

## Husky Energy Reports Second Quarter 2017 Results

Husky generated funds from operations of \$715 million in the second quarter, leading to free cash flow of \$135 million.

“Despite a challenging oil price environment and planned turnarounds at the Lloydminster Upgrader and asphalt refinery, we increased funds from operations and realized another quarter of positive free cash flow,” said CEO Rob Peabody.

“At the same time, investments to improve margin capture along our Integrated Corridor and high-netback natural gas and oil production in our Offshore business continue to mitigate our exposure to price differentials and increase our netbacks from each boe we produce. We are continuing to invest in a deep portfolio of projects that will further reduce our break-even point.”

Adjusted net earnings were \$10 million. Including impairment charges and gains on asset sales in Western Canada, net earnings were a loss of \$93 million.

Capital expenditures of \$580 million remain in line with the Company’s recently lowered guidance range of \$2.5-2.6 billion for 2017. Net debt at the end of the quarter was \$3.5 billion.

	Three Months Ended		
	June 30 2017	Mar 31 2017	June 30 2016
Funds from operations <sup>1</sup> (\$mm)	715	661	505
Adjusted net earnings <sup>1</sup> (loss) (\$mm)	10	71	(91)
Net earnings (loss) (\$mm)	(93)	71	(196)
Capital expenditures (\$mm)	580	384	595

<sup>1</sup>Non-GAAP measure; refer to advisory.

### Operational Highlights

- Commenced testing and commissioning of liquids-rich BD Gas Project offshore Indonesia
- Approved the West White Rose development; first oil expected in 2022
- New oil discovery at Northwest White Rose
- Completed planned turnarounds at the Lloydminster Upgrader and asphalt refinery

Average Upstream production was 320,000 barrels of oil equivalent per day (boe/day), compared to 316,000 boe/day in the second quarter of 2016. This takes into account approximately 34,500 boe/day of asset sales in Western Canada over the same period – including approximately 2,600 boe/day during the second quarter – which has been more than replaced by thermal bitumen production growth.

Production in June averaged 325,000 boe/day. Annual production is expected to remain on track with the Company’s guidance range of 320,000-335,000 boe/day.

Despite the completion of scheduled turnarounds at the Lloydminster Upgrader and asphalt refinery, total upgrading and refining throughputs averaged 316,000 barrels per day (bbls/day), compared to 255,000 bbls/day in the second quarter of 2016. This was due in part to strong performance at the Lima and Toledo refineries. Normal operations at the Upgrader and asphalt refinery have since resumed.

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Husky Energy is a Canadian-based integrated energy company. It is headquartered in Calgary, Alberta, Canada and its shares are publicly traded on the Toronto Stock Exchange under the symbols HSE, HSE.PR.A, HSE.PR.B, HSE.PR.C, HSE.PR.E and HSE.PR.G.

WTI prices averaged \$48.29 US per barrel compared to \$45.59 US per barrel in the second quarter of 2016.

Average realized pricing for total Upstream production was \$41.58 per boe, compared to \$34.59 per boe in Q2 2016.

The Chicago 3:2:1 crack spread averaged \$14.36 US per barrel compared to \$16.67 US per barrel in the second quarter of 2016. Average realized U.S. refining margins were \$7.42 US per barrel, which takes into account a FIFO loss of \$1.37 US per barrel. This compared to \$16.46 US per barrel a year ago, which included a \$8.94 US per barrel FIFO gain.

Funds from operations were \$715 million, or \$0.71 per common share, compared to \$505 million, or \$0.50 per common share, in the second quarter of 2016. This included a pre-tax FIFO loss of \$25 million, a \$20 million expense related to asset retirement obligations, and an \$18 million expense related to exploration wells in the Flemish Pass.

Capital expenditures were \$580 million and free cash flow was \$135 million.

Adjusted net earnings were \$10 million, compared to a loss of \$91 million in Q2 2016. Including asset impairments and gains on sales in Western Canada, net earnings were a loss of \$93 million, or \$0.10 per common share, compared to a loss of \$196 million, or \$0.20 per common share in the year-ago period.

	Three Months Ended			Six Months Ended	
	June 30 2017	Mar 31 2017	June 30 2016	June 30 2017	June 30 2016
Daily production, before royalties					
Total equivalent production (mboe/day)	320	334	316	327	329
Crude oil and NGLs (mbbls/day)	234	244	228	239	233
Natural gas (mmcf/day)	515	543	529	529	574
Upstream operating netback <sup>1,2</sup> (\$/boe)	23.53	24.17	17.30	23.85	13.34
Refinery and Upgrader throughput (mbbls/day)	316	367	255	341	284
Funds from operations <sup>1</sup>					
Per common share – Basic (\$/share)	0.71	0.66	0.50	1.37	0.91
Adjusted net earnings <sup>1</sup> (loss)					
Per common share – Basic (\$/share)	0.01	0.07	(0.09)	0.08	(0.55)
Net earnings (\$mm)					
Per common share – Basic (\$/share)	(0.10)	0.06	(0.20)	(0.04)	(0.67)
Net debt <sup>1</sup> (billions)	3.5	3.8	6.3	3.5	6.3

<sup>1</sup>Non-GAAP measure; refer to advisory.

<sup>2</sup>Operating netback includes results from Upstream Exploration and Production and excludes Upstream Infrastructure and Marketing.

## INTEGRATED CORRIDOR

- Average Upstream production of 246,800 boe/day
- Average upgrading and refining throughputs of 316,000 bbls/day
- Upstream operating netback of \$15.29 per boe
- Canadian upgrading margin of \$22.63 per barrel; U.S. refining margin of \$7.42 US per barrel

## Thermal Bitumen Production

Overall average thermal bitumen production from Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project was 117,400 bbls/day, reflecting seasonal maintenance activity.

Construction of the 10,000 bbls/day Rush Lake 2 development continued to advance, with first oil expected in the first half of 2019.

Three additional Lloyd thermal bitumen projects at Dee Valley, Spruce Lake North and Spruce Lake Central are on track to start production in 2020, with a combined design capacity of 30,000 bbls/day.

Drilling was completed on a new 15-well pad at the Tucker Thermal Project. Production from the new pad is anticipated to ramp up in the first half of 2018, with total Tucker production expected to grow towards its 30,000 bbls/day design capacity by the end of 2018.

The Sunrise Energy Project averaged gross bitumen production of 38,300 bbls/day (19,150 bbls/day Husky working interest) in the second quarter, compared to 35,800 bbls/day in the first quarter of 2017. Work is under way to tie in 14 previously drilled well pairs, with steaming now under way and first oil production forecast by the end of the year.

### **Downstream**

A scheduled seven-week turnaround was completed at the Lloydminster Upgrader in early July. The asphalt refinery in Lloydminster underwent a three-week maintenance program as planned.

Engineering work was advanced on a potential 30,000 bbls/day project to expand asphalt capacity in Lloydminster.

### **Resource Plays**

A 16-well program targeting the Wilrich formation in the Ansell and Kakwa areas is under way. Five wells were completed in the second quarter, with seven Wilrich wells drilled to date in 2017.

A four-well drilling program targeting the oil and liquids-rich Montney formation in the Wembley and Karr areas is continuing.

As part of the repositioning of the Western Canada business, the Company closed additional asset sales representing approximately 2,600 boe/day for total proceeds of \$123 million.

### **OFFSHORE**

- Average production of 72,700 boe/day
- Operating netbacks of \$51.54 per boe
  - \$61.90 per boe in Asia Pacific
  - \$42.08 per barrel in Atlantic

### **Asia Pacific**

#### *Indonesia*

The liquids-rich BD Gas Project in the Madura Strait began testing and commissioning in the second quarter and is expected to reach commercial production soon. Gas is being provided to the East Java market at contract rates of \$7 US per thousand cubic feet (mcf) for a realized price of approximately \$9.50 Cdn per mcf, with future escalation factors. Current gross sales are in the range of 30-40 million cubic feet per day (mmcf/day) with approximately 2,500 bbls/day of gas liquids (12-16 mmcf/day and 1,000 bbls/day Husky working interest).

The BD Gas Project is expected to ramp up throughout 2017 towards full gas sales rates, with a gross 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).

Four additional fields in the Madura Strait are being advanced. Shallow water platforms have been installed at the combined MDA-MBH and MDK fields, which are scheduled for first production in the 2019-2020 timeframe.

All three fields share infrastructure, including a floating production vessel, with the processed gas tied into the existing East Java subsea pipeline.

Total gross 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.

Pre-engineering activities are progressing at the MAC field, where an approved plan of development is in place. Additional discoveries in the region are being evaluated for potential development.

#### *China*

At the Liwan Gas Project, gross sales gas volumes averaged 272 mmcf/day, with associated liquids averaging 12,500 bbls/day (133 mmcf/day and 6,125 bbls/day Husky working interest.) The Company realized pricing of \$13.44 Cdn per mcf for its fixed-price sales gas production. Gross production in June averaged 331 mmcf/day, with associated liquids averaging 15,600 bbls/day. (162 mmcf/day and 7,700 bbls/day Husky working interest).

#### *Taiwan*

A 3D seismic survey program on Husky's Block DW-1, a 7,700 square-kilometre exploration block offshore Taiwan, is currently about 80 percent complete.

#### **Atlantic**

The Company is moving ahead with plans for a fixed wellhead platform to develop the West White Rose Project offshore Newfoundland and Labrador.

Construction of the concrete gravity structure and associated drilling facilities, utilities, support services, and accommodations for personnel, is scheduled to begin in the fourth quarter of 2017. First oil is expected in 2022, with the project anticipated to achieve a gross peak production rate of approximately 75,000 bbls/day in 2025 (52,500 bbls/day Husky working interest) as development wells are drilled and brought online.

Preparations are under way for a development well at South White Rose in the fourth quarter of 2017, with anticipated net peak production of 4,500 bbls/day Husky working interest.

Husky and its partner continue to assess a new discovery at Northwest White Rose, where a 100-metre (gross) light oil column was delineated in the second quarter.

In the Flemish Pass, two recently drilled exploration wells did not encounter commercial quantities of hydrocarbons.

#### **Q3 MAINTENANCE AND TURNAROUNDS**

- A three-week turnaround is planned at the *SeaRose* FPSO in the third quarter.
- A three-week turnaround at the partner-operated *Terra Nova* FPSO is scheduled in the third quarter.

#### **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 September 30, 2017.

The dividends will be payable on October 2, 2017 to holders of record at the close of business on August 28, 2017.

<u>Share Series</u>	<u>Dividend Type</u>	<u>Rate (%)</u>	<u>Dividend Paid (\$/share)</u>
Series 1	Regular	2.404	\$0.15025
Series 2	Regular	2.259	\$0.14235
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 Friday, July 21 at 9 a.m. Mountain Time (11 a.m. Eastern Time) to discuss Husky's second 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. July 21)

Canada and U.S. Toll Free: 1-800-319-6413  
Outside Canada and U.S.: 1-604-638-9010  
Passcode: 1531  
Duration: Available until August 21, 2017  
Audio webcast: Available for 90 days at [www.huskyenergy.com](http://www.huskyenergy.com) under Investor Relations

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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; the Company's general strategic plans and growth strategies; the Company's capital expenditure guidance range; and expected annual production;

- 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 anticipated timing of ramp-up of production from the new 15-well pad at the Tucker Thermal Project; the expected timing and volume of total production from the Tucker Thermal Project; and the expected timing of first oil production from the 14 previously drilled well pairs at the Sunrise Energy Project;
- with respect to the Company's Downstream operations in the Integrated Corridor, a potential asphalt expansion project in Lloydminster;
- with respect to the Company's Resource Plays in the Integrated Corridor, drilling plans;
- with respect to the Company's Offshore business in Asia Pacific: the expected timing of ramp-up to commercial production and full gas sales rates, and gross daily sales targets of gas and associated liquids, at the BD Gas Project; the expected timing of first production from the MDA-MBH and MDK fields; and anticipated combined daily gross sales volumes of gas and associated liquids 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 timing of construction of the concrete gravity structure and associated drilling facilities, utilities, support services and accommodations for personnel at the West White Rose Project; the expected timing of first oil and the expected timing and volume of gross peak production from the West White Rose Project; the expected timing of drilling of, and anticipated net peak production from, a development well at South White Rose; and the anticipated timing and duration of turnarounds at the *SeaRose* FPSO and the *Terra Nova* FPSO.

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

Although the Company believes that the expectations reflected by the forward-looking statements presented in this news release are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third-party consultants, suppliers and regulators, among others.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to the Company.

The Company's Annual Information Form for the year ended December 31, 2016 and other documents filed with securities regulatory authorities (accessible through the SEDAR website [www.sedar.com](http://www.sedar.com) and the EDGAR website [www.sec.gov](http://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” and “operating netback”, 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 under IFRS for operating netback.

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			Six months ended	
		June 30 2017	March 31 2017	June 30 2016	June 30 2017	June 30 2016
<i>(\$ millions)</i>						
GAAP	Net loss	<b>(93)</b>	(196)	(196)	<b>(22)</b>	(654)
	Impairment of property, plant and equipment, net of tax	<b>123</b>	12	12	<b>123</b>	12
	Exploration and evaluation asset write-downs, net of tax	<b>3</b>	22	22	<b>4</b>	22
	Loss (gain) on sale of assets, net of tax	<b>(23)</b>	71	71	<b>(23)</b>	71
Non-GAAP	Adjusted net earnings (loss)	<b>10</b>	(91)	(91)	<b>82</b>	(549)

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 table shows the reconciliation of net losses to funds from operations and free cash flow for the periods indicated:

	Three months ended			Six months ended	
	June 30	March 31	June 30	June 30	June 30
<i>(\$ millions)</i>	2017	2017	2016	2017	2016
Net loss	(93)	71	(196)	(22)	(654)
Items not affecting cash:					
Accretion	29	28	33	57	67
Depletion, depreciation, amortization and impairment	862	700	697	1,562	1,419
Exploration and evaluation expenses	4	1	30	5	30
Deferred income taxes	(57)	6	(108)	(51)	(115)
Foreign exchange loss (gain)	15	(17)	12	(2)	13
Stock-based compensation	8	1	8	9	25
Loss (gain) on sale of assets	(33)	—	96	(31)	98
Unrealized mark to market loss (gain)	18	(50)	(83)	(32)	40
Share of equity investment loss	(23)	(25)	1	(48)	2
Other	5	(6)	(2)	(3)	(3)
Settlement of asset retirement obligations	(20)	(48)	(23)	(68)	(45)
Deferred revenue	—	—	40	—	40
Change in non-cash working capital	98	(40)	(43)	58	(333)
Cash flow – operating activities	813	621	462	1,434	584
Change in non-cash working capital	(98)	40	43	(58)	333
Funds from operations	715	661	505	1,376	917
Capital expenditures	(580)	(384)	(595)	(964)	(1,005)
Free cash flow	135	277	(90)	412	(88)

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 June 30, 2017, March 31, 2017 and June 30, 2016:

	June 30	March 31	June 30
<i>(\$ millions)</i>	2017	2017	2016
Short-term debt	200	200	860
Long-term debt due within one year	390	400	260
Long-term debt	5,362	5,453	5,213
Total debt	5,952	6,053	6,333
Cash and cash equivalents	(2,500)	(2,245)	(20)
Net debt	3,452	3,808	6,313

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.