Husky Energy Reports First Quarter 2018 Results

Husky Energy generated funds from operations of $895 million in the first quarter, leading to free cash flow of $218 million.

Net earnings were $248 million, up 250 percent compared to $71 million in the same period a year ago.

“Despite persistent discounts on Canadian heavy oil due to the ongoing lack of pipeline capacity, our integrated model showed its value,” said CEO Rob Peabody. “With almost 400,000 bbls/day in Canadian and U.S. upgrading and refining, long-term pipeline capacity and the flexibility to adjust quickly to market dynamics, we remain largely shielded from current differentials.

“Our fixed-price Asia Pacific business contributed strongly in the quarter, generating EBITDA of more than $250 million. Building on our long-standing and strong partnerships in the region, we are increasing our exposure to the fast-growing Asian energy market by taking a 75 percent working interest in the upcoming development of the Liuhua 29-1 field at the Liwan Gas Project.”

FIRST QUARTER HIGHLIGHTS

- Funds from operations of $895 million, up 35 percent over Q1 2017
- Capital spending of $637 million, primarily directed to increasing Lloyd thermal bitumen capacity and advancing the West White Rose Project
- Free cash flow of $218 million
- Quarterly cash dividend of $0.075 per common share declared
- Production of 300,400 barrels of oil equivalent per day (boe/day)
- Upstream average operating costs of $13.33 per boe, compared to $13.75 per boe in the first quarter of 2017
- Lowered annual production guidance range to 310,000-320,000 boe/day, reflecting a slower ramp up at the BD Project in Indonesia and a decision to temporarily reduce heavy oil production to take advantage of wide differentials in the quarter

Integrated Corridor

- Sunrise Energy Project reached 50,000 bbls/day (gross) in March
- Thermal bitumen production of 123,200 bbls/day
- Rush Lake 2 Lloyd thermal project ahead of schedule with first production now expected in Q4 2018
- Downstream throughputs of 398,100 bbls/day, with utilization rate of 92 percent
- Infrastructure and Marketing EBITDA of $190 million, reflecting additional margin capture from long-term 75,000 bbls/day committed capacity on existing Keystone pipeline

Offshore

- Increased working interest at Liuhua 29-1 to 75 percent from 49 percent, providing more exposure to growing gas markets in Asia

	Three Months Ended		
	Mar. 31 2018	Dec. 31 2017	Mar. 31 2017
Daily production, before royalties			
Total equivalent production (mboe/day)	300	320	334
Crude oil and NGLs (mbbls/day)	221	231	244
Natural gas (mmcf/day)	477	535	543
Upstream operating netback[1,2] ($/boe)	24.37	30.00	24.17
Refinery and Upgrader throughputs (mbbls/day)	398	387	367
Funds from operations[1] ($mm)	895	1,039	661
Per common share – Basic ($/share)	0.89	1.03	0.66
Adjusted net earnings[1] ($mm)	245	665	73
Per common share – Basic ($/share)	0.24	0.66	0.07
Net earnings ($mm)	248	672	71
Per common share – Basic ($/share)	0.24	0.66	0.06
Net debt[1] ($ billions)	3.2	2.9	3.8
Dividend per common share ($/share)	0.075	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.*

First Quarter Results

Upstream production averaged 300,400 boe/day, compared to 334,000 boe/day in the first quarter of 2017. This reflects factors including the disposition of assets in Western Canada that closed in 2017 and the end of the Wenchang Production Sharing Contract, as well as temporarily reducing heavy oil production in the Lloydminster area.

Average realized pricing for Upstream production was $40.87 per boe, compared to $41.58 per boe in the first quarter of 2017. Realized pricing for oil and liquids averaged $40.39 per boe, while natural gas averaged $7.03 per thousand cubic feet (mcf). Upstream operating costs averaged $13.33 per boe compared to $13.75 per boe in the year-ago period. Upstream operating netbacks averaged $24.37 per boe compared to $24.17 per boe in Q1 2017.

Total Downstream throughputs were 398,100 bbls/day, compared to 366,700 bbls/day a year ago, reflecting the first full quarter of operations at the Superior Refinery.

U.S. refining throughputs were 276,400 bbls/day, and Canadian upgrading and refining throughputs were 121,700 bbls/day, reflecting an overall utilization of 92 percent.

The Chicago 3:2:1 crack spread averaged $12.84 US per barrel compared to $11.22 US per barrel in the year-ago period.

Average realized U.S. refining margins were $8.51 US per barrel, which takes into account a pre-tax FIFO adjustment gain of $0.47 US per barrel. This compared to $7.08 US per barrel a year ago, which included a pre-tax FIFO adjustment gain of $0.38 US per barrel.

Husky continues to be largely shielded from wide heavy oil differentials, benefiting from heavy oil upgrading and refining, storage capacity and long-term transportation agreements.

Upgrading net earnings were $109 million, compared to $48 million in Q1 2017. Upgrading margins were $31.63 per barrel, compared to $19.83 per barrel in Q1 2017. Utilization at the Lloydminster Upgrader during the first quarter was 100 percent.

The Infrastructure and Marketing segment had net earnings of $138 million in the quarter, an increase from $70 million in Q1 2017 due to the wider WTI/WCS differential, which averaged $30.69 compared to $19.28 in the year-ago period. Infrastructure and Marketing's realized margins were $190 million, compared to $74 million in Q1 2017, reflecting value captured from the Company's long-term 75,000 bbls/day committed capacity on the existing Keystone pipeline.

Funds from operations were $895 million, compared to $661 million in the first quarter of 2017. Capital expenditures were $637 million and investment in joint ventures was $40 million, leading to free cash flow of $218 million. Net earnings were $248 million.

INTEGRATED CORRIDOR

- Upstream average production of 229,750 boe/day
- Upstream operating netback of $10.91 per boe, including a netback of $14.28 per barrel from thermal operations
- Downstream upgrading/refining margin of $17.02 per barrel
- Infrastructure and Marketing net earnings of $138 million and realized margins of $190 million

Thermal Production

Thermal bitumen production from Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project averaged 123,200 bbls/day (Husky working interest), compared to 120,600 bbls/day (Husky working interest) in the first quarter of 2017. Overall thermal operating costs were $11.54 per barrel.

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

- Construction of the Central Processing Facility at Rush Lake 2 is ahead of schedule, with first steam now expected in Q3 2018 and first oil in Q4 2018. Drilling on 12 well pairs was completed in the quarter.
- At Dee Valley, construction began in March 2018, with first oil anticipated in the first half of 2020. Site clearing is under way at Spruce Lake North and Spruce Lake Central, which are scheduled to start production in the second half of 2020.
- The Edam Central and Westhazel projects are expected to be brought online in the second half of 2021.

Production at Tucker averaged 22,500 bbls/day in the first quarter. First oil from a new 15-well pad was achieved, with production continuing to ramp up through the first half of 2018. Following planned maintenance in the third quarter, Tucker is expected to reach its 30,000 barrel-per-day design capacity by the end of 2018.

Sunrise reached 50,000 bbls/day (25,000 bbls/day Husky working interest) of bitumen production in March 2018. It averaged 46,800 bbls/day (23,400 bbls/day Husky working interest) in the first quarter, compared to 35,800 bbls/day (17,900 bbls/day Husky working interest) in the year-ago period. The steam-oil ratio for the original 55 well pairs averaged 3.4 in the quarter and continues to decline. Sunrise is expected to reach its 60,000 bbls/day design capacity by the end of 2018.

Resource Plays

An 18-well drilling program in the Ansell and Kakwa areas targeting the Wilrich formation is under way, with seven wells drilled during the quarter and four completed. In the oil and liquids-rich Montney formation, eight wells are expected to be drilled this year in the Wembley and Karr areas.

Downstream

Downstream throughput was 398,100 bbls/day, with EBITDA of $340 million, up 73 percent from the first quarter of 2017.

Throughputs at the Lloydminster Upgrader averaged 81,000 bbls/day, compared to 77,900 bbls/day in Q1 2017.

Total U.S. refining throughputs were 276,400 bbls/day. At the Lima Refinery, throughputs averaged 164,400 bbls/day compared to 172,000 bbls/day in the first quarter of 2017. A crude oil flexibility project to increase heavy oil processing capacity from 10,000 bbls/day to 40,000 bbls/day by 2019 continues to progress on schedule.

At the partner-operated Toledo refinery, throughputs averaged 75,000 bbls/day (Husky working interest), compared to 77,000 bbls/day (Husky working interest) in the first quarter of 2017. Throughputs at the Superior Refinery averaged 37,000 bbls/day.

OFFSHORE

- Average production of 70,650 boe/day
- Operating netback of $68.27 per boe
  - Asia Pacific operating netback of $70.31 per boe
  - Atlantic operating netback of $65.23 per barrel

Asia Pacific

China
Husky has increased its working interest in the development of the Liuhua 29-1 field to 75 percent from 49 percent, providing additional exposure to the growing energy market in Asia. Liuhua 29-1 is the third deepwater field at the Liwan Gas Project.

Based on this 75 percent level of participation, Husky expects to recover approximately $247 million US in exploration costs on a preferred basis within the first 18 months of production. The Company's share of capital spending on the project is expected to be approximately $670 million US, including $130 million US in capital already spent. Husky's working interest share of production when the project ramps up will be 45 million cubic feet per day (mmcf/day) gas and 1,800 bbls/day liquids.

Three wells are scheduled to be drilled at Liuhua 29-1 in the fourth quarter of 2018, adding to the four previously drilled wells. First gas is anticipated around the end of 2020. 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.

Gross production from the existing Liwan fields averaged 367 mmcf/day in sales gas volumes, with associated liquids averaging 16,700 bbls/day (180 mmcf/day and 8,200 bbls/day Husky working interest). The Company realized gas pricing of $13.95 Cdn per mcf.

Drilling began in March 2018 on an exploration well on Block 15/33 in the Pearl River Mouth Basin, with a second well scheduled in the second quarter. Drilling on two wells at the nearby Block 16/25 are planned for the second half of 2018.

Indonesia
Gas sales at the liquids-rich BD Project were 47 mmcf/day with 2,100 bbls/day of associated liquids production (19 mmcf/day and 1,000 bbls/day Husky working interest). BD gas was sold into the existing East Java market at contracted rates for a realized price of $9.85 Cdn per mcf. Liquids pricing was $87.53 Cdn per barrel.

At the combined MDA-MBH fields in the Madura Strait, seven production wells are scheduled to be drilled in the second half of 2018.

Atlantic

West White Rose Project
Initial construction work has commenced. 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.

Husky continues a subsea development well program at the White Rose field and satellite extensions. The 2018 program includes infill wells and workovers in the White Rose and North Amethyst fields.

2018 PLANNED MAINTENANCE AND TURNAROUNDS

Integrated Corridor

- A five-week partial turnaround is scheduled at the Lloydminster Upgrader in the second quarter; throughput expected to be maintained at 80 percent
- A five-week turnaround is planned at the Superior Refinery in the second quarter

- A three-week turnaround is scheduled at Tucker in the third quarter
- A five-week partial turnaround is planned at the Lima Refinery in the fourth quarter; throughput expected to average 40 percent

Offshore

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

2018 Production Guidance Update

In light of wide Canadian heavy oil differentials in the quarter, a decision has been made to temporarily reduce heavy oil production and substitute discounted third-party crude as feedstock for Husky's Downstream operations, optimizing the value captured. This includes advancing a turnaround at Tucker into the third quarter of 2018. The BD Project in Indonesia is also ramping up more slowly than expected.

As a result, annual production guidance for 2018 has been revised lower by 10,000 boe/day and is now expected to average in the range of 310,000-320,000 boe/day, exiting the year in the 330,000 boe/day to 340,000 boe/day range. Funds from operations for the year are still expected to be $4 billion. Capital expenditure guidance remains in the $2.9 billion to $3.1 billion range, resulting in annual free cash flow of about $1 billion.

CORPORATE DEVELOPMENTS

The Board of Directors has approved a quarterly dividend of $0.075 per common share for the three-month period ended March 31, 2018. The dividend will be payable on July 3, 2018 to shareholders of record at the close of business on June 4, 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 June 30, 2018. The dividends will be payable on July 3, 2018 to holders of record at the close of business on June 4, 2018.

Share Series	Dividend Type	Rate (%)	Dividend Paid ($/share)
Series 1	Regular	2.404	$0.15025
Series 2	Regular	2.901	$0.18082
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, April 26 at 8 a.m. Mountain Time (10 a.m. Eastern Time) to discuss Husky's 2018 first quarter results. CEO Rob Peabody, COO Rob Symonds and Acting 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 9 a.m. April 26):

Canada and U.S. Toll Free: 1-800-319-6413
Outside Canada and U.S.: 1-604-638-9010
Passcode: 2144
Duration: Available until May 26, 2018
Audio webcast: Available for 90 days at huskyenergy.com

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

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

Investor and Media Inquiries:

Rob Knowles, Manager, Investor Relations
587-747-2116

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

FORWARD-LOOKING STATEMENTS

Certain statements in this news release are forward-looking statements and information and financial outlook (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”, “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; annual production guidance for 2018; expected funds from operations for 2018; and capital expenditure guidance for 2018;

- with respect to the Company’s thermal developments in the Integrated Corridor: expected timing for first steam and first oil at Rush Lake 2; expected timing of first oil at Dee Valley; scheduled timing of start of production at Spruce Lake North and Spruce Lake Central; expected timing for Edam Central and Westhazel to be brought online; and expected timing to reach design capacity at the Tucker Thermal Project and the Sunrise Energy Project;

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

- with respect to the Company’s Offshore business in Asia Pacific: expected recovery of exploration costs and expected share of capital spending on the Liuhua 29-1 project; expected working interest share of production at Liuhua 29-1 when the project ramps up; drilling plans and anticipated timing of first gas at Liuhua 29-1; drilling plans at Block 15/33, Block 16/25 and the combined MDA-MBH fields;

- with respect to the Company’s Offshore business in Atlantic: expected timing of completion of and first oil at, and expected volume and timing of peak production at, the West White Rose Project; the 2018 subsea development well program at the White Rose and North Amethyst fields; and expected timing and duration of turnarounds at the *SeaRose* FPSO and the *Terra Nova* FPSO; and

- 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; and expected throughput at the Lloydminster Upgrader and Lima Refinery during their partial turnarounds.

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.

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

Although the Company believes that the expectations reflected by the forward-looking statements presented in this 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 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 netback”, “adjusted net earnings” and “net debt”, 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. There is no comparable measure in accordance with IFRS for operating netback.

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.

Funds from operations was 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 and investment in joint ventures.

Free cash flow has been restated in the first 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 addition 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		
($ millions)	Mar. 31 2018	Dec. 31 2017	Mar. 31 2017
Net earnings	248	672	71
Items not affecting cash:			
Accretion	24	28	28
Depletion, depreciation, amortization and impairment	618	647	700
Exploration and evaluation expenses	-	-	1
Deferred income taxes	77	(360)	6
Foreign exchange loss (gain)	1	1	(17)
Stock-based compensation	21	25	1
Loss (gain) on sale of assets	(4)	(13)	2
Unrealized mark to market loss (gain)	(86)	57	(50)
Share of equity investment gain	(9)	(1)	(25)
Other	2	8	(6)
Settlement of asset retirement obligations	(49)	(45)	(48)
Deferred revenue	(20)	(5)	(2)
Distribution from joint ventures	72	25	-
Change in non-cash working capital	(366)	337	(40)
Cash flow - operating activities	529	1,376	621
Change in non-cash working capital	366	(337)	40
Funds from operations	895	1,039	661
Capital expenditures	(637)	(745)	(384)
Investment in joint ventures	(40)	(81)	-
Free cash flow	218	213	277
Weighted average number of common shares outstanding - Basic	1,005.1	1,005.1	1,005.5
Per common share - Basic ($/share)	0.89	1.03	0.66

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.

Adjusted net earnings is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, net earnings as determined in accordance with IFRS, as an indicator of financial performance. Adjusted net earnings consists of net earnings 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 is a complementary measure used in assessing the Company's financial performance through providing comparability between periods. Adjusted net earnings was redefined in the second quarter of 2016. Previously, adjusted net earnings was defined as net earnings 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 to adjusted net earnings for the periods indicated:

	Three months ended		
	Mar. 31	Dec. 31	Mar. 31
($ millions)	2018	2017	2017
Net earnings	248	672	71
Impairment of property, plant and equipment, net of tax	-	3	-
Loss (gain) on sale of assets, net of tax	(3)	(10)	2
Adjusted net earnings	245	665	73
Weighted average number of common shares outstanding	1,005.1	1,005.1	1,005.5
Per common share - Basic ($/share)	0.24	0.66	0.07

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:

	Mar. 31	Dec. 31	Mar. 31
($ millions)	2018	2017	2017
Short-term debt	200	200	200
Long-term debt due within one year	-	-	400
Long-term debt	5,343	5,240	5,453
Total debt	5,543	5,440	6,053
Cash and cash equivalents	(2,301)	(2,513)	(2,245)
Net debt	3,242	2,927	3,808

DISCLOSURE OF OIL AND GAS INFORMATION

Unless otherwise noted, projected and historical production volumes provided represent the Company's working interest share before 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 Company uses the term "steam-oil ratio", which measures the average volume of steam required to produce a barrel of oil. This measure does not have a standardized meaning and should not be used to make comparisons to similar measures presented by other issuers.

All currency is expressed in Canadian dollars unless otherwise indicated.