Husky Energy

Q3 NEWS RELEASE
Calgary, Alberta
October 26, 2017

Husky Energy Reports Third Quarter 2017 Results

Husky recorded funds from operations of $891 million in the third quarter, leading to free cash flow of $380 million.

"The steps we have taken to transform the Company's asset base continue to reduce our cost structure and increase funds from operations. Combined with strong Downstream performance, this is unlocking significant value and providing for ongoing investment in low cost production growth," said CEO Rob Peabody.

"Funds from operations have steadily increased over the past six quarters in a generally consistent price environment, demonstrating the ongoing asset transformation is delivering."

Net earnings and adjusted net earnings were $136 million, with net debt of $3.0 billion.

	2017			2016			
Results	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Funds from operations[1] ($mm)	891	715	661	662	619	505	412
Free cash flow[1] ($mm)	380	135	277	271	310	(90)	2
Adjusted net earnings[1] (loss) ($mm)	136	10	71	(6)	(100)	(91)	(458)
Net earnings (loss) ($mm)	136	(93)	71	186	1,390	(196)	(458)
Net debt[1] (billions)	3.0	3.5	3.8	4.0	4.1	6.3	7.0
Business Environment							
West Texas Intermediate crude oil ($US/bbl)	48.21	48.29	51.91	49.29	44.94	45.59	33.45
AECO ($Cdn/gigajoule)	1.93	2.63	2.79	2.67	2.09	1.18	2.00
Chicago 3:2:1 crack spread ($US/bbl)	19.30	14.36	11.22	10.59	14.29	16.67	9.23
Exchange rate ($Cdn/US)	0.799	0.744	0.756	0.750	0.766	0.776	0.728

[1]*Non-GAAP measure; refer to advisory.*

HIGHLIGHTS

- Funds from operations of $891 million, a year over year increase of 44 percent; reflects growing production from the Company's thermal bitumen developments and Liwan Gas Project, as well as increased U.S. refining margins and record Downstream throughputs
- Free cash flow of $380 million, a year over year increase of 23 percent
  - Year to date free cash flow of $792 million
- Upstream operating costs of $14.12 per barrel of oil equivalent (boe), down from $15.15 per boe in the third quarter of 2016; thermal bitumen operating costs of $10.54 per barrel
- Net debt of $3.0 billion, representing about one times net debt to trailing funds from operations
- First sales production from the liquids-rich BD Gas Project offshore Indonesia; 38.3 million cubic feet per day (15.3 mmcf/day Husky working interest) with a quarterly realized gas price of $9.39 per thousand cubic feet (mcf)
- Strong performance from the Liwan Gas Project; average production of 344 mmcf/day (169 mmcf/day Husky working interest), contributing to an overall Asia Pacific operating netback of $61.81 per boe
- Agreement to acquire the 50,000 barrel per day Superior Refinery in the U.S. Midwest; transaction expected to close in the fourth quarter of 2017
- Record Downstream throughputs of 374,000 barrels per day (bbls/day), compared to 320,000 bbls/day in Q3 2016
  - Downstream EBITDA of $393 million, an increase of 68 percent over $234 million in the third quarter of 2016

2017 Guidance Update

Annual production is expected to remain within the 2017 guidance range of 320,000-335,000 barrels of oil equivalent per day (boe/day), despite the sale of assets representing about 2,000 boe/day of annualized production. Reduced output in Western Canada as a result of legacy asset dispositions is being offset by growth in higher netback production, including strong performance from resource plays and Atlantic production.

Due in part to increased cost efficiencies, capital spending guidance for 2017 has been reduced to $2.2-2.3 billion, which does not include the pending acquisition of the Superior Refinery. Two Atlantic infill wells have been advanced to late 2017 and early 2018 and the Rush Lake 2 thermal project has been accelerated to Q1 2019. In addition, a decision to expand asphalt capacity in Lloydminster has been deferred and planned work at the Lima Refinery has been rescheduled to 2018.

Year-to-date Upstream operating costs are $14.17 per boe, and are expected to remain at the low end of the 2017 guidance range of $14 to $15 per boe.

THIRD QUARTER RESULTS

	Three Months Ended			Nine Months Ended	
	Sept. 30 2017	June 30 2017	Sept. 30 2016	Sept. 30 2017	Sept. 30 2016
Daily production, before royalties					
Total equivalent production (mboe/day)	318	320	301	324	319
Crude oil and NGLs (mbbls/day)	224	234	214	234	227
Natural gas (mmcf/day)	563	515	521	541	556
Upstream operating netback[1,2] ($/boe)	23.25	23.53	15.70	23.66	14.09
Refinery and Upgrader throughput (mbbls/day)	374	316	320	352	296
Funds from operations[1] ($mm)	891	715	619	2,267	1,536
Per common share – Basic ($/share)	0.89	0.71	0.62	2.25	1.53
Adjusted net earnings[1] (loss) ($mm)	136	10	(100)	217	(649)
Per common share – Basic ($/share)	0.14	0.01	(0.10)	0.22	(0.65)
Net earnings (loss) ($mm)	136	(93)	1,390	114	736
Per common share – Basic ($/share)	0.13	(0.10)	1.37	0.09	0.71

[1]*Non-GAAP measure; refer to advisory.*
[2]*Operating netback includes results from Upstream Exploration and Production and excludes Upstream Infrastructure and Marketing.*

Upstream production averaged 318,000 boe/day, compared to 301,000 boe/day in the third quarter of 2016, reflecting increased thermal bitumen production and Asia Pacific gas sales. It also takes into account planned turnarounds at both the *SeaRose* and *Terra Nova* floating production, storage and offloading (FPSO) vessels, seasonal maintenance at Lloyd thermal projects and the Tucker Thermal Project and the impact of dispositions since the end of the third quarter of last year, representing about 7,000 boe/day.

Average realized pricing for Upstream production was $40.05 per boe, compared to $33.11 per boe in Q3 2016. Upstream operating costs averaged $14.12 per boe compared to $15.15 per boe in Q3 2016. As a result, average Upstream operating netbacks were up 48 percent, averaging $23.25 per boe compared to $15.70 per boe in Q3 2016.

The Company's refineries and Lloydminster Upgrader achieved throughputs of 374,000 bbls/day, compared to 320,000 bbls/day in the third quarter of 2016.

The Chicago 3:2:1 crack spread averaged $19.30 US per barrel compared to $14.29 US per barrel in the year-ago period. Average realized U.S. refining margins were $13.38 US per barrel, which takes into account a pre-tax FIFO adjustment gain of $1.74 US per barrel. This compared to $7.34 US per barrel a year ago, which included a pre-tax FIFO adjustment loss of $2.61 US per barrel.

Funds from operations were $891 million, compared to $619 million in the third quarter of 2016. Capital expenditures were $511 million and free cash flow was $380 million.

INTEGRATED CORRIDOR

- Average Upstream production of 247,600 boe/day
- Upstream operating netback of $15.04 per boe, including a netback of $25.61 per barrel from thermal operations
- Average upgrading and refining throughputs of 374,000 bbls/day
- Canadian upgrading margin of $12.32 per barrel; U.S. refining margin of $13.38 US per barrel

Thermal Bitumen Production

Overall average thermal bitumen production from Lloyd heavy oil projects, the Tucker Thermal Project and the Sunrise Energy Project was 117,700 bbls/day, compared to 103,600 bbls/day in the third quarter of 2016. Overall thermal bitumen operating costs were $10.54 per barrel.

Construction of the 10,000 bbls/day Rush Lake 2 development continued to advance. Twelve well pairs are being drilled and construction of the Central Processing Facility is under way, with first oil now expected in Q1 of 2019.

A trio of Lloyd projects at Dee Valley, Spruce Lake North and Spruce Lake Central remain on track to start production in 2020, with a combined design capacity of 30,000 bbls/day.

At the Tucker Thermal Project, production reached 24,000 bbls/day and is continuing to rise towards its 30,000 bbls/day design capacity by the end of 2018. Drilling was completed on a new 15-well pad, with steaming expected to commence in the fourth quarter of 2017.

Average gross bitumen production at the Sunrise Energy Project is about 44,300 bbls/day month to date (22,150 bbls/day Husky working interest). In the third quarter, Sunrise production averaged 40,500 bbls/day (20,250 bbls/day Husky working interest) compared to 30,600 bbls/day (15,300 bbls/day Husky working interest) in the third quarter of 2016.

Steaming is ongoing on 14 previously drilled well pairs at Sunrise. First oil has been realized from 10 well pairs with the remaining four well pairs expected to be brought on production by the end of the fourth quarter. Overall Sunrise production was temporarily constrained in the third quarter due to the tie-in of the 14 additional well pairs and associated steam redirection.

Resource Plays

A 16-well program targeting the Wilrich formation in the Ansell and Kakwa areas is under way, with nine Wilrich wells drilled to date in 2017. Due to improved operating efficiencies, drilling times have been reduced by 30 percent since the start of 2017, contributing to a 22 percent reduction in drilling costs per well.

In the Montney formation, two liquids-rich gas wells have been drilled this year in the Wembley area. At Karr, two oil wells have been drilled, with first production now under way on the first well.

Downstream

Husky has agreed to acquire a 50,000 barrel per day refinery located in Superior, Wisconsin for $435 million US. The transaction, which is subject to regulatory approval and closing adjustments, is expected to close in the fourth quarter of 2017.

The acquisition will immediately increase heavy oil processing capacity, further improve crude and product storage and better position Husky to take advantage of growing asphalt demand across North America. Direct connectivity to the Company's pipeline in Hardisty, Alberta further mitigates exposure to the heavy-light oil differential.

An investment decision to expand asphalt capacity in Lloydminster has been deferred to post-2020 and will be considered again as heavy oil production increases.

With the addition of the Superior Refinery, Husky's total Downstream capacity will increase to approximately 395,000 bbls/day, including 190,000 bbls/day of heavy refining capacity, keeping value-added processing in line with growing production in Western Canada.

At the Lima Refinery, a crude oil flexibility project to increase heavy oil processing capacity from 10,000 bbls/day to 40,000 bbls/day is in progress.

OFFSHORE

- Average production of 70,150 boe/day
- Operating netbacks of $52.30 per boe
- Asia Pacific operating netback of $61.81 per boe
- Atlantic operating netback of $35.86 per barrel

Asia Pacific

China
The Liwan Gas Project averaged 344 mmcf/day in sales gas volumes, with associated liquids averaging 15,500 bbls/day (169 mmcf/day and 7,600 bbls/day Husky working interest.) The Company realized gas pricing of $13.05 Cdn per mcf.

A gas sales agreement was reached for future gas production from Liuhua 29-1, the third deepwater gas field at the Liwan Gas Project. Husky's Board of Directors is expected to review the project for sanctioning later this year. Construction is anticipated to begin in 2018 followed by first production in the 2021 timeframe. 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.

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

The PSC for the Wenchang oil field in the Pearl River Mouth Basin is due to expire in mid-November 2017, after which the Company will no longer have a working interest. Husky's 40 percent share of production averaged approximately 6,000 bbls/day in the third quarter.

Indonesia
The liquids-rich BD Gas Project, the first in a series of natural gas developments under way in the Madura Strait offshore Indonesia, recorded gas sales of 38.3 mmcf/day (15.3 mmcf/day Husky working interest). The first lifting of liquids took place in mid-October.

The project continues to ramp up towards full gas sales rates, with a sales production target of 100 mmcf/day of gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated liquids (2,400 bbls/day Husky working interest).

BD sales gas is being sold to the East Java market at contracted rates for a realized price of $9.39 Cdn per mcf.

Additional fields in the Madura Strait are being advanced. Seven production wells are scheduled to be drilled at the combined MDA-MBH fields in the first half of 2018, with first gas anticipated in the 2019 timeframe. A field at MDK is scheduled to be tied in during the same period, with all three fields sharing infrastructure.

Construction of a floating production vessel is in progress, with the processed gas to be transported through the East Java subsea pipeline.

Total sales volumes from the BD Gas Project and the MDA-MBH and MDK fields are expected to be approximately 250 mmcf/day of gas (100 mmcf/day Husky working interest) and 6,000 bbls/day of associated liquids (2,400 bbls/day Husky working interest) once production is fully ramped up.

Additional discoveries in the area continue to be evaluated for potential development.

Atlantic

A development well completed at South White Rose in the third quarter is expected to reach peak production of 4,500 bbls/day (Husky working interest) when ramped up. As a result of drilling and installation efficiencies realized from this project, the next two infill wells have been accelerated:

- At the main White Rose field, drilling is under way on a well originally planned for 2018; it is now expected to reach first oil in the fourth quarter of 2017.
- A well at North Amethyst will also be drilled ahead of schedule and is expected to begin production in early 2018.

Combined peak production from both wells is anticipated to be 8,800 bbls/day (Husky working interest) when ramped up.

The Company and its partner continue to assess a discovery at Northwest White Rose. A potential development could leverage the *SeaRose* FPSO, existing subsea infrastructure and the West White Rose wellhead platform. Husky has a 93.2 percent ownership interest in the discovery.

Planned turnarounds at the *SeaRose* and *Terra Nova* FPSOs were completed in September.

West White Rose
A contract was signed for fabrication of the topsides component of the West White Rose Project. Preparations for construction of the concrete gravity structure to support the topsides will begin in the fourth quarter at a purpose-built graving dock in Argentia, Newfoundland and Labrador.

The project is scheduled for completion in 2021. First production is expected in 2022, following installation and connection to the *SeaRose* FPSO via existing subsea infrastructure.

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. The expected net project cost to first oil is $2.2 billion.

CORPORATE DEVELOPMENTS

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 December 31, 2017.

The dividends will be payable on January 2, 2018 to holders of record at the close of business on November 27, 2017.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	2.472	$0.15577
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, Oct. 26 at 9 a.m. Mountain Time (11 a.m. Eastern Time) to discuss Husky's third quarter 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 11 a.m. Oct. 26)

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 1709
Duration: Available until November 26, 2017
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", "is estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "schedules" 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; expected annual production; capital spending guidance; and expected Upstream operating costs;

- with respect to the Company's thermal bitumen production in the Integrated Corridor: the anticipated timing of first production from, and design capacity of, the Company's Rush Lake 2 thermal bitumen development and its three additional Lloyd thermal bitumen projects at Dee Valley, Spruce Lake North and Spruce Lake Central; the expected timing of first steam and 2018 production expectations for the Tucker Thermal Project; and the expected timing of first production from the four remaining well pairs at the Sunrise Energy Project;

- with respect to the Company's resource plays in the Integrated Corridor, drilling plans;

- with respect to the Company's Downstream operations in the Integrated Corridor: the expected timing of closing of, and the anticipated benefits from, the acquisition of the Superior, Wisconsin refinery; and the expected timing of an investment decision to expand asphalt capacity at the Company's Lloydminster refinery;

- with respect to the Company's Offshore business in Asia Pacific: the anticipated timing of project sanctioning of, commencement of construction at and first production from Liuhua 29-1; the Company's expected recovery of exploration costs within the first 18 months of production from Liuhua 29-1; gross daily sales targets of natural gas and associated liquids at the BD Gas Project; the expected timing of drilling of seven production wells at the combined MDA-MBH fields, and the expected timing of first gas therefrom; the expected timing of tie-in of a field at MDK; and anticipated combined daily sales volumes from the BD Gas Project and the MDA-MBH and MDK fields once production is fully ramped up; and

- with respect to the Company's Offshore business in the Atlantic: the expected peak production from the development well at South White Rose when fully ramped up; the expected timing of first oil from a well at the main White Rose field; the expected timing of first production from a well at North Amethyst; the anticipated combined peak production from the two wells at White Rose and North Amethyst; a potential development at Northwest White Rose; the timing of preparations for construction and the timing of completion of the concrete gravity structure to support the topsides at the West White Rose Project; the expected timing and volume of gross peak production, and the expected net project cost to first oil, at the West White Rose Project.

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, including the timing of regulatory approvals, 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, 2016 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

NON-GAAP MEASURES

This news release contains references to the terms "funds from operations", "free cash flow", "adjusted net earnings (loss)", "net debt", "net debt to trailing funds from operations", "operating netback" and "EBITDA", which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and are therefore unlikely to be comparable to similar measures presented by other issuers. 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 EBITDA, there are no comparable measures to these non-GAAP measures in accordance with 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 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.

The following tables show the reconciliation of net losses to funds from operations and free cash flow for the periods indicated:

	Three months ended							Nine months ended	
	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31	Sept. 30	Sept. 30
($ millions)	2017	2017	2017	2016	2016	2016	2016	2017	2016
Net earnings (loss)	136	(93)	71	186	1,390	(196)	(458)	114	736
Items not affecting cash:									
Accretion	27	29	28	30	29	33	34	84	96
Depletion, depreciation, amortization and impairment	673	862	700	405	638	697	722	2,235	2,057
Inventory write-down to net realizable value	-	-	-	9	-	-	-	-	-
Exploration and evaluation expenses	1	4	1	56	-	30	-	6	30
Deferred income taxes	52	(57)	6	45	99	(108)	(7)	1	(16)
Foreign exchange loss (gain)	(3)	15	(17)	(29)	12	12	1	(5)	25
Stock-based compensation	11	8	1	3	5	8	17	20	30
Loss (gain) on sale of assets	(2)	(33)	-	(52)	(1,680)	96	2	(33)	(1,582)
Unrealized mark to market loss (gain)	31	18	(50)	26	(28)	(83)	123	(1)	12
Share of equity investment loss	(12)	(23)	(25)	(38)	21	1	1	(60)	23
Other	9	5	(6)	29	(2)	(2)	(1)	8	(5)
Settlement of asset retirement obligations	(23)	(20)	(48)	(31)	(11)	(23)	(22)	(91)	(56)
Deferred revenue	(9)	-	-	23	146	40	-	(11)	186
Change in non-cash working capital	3	98	(40)	(18)	124	(43)	(290)	61	(209)
Cash flow - operating activities	894	813	621	644	743	462	122	2,328	1,327
Change in non-cash working capital	(3)	(98)	40	18	(124)	43	290	(61)	209
Funds from operations	891	715	661	662	619	505	412	2,267	1,536
Capital expenditures	(511)	(580)	(384)	(391)	(309)	(595)	(410)	(1,475)	(1,314)
Free cash flow	380	135	277	271	310	(90)	2	792	222
Weighted average number of common shares outstanding	1,005.2	1,005.5	1,005.5	1,004.9	1,005.5	1,005.5	1,005.5	1,005.4	1,004.7
Funds from operations									
Per common share - Basic ($/share)	0.89	0.71	0.66	0.66	0.62	0.50	0.41	2.25	1.53

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) consists 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							Nine months ended	
		Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31	Sept. 30	Sept. 30
($ millions)		2017	2017	2017	2016	2016	2016	2016	2017	2016
GAAP	Net earnings (loss)	136	(93)	71	186	1,390	(196)	(458)	114	736
	Impairment of property, plant and equipment, net of tax	-	123	-	(202)	-	12	-	123	12
	Exploration and evaluation asset write-downs, net of tax	1	3	-	41	-	22	-	4	22
	Inventory write-downs, net of tax	-	-	-	6	-	-	-	-	-
	Loss (gain) on sale of assets, net of tax	(1)	(23)	-	(37)	(1,490)	71	-	(24)	(1,419)
Non-GAAP	Adjusted net earnings (loss)	136	10	71	(6)	(100)	(91)	(458)	217	(649)
Weighted average number of common shares outstanding		1,005.2	1,005.5	1,005.5	1,004.9	1,005.5	1,005.5	1,005.5	1,005.4	1,004.7
Per common share - Basic ($/share)		0.14	0.01	0.07	(0.01)	(0.10)	(0.09)	(0.46)	0.22	(0.65)

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:

	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
($ millions)	2017	2017	2017	2016	2016	2016	2016
Short-term debt	200	200	200	200	200	860	868
Long-term debt due within one year	-	390	400	403	656	260	259
Long-term debt	5,236	5,362	5,453	4,736	4,652	5,213	5,850
Total debt	5,436	5,952	6,053	5,339	5,508	6,333	6,977
Cash and cash equivalents	(2,486)	(2,500)	(2,245)	(1,319)	(1,380)	(20)	-
Net debt	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 and is equal to net debt divided by the 12-month trailing funds from operations as at September 30, 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.

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

DISCLOSURE OF OIL AND GAS INFORMATION

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.

Unless otherwise noted, projected and historical production volumes provided represent the Company’s working interest share before royalties.

All currency is expressed in Canadian dollars unless otherwise indicated.