BAYTEX

ENERGY CORP.

BAYTEX REPORTS SOLID Q2 2017 RESULTS WITH 5% PRODUCTION GROWTH AND STRONG EAGLE FORD PERFORMANCE

CALGARY, ALBERTA (August 1, 2017) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and six months ended June 30, 2017 (all amounts are in Canadian dollars unless otherwise noted).

"Driven by excellent capital efficiencies across our portfolio, we have been able to substantially grow production largely within funds from operations during the first half of the year at US$50/bbl oil prices. This is due to some of the strongest well results we have seen to-date in the Eagle Ford and a safe and highly efficient start-up of our development program in Canada. Our team is pushing to reposition the business for success at these low commodity prices with production currently above the high end of guidance and capital expenditures tracking toward the low end of guidance," commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Generated production of 72,812 boe/d (79% oil and NGL) during Q2/2017, an increase of 5% from Q1/2017 and 12% from Q4/2016;
- Delivered funds from operations ("FFO") of $83.1 million ($0.35 per basic share) in Q2/2017 and $164.5 million ($0.70 per basic share) in H1/2017;
- Produced 38,528 boe/d in the Eagle Ford, an increase of 7% from Q1/2017 and 15% from Q4/2016, and 34,284 boe/d in Canada, an increase of 3% from Q1/2017 and 8% from Q4/2016;
- Established average 30-day initial gross production rates of approximately 2,150 boe/d per well from three recently completed pads (total of 11 wells) in the oil window of our Eagle Ford acreage;
- Realized an operating netback (sales price less royalties, operating and transportation expenses) in Q2/2017 of $18.30/boe ($18.70/boe including financial derivatives gain);
- Reduced annual guidance for operating expenses by 4% (at mid-point) to $10.75-$11.25/boe, reflecting strong performance in H1/2017 of $10.50/boe; and
- Tightened our 2017 production guidance range to 69,000 to 70,000 boe/d (previously 68,000 to 70,000 boe/d) and exploration and development capital expenditures to $310 to $330 million (previously $325 to $350 million).

	Three Months Ended			Six Months Ended	
	June 30, 2017	March 31, 2017	June 30, 2016	**June 30, 2017**	June 30, 2016
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 274,369**	$ 260,549	$ 195,733	**$ 534,918**	$ 349,331
Funds from operations (1)	**83,136**	81,369	81,261	**164,505**	126,906
Per share - basic	**0.35**	0.35	0.39	**0.70**	0.60
Per share - diluted	**0.35**	0.34	0.39	**0.70**	0.60
Net income (loss)	**9,268**	11,096	(86,937)	**20,364**	(86,330)
Per share - basic	**0.04**	0.05	(0.41)	**0.09**	(0.41)
Per share - diluted	**0.04**	0.05	(0.41)	**0.09**	(0.41)
Exploration and development	**78,007**	96,559	35,490	**174,566**	117,175
Acquisitions, net of divestitures	**5,226**	66,004	(37)	**71,230**	(46)
Total oil and natural gas capital expenditures	**$ 83,233**	$ 162,563	$ 35,453	**$ 245,796**	$ 117,129
Bank loan (2)	**$ 264,032**	$ 259,966	$ 347,083	**$ 264,032**	$ 347,083
Long-term notes (2)	**1,541,694**	1,574,116	1,544,181	**1,541,694**	1,544,181
Long-term debt	**1,805,726**	1,834,082	1,891,264	**1,805,726**	1,891,264
Working capital deficiency	**13,661**	16,827	51,247	**13,661**	51,274
Net debt (3)	**$ 1,819,387**	$ 1,850,909	$ 1,942,538	**$ 1,819,387**	$ 1,942,538

	Three Months Ended			Six Months Ended	
	June 30, 2017	March 31, 2017	June 30, 2016	**June 30, 2017**	June 30, 2016
OPERATING					
Daily production					
Heavy oil (bbl/d)	**25,577**	24,625	22,423	**25,104**	23,615
Light oil and condensate (bbl/d)	**22,370**	21,617	21,894	**21,996**	23,191
NGL (bbl/d)	**9,693**	8,306	9,834	**9,003**	9,971
Total oil and NGL (bbl/d)	**57,640**	54,548	54,151	**56,103**	56,777
Natural gas (mcf/d)	**91,028**	88,502	95,281	**89,771**	96,750
Oil equivalent (boe/d @ 6:1) (4)	**72,812**	69,298	70,031	**71,065**	72,902
Benchmark prices					
WTI oil (US$/bbl)	**48.29**	51.91	45.60	**50.10**	39.53
WCS heavy oil (US$/bbl)	**37.16**	37.34	32.29	**37.25**	25.76
Edmonton par oil ($/bbl)	**61.92**	63.98	54.78	**62.95**	47.80
LLS oil (US$/bbl)	**49.70**	52.50	46.20	**51.10**	39.73
Baytex average prices (before hedging)					
Heavy oil ($/bbl) (5)	**37.62**	35.96	30.09	**36.81**	20.87
Light oil and condensate ($/bbl)	**60.68**	63.26	52.42	**61.94**	44.79
NGL ($/bbl)	**22.70**	26.35	13.28	**24.38**	15.86
Total oil and NGL ($/bbl)	**44.06**	45.31	36.07	**44.67**	29.76
Natural gas ($/mcf)	**3.62**	3.52	1.94	**3.57**	2.17
Oil equivalent ($/boe)	**39.41**	40.16	30.52	**39.77**	26.06
CAD/USD noon rate at period end	**1.2983**	1.3322	1.3009	**1.2983**	1.3009
CAD/USD average rate for period	**1.3447**	1.3229	1.2885	**1.3338**	1.3317

COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**4.81**	6.97	9.04	**6.97**	9.04
Low	**2.87**	4.02	4.85	**2.87**	1.57
Close	**3.15**	4.54	7.50	**3.15**	7.50
Volume traded (thousands)	**216,383**	255,645	466,201	**472,026**	949,511
NYSE					
Share price (US$)					
High	**3.63**	5.19	7.14	**5.20**	7.14
Low	**2.15**	3.01	3.67	**2.15**	1.08
Close	**2.43**	3.65	5.79	**2.43**	5.79
Volume traded (thousands)	**109,758**	136,666	198,514	**248,931**	352,567
Common shares outstanding (thousands)	**234,204**	234,203	210,715	**234,204**	210,715

Notes:

(1) Funds from operations is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define funds from operations as cash flow from operating activities adjusted for changes in non-cash operating working capital and other operating items. Baytex's determination of funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund capital investments and potential future dividends. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and six months ended June 30, 2017.

(2) Principal amount of instruments.

(3) Net debt is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) and the principal amount of both the long-term notes and the bank loan.

(4) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(5) Heavy oil prices are calculated based on sales volumes, net of blending costs.

Operating Results

Our operating results for the second quarter reflect strong drilling results and an increased pace of activity in the Eagle Ford that began late in Q4/2016, the resumption of drilling activity in Canada and a full quarter contribution from the Peace River acquisition, which closed on January 20, 2017.

Production increased 5% to average 72,812 boe/d (79% oil and NGL) in Q2/2017, as compared to 69,298 boe/d (79% oil and NGL) in Q1/2017. Production in the first half of 2017 averaged 71,065 boe/d. During the second quarter, exploration and development capital expenditures totaled $78.0 million, bringing the aggregate spending in the first half of 2017 to $174.6 million. We participated in the drilling of 47 (15.3 net) wells with a 100% success rate during the second quarter.

Reflective of our strong operating results in the first half of the year, we are tightening our 2017 production guidance range to 69,000 to 70,000 boe/d (previously 68,000 to 70,000 boe/d). We are now forecasting full-year 2017 exploration and development capital expenditures of $310 to $330 million (previously $325 to $350 million). We are also reducing our guidance for operating expenses by 4% (at the mid-point) to $10.75-$11.25/boe as we continue to drive cost efficiencies in our business.

We will continue to employ a flexible approach to prudently manage our capital program as we target exploration and development capital expenditures at a level that approximates our funds from operations.

Eagle Ford

Our Eagle Ford asset in South Texas is one of the premier oil resource plays in North America. The assets generate the highest cash netbacks in our portfolio and contain a significant inventory of development prospects. In Q2/2017, we directed 76% of our exploration and development expenditures toward these assets.

Production increased 7% during the second quarter to average 38,528 boe/d (77% liquids), as compared to 36,081 boe/d in Q1/2017. During the second quarter, we averaged 4-5 drilling rigs and 1-2 completion crews on our lands. In Q2/2017, we participated in the drilling of 38 (9.4 net) wells and commenced production from 35 (8.1 net) wells. At quarter end, we had 51 (13.0 net) wells waiting on completion.

We continue to see strong well performance driven by enhanced completions in the oil window of our acreage with the cost to drill, complete, equip and tie-in a well of US$4.7-4.9 million. The wells that commenced production during the quarter have established 30-day initial gross production rates of approximately 1,500 boe/d per well. Our three recently completed Karnes City pads (total of 11 wells) within the oil window of our Longhorn acreage established 30-day initial gross production rates of approximately 2,150 boe/d per well. These pads were completed with approximately 30 effective frac stages per well and proppant per completed foot of approximately 1,900 pounds, which is more than double the frac intensity of wells previously drilled in the area.

Peace River

Our Peace River region, located in northwest Alberta, has been a core asset for us since we commenced operations in the area in 2004. Through our innovative multi-lateral horizontal drilling and production techniques, we are able to generate some of the strongest capital efficiencies in the oil and gas industry.

Production increased 8% during the second quarter to average 18,300 boe/d (93% heavy oil), as compared to 17,000 boe/d in Q1/2017. The production increase was driven by an active drilling program combined with a full quarter contribution from the Peace River acquisition, which closed on January 20, 2017.

We drilled 4 (4.0 net) wells during the second quarter and 7 (7.0 net) wells during the first six months of 2017. Six of the wells have been producing for more than 30 days and have established an average 30-day initial production rate of approximately 400 bbl/d per well and two of these wells ranked among the top oil wells drilled in Alberta during this period.

Lloydminster

Our Lloydminster region, which straddles the Alberta and Saskatchewan border, is characterized by multiple stacked pay formations at relatively shallow depths, which we have successfully developed through vertical and horizontal drilling, water flood and steam-assisted gravity drainage operations.

Production averaged approximately 8,600 boe/d (98% heavy oil) during the second quarter, as compared to 9,100 boe/d in Q1/2017. The reduced volumes reflect a lower pace of development activity during the second quarter due to spring break-up. We drilled 5 (1.9 net) wells during the second quarter and 22 (14.9 net) wells during the first six months of 2017.

Financial Review

We generated FFO of $83.1 million ($0.35 per share) in Q2/2017, compared to $81.4 million ($0.35 per share) in Q1/2017. The increase in FFO is largely due to higher production volumes, which more than mitigated the decline in crude oil prices. FFO in the first half of 2017 totaled $164.5 million ($0.70 per share), compared to $126.9 million ($0.60 per share) in the first half of 2016.

Financial Liquidity

We continue to maintain strong financial liquidity as our US$575 million revolving credit facilities are approximately two-thirds undrawn and our first meaningful long-term note maturity is not until 2021. With our strategy to target exploration and development capital expenditures at a level that approximates our funds from operations, we expect this liquidity position to be stable going forward.

Our revolving credit facilities, which currently mature in June 2019, are covenant-based and do not require annual or semi-annual reviews. We are well within our financial covenants on these facilities as our Senior Secured Debt to Bank EBITDA ratio as at June 30, 2017 was 0.7:1.0, compared to a maximum permitted ratio of 5.0:1.0, and our interest coverage ratio was 4.0:1.0, compared to a minimum required ratio of 1.25:1.0.

Our net debt totaled $1.8 billion at June 30, 2017, which is down $123 million from June 30, 2016. Our net debt is comprised of over 75% U.S. dollar borrowings and with the recent strengthening of the Canadian dollar relative to the U.S. dollar, we benefit as our net debt expressed in Canadian dollars is reduced. We also benefit from more than half of our operations being based in the U.S. along with approximately 70% of our 2017 exploration and development capital program being invested in the U.S., which mitigates our exposure to fluctuations in the Canada-U.S. dollar exchange rate.

Operating Netback

In Q2/2017, the price for West Texas Intermediate light oil ("WTI") averaged US$48.29/bbl, as compared to US$51.91/bbl in Q1/2017. Offsetting a portion of the decline in WTI was an improved pricing environment for Canadian heavy oil. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$11.13/bbl, as compared to US$14.57/bbl in Q1/2017.

We generated an operating netback in Q2/2017 of $18.30/boe ($18.70/boe including financial derivatives gain), as compared to $19.42/boe ($19.46/boe including financial derivatives gain) in Q1/2017 and $14.39/boe ($18.13/boe including financial derivatives gain) in Q2/2016. The Eagle Ford generated an operating netback of $24.14/boe during Q2/2017 while our Canadian operations generated an operating netback of $11.71/boe.

The following table summarizes our operating netbacks for the periods noted.

	Three Months Ended June 30					
	2017			2016		
($ per boe except for sales volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**34,284**	**38,528**	**72,812**	31,722	38,309	70,031
Realized sales price	**$ 33.86**	**$ 44.34**	**$ 39.41**	$ 25.80	$ 34.43	$ 30.52
Less:						
Royalty	**4.53**	**13.09**	**9.06**	2.74	9.89	6.65
Operating expense	**14.74**	**7.11**	**10.70**	10.84	6.88	8.67
Transportation expense	**2.88**	**—**	**1.35**	1.78	—	0.81
Operating netback	**$ 11.71**	**$ 24.14**	**$ 18.30**	$ 10.44	$ 17.66	$ 14.39
Realized financial derivatives gain	**—**	**—**	**0.40**	—	—	3.74
Operating netback after financial derivatives gain	**$ 11.71**	**$ 24.14**	**$ 18.70**	$ 10.44	$ 17.66	$ 18.13

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our FFO. We realized a financial derivatives gain of $2.6 million in Q2/2017.

For the second half of 2017, we have entered into hedges on approximately 48% of our net WTI exposure with 9% fixed at US$54.46/bbl and 39% hedged utilizing a 3-way option structure that provides us with downside price protection at

US$47.17/bbl and upside participation to US$58.60/bbl. We have also entered into hedges on approximately 49% of our net WCS differential exposure at a price differential to WTI of US$13.73/bbl and 68% of our net natural gas exposure through a combination of AECO swaps at C$3.00/mcf and NYMEX swaps at US$2.98/mmbtu.

We are also executing our hedge program for 2018. We have now entered into hedges on approximately 20% of our net WTI exposure with 15% fixed at US$51.28/bbl and 5% hedged utilizing a 3-way option structure that provides us with downside price protection at US$54.40/bbl and upside participation to US$60.00/bbl. We have also entered into hedges on approximately 20% of our net WCS differential exposure at a price differential to WTI of US$14.42/bbl and 19% of our net natural gas exposure through a combination of AECO swaps at C$2.82/mcf and NYMEX swaps at US$3.00/mmbtu.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q2/2017 financial statements.

2017 Guidance

The following table summarizes our 2017 annual guidance and compares it to our 2017 year-to-date actual results.

	2017 Guidance			
	Original (1)	**Revised (2)**	**H1/2017**	**Variance**
Exploration and development capital ($ millions)	300 - 350	310 - 330	174.6	N/A
Production (boe/d)	66,000 - 70,000	69,000 - 70,000	71,065	2 %
Expenses:				
Royalty rate (%)	~23.0	~23.0	22.8	(1)%
Operating ($/boe)	11.00 - 12.00	10.75 - 11.25	10.50	(2)%
Transportation ($/boe)	1.10 - 1.30	1.10 - 1.30	1.32	2 %
General and administrative ($/boe) (3)	~2.00	~2.00	2.07	4 %
Interest ($/boe)	~4.00	~4.00	3.97	(1)%

Notes:

(1) Original guidance as announced on December 12, 2016.

(2) On August 1, 2017, we tightened our exploration and development capital and production guidance ranges and reduced our operating expense guidance range by 4% (at the mid-point).

(3) General and administrative expenses in H1/2017 include non-recurring restructuring costs of $0.17/boe associated with staffing reductions. Excluding these restructuring costs, general and administrative expenses were $1.90/boe.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2017 and the related Management's Discussion and Analysis of the operating and financial results can be accessed immediately on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Today – August 1, 2017
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call today, August 1, 2017, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-866-226-4099 or international 1-647-427-2258. Alternatively, to listen to the conference call online, please enter http://edge.media-server.com/m/p/fb4ofhpe in your web browser.

An archived recording of the conference call will be available approximately two hours after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our 2017 production and capital expenditure guidance; our Eagle Ford assets, including our assessment that it is a premier oil resource play, the cost to drill, complete and equip a well and initial production rates from new wells drilled in Q2/2017; our Peace River assets, including that the area has some of the strongest capital efficiencies in the oil and gas industry and initial production rates from wells drilled in H1/2017; our belief that we have strong financial liquidity and that our liquidity position will remain stable going forward; our target for exploration and development capital expenditures to approximate funds from operations; the effect that a strengthening Canada-U.S. dollar exchange rate will have on our U.S. dollar denominated debt; that our U.S. operations mitigate our exposure to fluctuations in the Canada-U.S. dollar exchange rate; our ability to partially reduce the volatility in our funds from operations by utilizing financial derivative contracts for commodity prices, heavy oil differentials and interest and foreign exchange rates; the percentage of our anticipated 2017 and 2018 oil and natural gas production that is hedged; and our expected royalty rate and per boe operating, transportation, general and administrative and interest costs for 2017. In addition, information and statements relating to reserves and contingent resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices; a decline or an extended period of the currently low oil and natural gas prices; uncertainties in the capital markets that may restrict or increase our cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; availability and cost of gathering, processing and pipeline systems; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; we may lose access to our information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2016, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Non-GAAP Financial Measures

Funds from operations is not a measurement based on Generally Accepted Accounting Principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. Funds from operations represents cash generated from operating activities adjusted for changes in non-cash operating working capital and other operating items. Baytex's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund capital investments and potential future dividends to shareholders. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) and the principal amount of both the long-term notes and the bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Bank EBITDA is not a measurement based on GAAP in Canada. We define Bank EBITDA as our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items as set out in the credit agreement governing our revolving credit facilities. Bank EBITDA is used to measure compliance with certain financial covenants.

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

Advisory Regarding Oil and Gas Information

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Baytex Energy Corp.

Baytex Energy Corp. is an oil and gas corporation based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Approximately 79% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

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