reflects legacy asset sales in Western Canada representing approximately 2,500 boe/day on an annualized basis, and the expiration of the Wenchang PSC in the fourth quarter of 2017.*
[2] *Non-GAAP measure; refer to advisory.*
[3] *Calculation of funds from operations changed from prior periods. Prior periods have been restated to conform to current presentation; refer to advisory.*
[4] *Excludes asset retirement obligations, capitalized interest and the acquisition of the Superior Refinery in Q4 2017.*
[5] *Excludes amounts related to the Husky-CNOOC Madura Ltd. joint venture and Husky Midstream Limited Partnership, which is accounted for under the equity method for financial statement purposes.*
[6] *Excludes economic factors; 165 percent including economic factors.*

2017 RESERVES REPLACEMENT

The 2017 proved reserves replacement ratio was 167 percent, excluding economic factors (165 percent including economic factors). The average five-year proved reserves replacement ratio was 144 percent, excluding economic factors (122 percent including economic factors). These take into account acquisitions and the disposition in Western Canada of 62 million boe of proved reserves in 2017 and 90 million boe of proved reserves in 2016.

The results exceed the five-year annual average proved reserves replacement ratio target outlined at Investor Day of more than 130 percent.

Total proved reserves before royalties at the end of 2017 were 1.3 billion boe. Probable reserves were 1.1 billion boe.

Proved reserves additions and revisions of 256 million boe, including economic factors, take into account additions related to the sanction of the West White Rose Project and three new Lloyd thermal bitumen projects, and improved performance in heavy oil production and Asia Pacific gas production.

CORPORATE DEVELOPMENTS

The Board of Directors has approved a quarterly dividend of $0.075 per common share for the three-month period ended December 31, 2017. The dividend will be payable on April 2, 2018, to shareholders of record at the close of business on March 20, 2018.

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, 2018. The dividends will be payable on April 2, 2018 to holders of record at the close of business on March 20, 2018.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	2.602	$0.16040
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 take place on Thursday, March 1 at 10 a.m. Mountain Time (12 p.m. Eastern Time) to discuss Husky's fourth quarter and annual results. CEO Rob Peabody, CFO Jon McKenzie and COO Rob Symonds 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 12 p.m. March 1):

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 2019
Duration: Available until April 2, 2018
Audio webcast: Available for 90 days at 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: the Company's general strategic plans and growth strategies; and potential benefits from changes to U.S. tax legislation;

- with respect to the Company's thermal developments in the Integrated Corridor: expected timing for first oil at Rush Lake 2; expected timing of construction and first oil at Dee Valley; expected timing of start-up at Spruce Lake North and Spruce Lake Central; expected timing for Edam Central and Westhazel to be brought online; expected timing to reach 30,000 bbls/day at the Tucker Thermal Project; and expected timing of first oil and production ramp-up from a new 15-well pad at the Tucker Thermal Project;

- with respect to the Company's Offshore business in Asia Pacific: expected timing of first gas at the Liuhua 29-1 field; expected value and timing of recovery of exploration costs under the PSC with CNOOC Limited; expected timing to drill seven production wells and expected timing of first gas at the MDA-MBH fields; and expected timing of tie-in at the MDK field;

- with respect to the Company's Offshore business in Atlantic: expected timing for the development well at North Amethyst to be brought online; expected peak production from the development wells at the main White Rose field and North Amethyst; expected timing of completion of and first oil at, and expected volume and timing of peak production at, West White Rose; and expected timing and duration of turnarounds at the *SeaRose* FPSO and the *Terra Nova* FPSO.

- with respect to the Company's Downstream operations in the Integrated Corridor, expected timing and duration of turnarounds at the Lloydminster Upgrader, Superior Refinery, Tucker Thermal Project and Lima Refinery.

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, 2017 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", "adjusted net earnings", "operating netback", "net debt" and "net debt to trailing funds from operations". 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. There is no comparable measure in accordance with IFRS for operating netback or net debt to trailing funds from operations.

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.

Funds from operations has been restated in the second quarter of 2017 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of adjustments for settlement of asset retirement obligations and deferred revenue. Prior periods have been restated to conform to current presentation.

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.

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								12 months ended	
($ millions)	Dec. 31 2017	Sept. 30 2017	June 30 2017	March 31 2017	Dec. 31 2016	Sept. 30 2016	June 30 2016	March 31 2016	Dec. 31 2017	Dec. 31 2016
Net earnings (loss)	672	136	(93)	71	186	1,390	(196)	(458)	786	922
Items not affecting cash:										
Accretion	28	27	29	28	30	29	33	34	112	126
Depletion, depreciation, amortization and impairment	647	673	862	700	405	638	697	722	2,882	2,462
Inventory write-down to net realizable value	—	-	-	-	9	-	-	-	—	9
Exploration and evaluation expenses	—	1	4	1	56	-	30	-	6	86
Deferred income taxes	(360)	52	(57)	6	45	99	(108)	(7)	(359)	29
Foreign exchange loss (gain)	1	(3)	15	(17)	(29)	12	12	1	(4)	(4)
Stock-based compensation	25	11	8	1	3	5	8	17	45	33
Loss (gain) on sale of assets	(13)	(2)	(33)	-	(52)	(1,680)	96	2	(46)	(1,634)
Unrealized mark to market loss (gain)	57	31	18	(50)	26	(28)	(83)	123	56	38
Share of equity investment loss	(1)	(12)	(23)	(25)	(38)	21	1	1	(61)	(15)
Other	8	9	5	(6)	29	(2)	(2)	(1)	16	24
Settlement of asset retirement obligations	(45)	(23)	(20)	(48)	(31)	(11)	(23)	(22)	(136)	(87)
Deferred revenue	(5)	(9)	-	-	23	146	40	-	(16)	209
Distribution from joint ventures	25	-	-	-	-	-	-	-	25	—
Change in non-cash working capital	337	3	98	(40)	(18)	124	(43)	(290)	398	(227)
Cash flow - operating activities	1,376	894	813	621	644	743	462	122	3,704	1,971
Change in non-cash working capital	(337)	(3)	(98)	40	18	(124)	43	290	(398)	227
Funds from operations	1,039	891	715	661	662	619	505	412	3,306	2,198
Capital expenditures	(745)	(511)	(580)	(384)	(391)	(309)	(595)	(410)	(2,220)	(1,705)
Free cash flow	294	380	135	277	271	310	(90)	2	1,086	493
Weighted average number of common shares outstanding	1,005.1	1,005.2	1,005.5	1,005.5	1,004.9	1,005.5	1,005.5	1,005.5	1,005.3	1,004.9
Funds from operations										
Per common share - Basic ($/share)	1.03	0.89	0.71	0.66	0.66	0.62	0.50	0.41	3.29	2.19

Adjusted net earnings (loss) 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. Adjusted net earnings (loss) is comprised of net earnings (loss) and excludes items such as after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on sale of assets which are not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing the Company's financial performance through providing comparability between periods. Adjusted net earnings (loss) was redefined in the second quarter of 2016. Previously, adjusted net earnings (loss) was defined as net earnings (loss) plus after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs.

The following table shows the reconciliation of net earnings (loss) to adjusted net earnings (loss) for the periods indicated:

		Three months ended								12 months ended	
		Dec 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Dec. 31
($ millions)		2017	2017	2017	2017	2016	2016	2016	2016	2017	2016
GAAP	Net earnings (loss)	672	136	(93)	71	186	1,390	(196)	(458)	786	922
	Impairment of property, plant and equipment, net of tax	3	-	123	-	(202)	-	12	-	126	(190)
	Exploration and evaluation asset write-downs, net of tax	-	1	3	-	41	-	22	-	4	63
	Inventory write-downs, net of tax	-	-	-	-	6	-	-	-	-	6
	Loss (gain) on sale of assets, net of tax	(10)	(1)	(23)	-	(37)	(1,490)	71	-	(34)	(1,456)
Non-GAAP	Adjusted net earnings (loss)	665	136	10	71	(6)	(100)	(91)	(458)	882	(655)
Weighted average number of common shares outstanding		1,005.1	1,005.2	1,005.2	1,005.5	1,004.9	1,005.5	1,005.5	1,005.5	1,005.3	1,004.9
Per common share - Basic ($/share)		0.66	0.14	0.14	0.07	(0.01)	(0.10)	(0.09)	(0.46)	0.88	(0.65)

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.

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.

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

	Dec. 30	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
($ millions)	2017	2017	2017	2017	2016	2016	2016	2016
Short-term debt	200	200	200	200	200	200	860	868
Long-term debt due within one year	-	-	390	400	403	656	260	259
Long-term debt	5,240	5,236	5,362	5,453	4,736	4,652	5,213	5,850
Total debt	5,440	5,436	5,952	6,053	5,339	5,508	6,333	6,977
Cash and cash equivalents	(2,513)	(2,486)	(2,500)	(2,245)	(1,319)	(1,380)	(20)	-
Net debt	2,927	2,950	3,452	3,808	4,020	4,128	6,313	6,977

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, 2017. 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.

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, 2017 and represent the Company's working interest share; (ii) projected and historical production volumes provided represent the

Company's working interest share before royalties; and (iii) historical production volumes provided are for the year ended December 31, 2017.

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 "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 has on reserves amounts.

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 Activities*, 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.