BAYTEX
ENERGY CORP.

BAYTEX REPORTS Q1 2018 RESULTS WITH CONTINUED STRONG EAGLE FORD PERFORMANCE

CALGARY, ALBERTA (May 3, 2018) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months ended March 31, 2018 (all amounts are in Canadian dollars unless otherwise noted).

“We successfully executed our first quarter plan which puts us on track to deliver our 2018 guidance. In the Eagle Ford, we achieved record production rates from new wells and our strongest operating netback since 2014. In Canada, we continued to focus on cost and capital efficiency while managing WCS pricing volatility through active hedging, crude-by-rail and operational optimization. With our excellent asset quality and current commodity prices, we are poised to generate significant free cash flow going forward,” commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Generated production of 69,522 boe/d (79% oil and NGL) during Q1/2018 and delivered adjusted funds flow of $84 million ($0.36 per basic share).
- Realized an operating netback of $32.48/boe in the Eagle Ford, the strongest since 2014. Our light oil and condensate production in the Eagle Ford received a premium sales price of US$63.16/bbl (WTI plus US$0.29/bbl) given its proximity to Gulf Coast markets.
- Established average 30-day initial gross production rates of approximately 1,750 boe/d per well from 27 (5.5 net) wells in the Eagle Ford that commenced production in the first quarter. This represents an approximate 20% improvement over wells brought on production in 2017.
- Executed our Q1/2018 drilling program in Canada while optimizing operations in the face of volatile heavy oil prices. Our crude by rail volumes expanded by 25% to 6,500 bbl/d in Q1/2018 and to 8,000 bbl/d currently.
- Extended the maturity of our US$575 million revolving credit facilities by one year to June 2020. We maintain strong financial liquidity with the revolving credit facilities approximately 70% undrawn.

	Three Months Ended		
	March 31, 2018	December 31, 2017	March 31, 2017
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*			
Petroleum and natural gas sales	**$ 286,067**	$ 303,163	$ 260,549
Adjusted funds flow (1)	**84,255**	105,796	81,369
Per share – basic	**0.36**	0.45	0.35
Per share – diluted	**0.36**	0.44	0.34
Net income (loss)	**(62,722)**	76,038	11,096
Per share – basic	**(0.27)**	0.32	0.05
Per share – diluted	**(0.27)**	0.32	0.05
Exploration and development	**93,534**	90,156	96,559
Acquisitions, net of divestitures	**(2,026)**	(3,937)	66,004
Total oil and natural gas capital expenditures	**$ 91,508**	$ 86,219	$ 162,563
Bank loan (2)	**$ 212,571**	$ 213,376	$ 259,966
Long-term notes (2)	**1,525,595**	1,489,210	1,574,116
Long-term debt	**1,738,166**	1,702,586	1,834,082
Working capital (surplus) deficiency	**45,213**	31,698	16,827
Net debt (3)	**$ 1,783,379**	$ 1,734,284	$ 1,850,909

	Three Months Ended		
	March 31, 2018	December 31, 2017	March 31, 2017
OPERATING			
Daily production			
Heavy oil (bbl/d)	**24,868**	24,945	24,625
Light oil and condensate (bbl/d)	**20,967**	21,229	21,617
NGL (bbl/d)	**9,143**	9,872	8,306
Total oil and NGL (bbl/d)	**54,978**	56,046	54,548
Natural gas (mcf/d)	**87,261**	81,063	88,502
Oil equivalent (boe/d @ 6:1) (4)	**69,522**	69,556	69,298
Benchmark prices			
WTI oil (US$/bbl)	**62.87**	55.40	51.91
WCS heavy oil (US$/bbl)	**38.59**	43.14	37.34
Edmonton par oil ($/bbl)	**72.06**	69.02	63.98
LLS oil (US$/bbl)	**67.07**	60.50	52.50
Baytex average prices (before hedging)			
Heavy oil ($/bbl) (5)	**33.33**	42.03	35.96
Light oil and condensate ($/bbl)	**79.20**	72.64	63.26
NGL ($/bbl)	**26.17**	29.14	26.35
Total oil and NGL ($/bbl)	**49.63**	51.35	45.31
Natural gas ($/mcf)	**2.95**	2.89	3.52
Oil equivalent ($/boe)	**42.96**	44.75	40.16
CAD/USD noon rate at period end	**1.2901**	1.2518	1.3322
CAD/USD average rate for period	**1.2651**	1.2717	1.3229
COMMON SHARE INFORMATION			
TSX			
Share price (Cdn$)			
High	**4.35**	4.59	6.97
Low	**3.01**	2.95	4.02
Close	**3.53**	3.77	4.54
Volume traded (thousands)	**177,572**	195,013	255,645
NYSE			
Share price (US$)			
High	**3.54**	3.61	5.19
Low	**2.37**	2.30	3.01
Close	**2.74**	3.00	3.65
Volume traded (thousands)	**118,236**	113,647	136,666
Common shares outstanding (thousands)	**236,578**	235,451	234,203

Notes:

(1) Adjusted funds flow 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 adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three months ended March 31, 2018.

(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) We include the cost of blending diluent when calculating our realized heavy oil price.

Operating Results

Our operating results for the first quarter of 2018 were consistent with our expectations as we continued to deliver on our operational and financial targets. We successfully executed our first quarter drilling program and continued to drive cost and capital efficiency in our business. In addition, we optimized our heavy oil operations in the face of volatile heavy oil prices by curtailing production where appropriate, building crude inventory and deferring several completions until after spring break-up.

Production averaged 69,522 boe/d (79% oil and NGL) in Q1/2018, as compared to 69,556 boe/d (81% oil and NGL) in Q4/2017. Capital expenditures for exploration and development activities totaled $94 million in Q1/2018 and included the drilling of 55 (29.8 net) crude oil wells, one (1.0 net) natural gas well and six (6.0 net) stratigraphic and service wells with a 100% success rate. During the first quarter, our operating, transportation and general and administrative expenses totaled $13.65/boe, 3% below the mid-point of our annual guidance.

Our 2018 production guidance range is unchanged at 68,000 to 72,000 boe/d with budgeted exploration and development capital expenditures of $325 to $375 million.

Eagle Ford

Our Eagle Ford asset in South Texas is one of the premier oil resource plays in North America. The asset generates the highest cash netbacks in our portfolio and contains a significant inventory of development prospects. In Q1/2018, we allocated 45% of our exploration and development expenditures to this asset.

Production averaged 36,017 boe/d (78% oil and NGL) during the first quarter, as compared to 37,362 boe/d in Q4/2017. The reduced volumes reflect the timing of completion activity.

We continue to see strong well performance driven by enhanced completions in Karnes County. In addition, early results from Atascosa County are encouraging as we exploit the oil window on the western portion of our lands. In Q1/2018, we participated in the drilling of 25 (6.9 net) wells and commenced production from 27 (5.5 net) wells. The wells that have been on production for more than 30 days established 30-day initial production rates of approximately 1,750 boe/d, which represents an approximate 20% improvement over wells brought on production in 2017. These wells were completed with approximately 29 effective frac stages per well (compared to 23 in 2015) and proppant per completed foot of approximately 2,100 pounds (compared to 1,100 pounds in 2015).

Peace River

Our Peace River region, located in northwest Alberta, has been a core asset 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 averaged 16,500 boe/d (90% heavy oil) during the first quarter, as compared to 16,700 boe/d in Q4/2017. We drilled three (3.0 net) wells in Q1/2018. Our two multi-lateral horizontal wells at Reno averaged 19,255 metres of horizontal length and our first multi-lateral horizontal well on our northern Seal acreage (acquired in January 2017) was successfully drilled at 15,867 metres of horizontal length. These wells are expected to be brought on-stream during the second quarter.

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 ("SAGD") operations. We have also adopted, where applicable, the multi-lateral well design and geosteering capability that we have successfully utilized at Peace River.

Production averaged 10,000 boe/d (99% heavy oil) during the first quarter as compared to 9,600 boe/d in Q4/2017. We drilled 27 (19.9 net) crude oil wells and six (6.0) stratigraphic and service wells in Q1/2018. During the first quarter, four operated wells drilled in late 2017 established an average 30-day initial production rate of approximately 200 bbl/d per well. In addition, we completed the drilling of three (3.0 net) SAGD well pairs at our Kerrobert thermal project. Production at Kerrobert averaged 700 boe/d in Q1/2018 and we expect to exit 2018 producing approximately 2,000 boe/d.

Financial Review

We generated adjusted funds flow of $84 million ($0.36 per basic share) in Q1/2018, compared to $106 million ($0.45 per basic share) in Q4/2017 and $81 million ($0.35 per basic share) in Q1/2017. The reduction in adjusted funds flow relative to the fourth quarter is largely attributable to wider heavy oil differentials, which resulted in lower price realizations for our Canadian production, and realized financial derivatives losses.

Excluding realized financial derivatives gains and losses, adjusted funds flow in Q1/2018 was $94 million, compared to $104 million in Q4/2017. Despite the wide heavy oil differentials experienced during the first quarter, this represents the second highest quarterly adjusted funds flow (unhedged) since mid-2015 and demonstrates the benefit of our diversified asset portfolio.

Financial Liquidity

We maintain strong financial liquidity with our US$575 million revolving credit facilities approximately 70% undrawn and our first long-term note maturity not until 2021. With our strategy to target exploration and development capital expenditures at a level that approximates our adjusted funds flow, we expect this liquidity position to be stable going forward.

On April 25, 2018, we extended the maturity of our revolving credit facilities by one year to June 2020. These facilities are covenant-based and do not require annual or semi-annual reviews. We have also elected to end the covenant relief period that was set to expire on December 31, 2018 to benefit from reduced borrowing costs. We are well within the revised financial covenants on these facilities as our Senior Secured Debt to Bank EBITDA ratio as at March 31, 2018 was 0.5:1.0, compared to a maximum permitted ratio of 3.5:1.0, and our interest coverage ratio was 4.6:1.0, compared to a minimum required ratio of 2.0:1.0.

Our net debt totaled $1.78 billion at March 31, 2018, which is down from $1.85 billion at March 31, 2017.

Operating Netback

Our Q1/2018 operating netback of $20.71/boe (excluding financial derivatives) demonstrates the strength of our diversified asset portfolio. During the first quarter, we benefited from continued strong liquids pricing in the Eagle Ford, which was offset by the recent volatility in heavy oil price realizations in Canada. The Eagle Ford generated an operating netback of $32.48/boe during Q1/2018 while our Canadian operations generated an operating netback of $8.04/boe.

In Q1/2018, the price for West Texas Intermediate light oil (“WTI”) averaged US$62.87/bbl, as compared to US$51.91/bbl in Q1/2017. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select (“WCS”) and WTI, widened during Q1/2018 to US$24.28/bbl, as compared to US$14.57/bbl in Q1/2017. Subsequent to quarter-end, the WCS price differential has improved with the May Index averaging US$16.92/bbl.

In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the Louisiana Light Sweet (“LLS”) crude oil benchmark, which is a function of the Brent price. As a result, we benefit from a widening of the Brent-WTI spread. In addition, increased competition for physical field supplies has resulted in improved price realizations relative to LLS. During the first quarter, our light oil and condensate price in the Eagle Ford of US$63.16/bbl (or $79.90/bbl) represented a US$0.29/bbl premium to WTI and a US$3.91/bbl discount to LLS.

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

	Three Months Ended March 31					
	2018			2017		
($ per boe except for sales volume)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Sales volume (boe/d)	**33,505**	**36,017**	**69,522**	33,217	36,081	69,298
Realized sales price	**$ 29.69**	**$ 55.30**	**$ 42.96**	$ 32.81	$ 46.93	$ 40.16
Less:						
Royalties	**3.76**	**16.51**	**10.36**	4.23	13.72	9.17
Operating expense	**15.06**	**6.31**	**10.53**	14.52	6.38	10.28
Transportation expense	**2.83**	**—**	**1.36**	2.69	—	1.29
Operating netback	**$ 8.04**	**$ 32.48**	**$ 20.71**	$ 11.37	$ 26.83	$ 19.42
Realized financial derivatives (loss) gain	**—**	**—**	**(1.57)**	—	—	0.04
Operating netback after financial derivatives gain	**$ 8.04**	**$ 32.48**	**$ 19.14**	$ 11.37	$ 26.83	$ 19.46

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 adjusted funds flow. We realized a financial derivatives loss of $10 million in Q1/2018 due to the increased price of crude oil relative to the prices set in our contracts.

For the balance of 2018, we have entered into hedges on approximately 55% of our net crude oil exposure. This includes 45% of our net WTI exposure with 39% fixed at US$52.31/bbl and 6% 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. In addition, we have entered into a Brent-based hedge for 4,000 bbl/d at US$61.31/bbl. We have also entered into hedges on approximately 36% of our net WCS differential exposure at a price differential to WTI of US$14.43/bbl and 30% of our net natural gas exposure through a combination of AECO swaps at C$2.82/mcf and NYMEX swaps at US$3.01/mmbtu.

For 2019, we have entered into hedges on approximately 15% of our net crude oil exposure. This includes 13% of our net WTI exposure with 8% fixed at US$61.99/bbl and 5% hedged utilizing a 3-way option structure that provides us with downside price protection at US$60.00/bbl and upside participation to US$70.00/bbl. In addition, we have entered into a Brent-based 3-way option structure for 1,000 bbl/d that provides us with downside price protection at US$65.50/bbl and upside participation to US$75.50/bbl.

As part of our risk management program, we also transport crude oil to markets by rail when economics warrant. In Q1/2018, we delivered 6,500 bbl/d (approximately 25%) of our heavy oil volumes to market by rail, up from 5,000 bbl/d in 2017. We have secured additional rail capacity, which will see our crude oil volumes delivered to market by rail increase to approximately 8,000 bbl/d in Q2/2018.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q1/2018 financial statements.

2018 Guidance

The following table summarizes our 2018 annual guidance and compares it to our Q1/2018 actual results.

	Guidance (1)	Q1/2018	Variance
Exploration and development capital ($ millions)	325 - 375	93.5	-%
Production (boe/d)	68,000 - 72,000	69,522	-%
Expenses:			
Royalty rate (%)	~ 23.0	24.1	1%
Operating ($/boe)	10.50 - 11.25	10.53	-%
Transportation ($/boe)	1.35 - 1.45	1.36	-%
General and administrative ($ millions)	~ 44 (1.72/boe)	11.0 (1.76/boe)	-%
Interest ($ millions)	~ 100 (3.95/boe)	24.5 (3.92/boe)	(2)%

Note:

(1) As announced on December 7, 2017.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 31, 2018 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 Tomorrow
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call tomorrow, May 4, 2018, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter http://services.choruscall.ca/links/baytexq120180504.html in your web browser.

An archived recording of the conference call will be available shortly 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; that we expect to generate significant free cash flow going forward; our 2018 production and capital expenditure guidance; our Eagle Ford assets, including our assessment that: it is a premier oil resource play, generates our highest cash netbacks and has a significant development inventory; that we can generate some of the strongest capital efficiencies in the oil and gas industry at our Peace River assets; initial production rates from new wells; our expected exit production for 2018 at our Kerrobert thermal project; our strategy to target capital expenditures at a level that approximates our adjusted funds flow; our belief that we have strong financial liquidity and that our liquidity position will remain stable going forward; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts for commodity prices, foreign exchange rates and interest rates; the percentage of our anticipated 2018 and 2019 oil and natural gas production that is hedged; the volume of oil that we expect to deliver to market by railways in Q2/2018; and our expected royalty rate and operating, transportation, general and administration and interest expenses for 2018. 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 and price differentials; the availability and 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; availability and cost of gathering, processing and pipeline systems; public perception and its influence on the regulatory regime; 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; 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 oil 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; risks associated with our use of 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, 2017, 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 and Capital Management Measures

Adjusted funds flow 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 adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2017.

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 petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense 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 80% 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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