BAYTEX ENERGY CORP.

BAYTEX ANNOUNCES SECOND QUARTER 2019 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA (August 1, 2019) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and six months ended June 30, 2019 (all amounts are in Canadian dollars unless otherwise noted).

Our strong operating performance continues, with our Eagle Ford, Viking and heavy oil assets each delivering robust production and free cash flow. Given our year-to-date results, we are tightening our 2019 production guidance range to 96,000 to 97,000 boe/d (previously 95,000 to 97,000 boe/d) and lowering our budgeted exploration and development capital expenditure range to $550 to $600 million (previously $575 to $625 million). We generated a record level of free cash flow (approximately $200 million) in the first half of the year, which will allow us to redeem our US$150 million senior unsecured notes during the third quarter.

In addition, we are pleased to announce further exploration success in the East Duvernay shale with our (14-31) well brought on-stream June 27. The well has generated a 30-day initial production rate of 1,360 boe/d (76% liquids). This successful result in conjunction with a reduction in drilling and completion capital to approximately $7.0 million per well has solidified Pembina as a highly prospective region of the East Duvernay shale, in which we have a dominant land position of 268 net sections.

Q2/2019 Highlights

- Generated production of 98,402 boe/d (82% oil and NGL), exceeding the high end of our guidance.
- Delivered adjusted funds flow of $236 million ($0.42 per basic share), a 7% increase compared to $221 million ($0.40 per basic share) in Q1/2019.
- Reduced net debt by $147 million during the quarter ($236 million year-to-date) as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar.
- Realized an operating netback (inclusive of hedging) of $30.72/boe, our highest level since 2014.
- Eagle Ford production remained strong at 39,822 boe/d reflective of continued impressive well performance. We established average 30-day initial production rates of approximately 2,045 boe/d per well from 29 (5.0 net) wells that commenced production during the quarter.
- Production in Canada averaged 58,580 boe/d, down 2% (compared to Q1/2019) reflective of the seasonal slowdown in light oil activity during the second quarter. Heavy oil production increased 2% (compared to Q1/2019) due largely to the ramp-up of our Kerrobert thermal expansion project.
- Based on the free cash flow generated in the first half of 2019, we intend to redeem the US$150 million principal amount of 6.75% senior unsecured notes at par during the third quarter.
- Using the forward strip for 2019[1], we are now forecasting adjusted funds flow for 2019 of approximately $875 million. Further deleveraging remains a top priority with adjusted funds flow exceeding the midpoint of our capital guidance by $300 million.

    (1) Pricing assumptions: WTI - US$59/bbl; LLS - US$64/bbl; WCS differential - US$14/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$2.70/mcf; AECO Gas - $1.50/mcf and Exchange Rate (CAD/USD) - 1.32.

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	**June 30, 2019**	June 30, 2018
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 482,000**	$ 453,424	$ 347,605	**$ 935,424**	$ 633,672
Adjusted funds flow (1)	**236,130**	220,770	106,690	**456,900**	190,945
Per share - basic	**0.42**	0.40	0.45	**0.82**	0.81
Per share - diluted	**0.42**	0.40	0.45	**0.82**	0.81
Net income (loss)	**78,826**	11,336	(58,761)	**90,162**	(121,483)
Per share - basic	**0.14**	0.02	(0.25)	**0.16**	(0.51)
Per share - diluted	**0.14**	0.02	(0.25)	**0.16**	(0.51)
Capital Expenditures					
Exploration and development expenditures (1)	**$ 106,246**	$ 153,843	$ 78,830	**$ 260,089**	$ 172,364
Acquisitions, net of divestitures	**1,647**	—	(21)	**1,647**	(2,047)
Total oil and natural gas capital expenditures	**$ 107,893**	$ 153,843	$ 78,809	**$ 261,736**	$ 170,317
Net Debt					
Bank loan (2)	**$ 414,691**	$ 550,751	$ 213,538	**$ 414,691**	$ 213,538
Long-term notes (2)	**1,543,645**	1,569,153	1,548,490	**1,543,645**	1,548,490
Long-term debt	**1,958,336**	2,119,904	1,762,028	**1,958,336**	1,762,028
Working capital deficiency	**70,350**	55,337	22,807	**70,350**	22,807
Net debt (1)	**$ 2,028,686**	$ 2,175,241	$ 1,784,835	**$ 2,028,686**	$ 1,784,835
Shares Outstanding - basic (thousands)					
Weighted average	**556,599**	555,438	236,628	**556,022**	236,472
End of period	**556,798**	555,872	236,662	**556,798**	236,662

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	**June 30, 2019**	June 30, 2018
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**42,585**	45,048	21,100	**43,809**	21,034
Heavy oil (bbl/d)	**27,320**	26,891	25,544	**27,107**	25,208
NGL (bbl/d)	**10,986**	11,729	9,419	**11,356**	9,281
Total liquids (bbl/d)	**80,891**	83,668	56,063	**82,272**	55,523
Natural gas (mcf/d)	**105,065**	104,682	87,605	**104,874**	87,434
Oil equivalent (boe/d @ 6:1) (3)	**98,402**	101,115	70,664	**99,751**	70,095
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 461,110**	$ 436,636	$ 329,366	**$ 897,746**	$ 598,143
Royalties	**(86,617)**	(81,325)	(77,205)	**(167,942)**	(142,044)
Operating expense	**(100,474)**	(100,292)	(70,149)	**(200,766)**	(136,037)
Transportation expense	**(11,869)**	(13,330)	(7,836)	**(25,199)**	(16,355)
Operating netback (1)	**$ 262,150**	$ 241,689	$ 174,176	**$ 503,839**	$ 303,707
General and administrative	**(11,506)**	(14,136)	(10,563)	**(25,642)**	(21,571)
Cash financing and interest	**(28,092)**	(28,184)	(25,530)	**(56,276)**	(50,041)
Realized financial derivatives gain (loss)	**12,993**	18,814	(29,408)	**31,807**	(39,249)
Other (5)	**585**	2,587	(1,985)	**3,172**	(1,901)
Adjusted funds flow (1)	**$ 236,130**	$ 220,770	$ 106,690	**$ 456,900**	$ 190,945
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 51.49**	$ 47.98	$ 51.22	**$ 49.72**	$ 47.15
Royalties	**(9.67)**	(8.94)	(12.01)	**(9.30)**	(11.20)
Operating expense	**(11.22)**	(11.02)	(10.91)	**(11.12)**	(10.72)
Transportation expense	**(1.33)**	(1.46)	(1.22)	**(1.40)**	(1.29)
Operating netback (1)	**$ 29.27**	$ 26.56	$ 27.08	**$ 27.90**	$ 23.94
General and administrative	**(1.28)**	(1.55)	(1.64)	**(1.42)**	(1.70)
Cash financing and interest	**(3.14)**	(3.10)	(3.97)	**(3.12)**	(3.94)
Realized financial derivatives gain (loss)	**1.45**	2.07	(4.57)	**1.76**	(3.09)
Other (5)	**0.07**	0.28	(0.31)	**0.19**	(0.16)
Adjusted funds flow (1)	**$ 26.37**	$ 24.26	$ 16.59	**$ 25.31**	$ 15.05

Notes:

(1) The terms "adjusted funds flow", "exploration and development expenditures", "net debt" and "operating netback" do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. See the advisory on non-GAAP measures at the end of this press release.

(2) Principal amount of instruments. The carrying amount of debt issue costs associated with the bank loan and long-term notes are excluded on the basis that these amounts have been paid by Baytex and do not represent an additional source of liquidity or repayment obligations.

(3) 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.

(4) Realized heavy oil prices are calculated based on sales dollars, net of blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark.

(5) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and payments on onerous contracts. Refer to the Q2/2019 MD&A for further information on these amounts.

Operating Results

Our operating results for the second quarter of 2019 were buoyed by an improved commodity price environment along with strong operating performance in the Eagle Ford and Canada. We continued to realize the benefits of the Baytex and Raging River combination as we increased our operating netback, delivered meaningful free cash flow and strengthened our balance sheet.

Production during the second quarter averaged 98,402 boe/d (82% oil and NGL), as compared to 101,115 boe/d (84% oil and NGL) in Q1/2019. Production in the first half of 2019 averaged 99,751 boe/d, exceeding the high end of our full-year production guidance range.

Exploration and development expenditures totaled $106 million in Q2/2019, bringing aggregate spending in the first half of 2019 to $260 million. We participated in the drilling of 67 (52.0 net) wells with a 98% success rate during the second quarter.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 39,822 boe/d (76% liquids) during Q2/2019, as compared to 41,097 boe/d in Q1/2019. The lower volumes during the quarter reflect the timing of completion activity. We commenced production from 29 (5.0 net) wells during the second quarter, as compared to 36 (8.9 net) wells during the first quarter. The wells brought on-stream generated an average 30-day initial production rate of approximately 2,045 boe/d per well.

During Q2/2019, production from the Viking averaged 22,565 boe/d, as compared to 23,387 boe/d in Q1/2019. Our capital program in the second quarter included the seasonal slowdown, which resulted in the completion of 49 (40.0 net) wells, as compared to 79 (67.8 net) wells during the first quarter. We currently have four drilling rigs and one frac crew executing our program and remain on track to drill approximately 250 net wells this year. Inventory enhancement continues to be a priority. We have completed multiple deals and swaps year-to-date adding 160 net unbooked drilling opportunities.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 29,983 boe/d during the second quarter, as compared to 29,341 boe/d in Q1/2019. The higher volumes reflect the completion of three previously deferred wells at Peace River along with the ramp-up of our Kerrobert thermal expansion project.

With WCS differentials returning to historical levels, the returns associated with continued development of our heavy oil assets are competitive to those of our other plays. We expect to drill approximately 40 net heavy oil wells in the second half of 2019, as compared to nine net wells in the first half of the year.

East Duvernay Shale Light Oil

We continue to prudently advance the delineation of the East Duvernay Shale, an early stage, high operating netback light oil resource play. During the first half of 2019 we drilled four wells that continued 45 sections of land and further confirmed the prospectivity of our Pembina acreage.

Two of these wells were completed and initial flow back rates are very encouraging. The first well (14-31) was brought on-stream June 27 and generated a 30-day initial production rate of 1,360 boe/d (76% liquids). The second well (3-19) was brought on-stream July 26 and is currently producing 1,063 boe/d (89% liquids). These two wells were fracture stimulated using a "plug and perf" system and were the first Baytex wells to utilize fracture diversion technology. The other two wells were drilled to depth and encountered thick, well-developed shale sections with highly favorable geological characteristics including natural fracturing. Unfortunately both of these wells had to be abandoned due to wellbore stability issues. Having conducted an in-depth review of these two wells, we developed an improved drilling process and will re-drill these locations in the future.

Well costs have significantly improved with our two successful wells drilled and completed for an average cost of approximately $7.0 million per well. This represents an approximate 20% reduction from the average cost of our previous wells. As the play moves from delineation to development, the efficiency from multi-well pad operations is expected to drive further cost reductions.

The success of our drilling program in the Pembina area has significantly de-risked our approximately 38 kilometer long acreage fairway, where we hold 268 sections (100% working interest) of Duvernay land.

Financial Review

Our adjusted funds flow in Q2/2019 increased 7% as compared to Q1/2019, driven by strong operating performance in an improved commodity price environment. We generated adjusted funds flow of $236 million ($0.42 per basic share) in Q2/2019, compared to $221 million ($0.40 per basic share) in Q1/2019.

In Q2/2019, the price for West Texas Intermediate light oil ("WTI") averaged US$59.81/bbl, as compared to US$54.90/bbl in Q1/2019. The discount for Canadian light oil, as measured by the price differential between Canadian Mixed Sweet Blend ("MSW") and WTI, averaged US$4.61/bbl in Q2/2019 as compared to US$4.85/bbl in Q1/2019.The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$10.68/bbl in Q2/2019 as compared to US$12.29/bbl in Q1/2019. In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the LLS crude oil benchmark. In Q2/2019, the price for LLS averaged a US$7.34/bbl premium to WTI as compared to US$6.70/bbl in Q1/2019.

We generated an operating netback of $29.27/boe in Q2/2019, as compared to $26.56/boe in Q1/2019 and $27.08/boe in Q2/2018. Our Canadian operations generated an operating netback of $29.47/boe during Q2/2019 while our Eagle Ford asset generated an operating netback of $28.98/boe. Our operating netback in Canada has improved meaningfully with the inclusion of the high operating netback Viking light oil production.

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

	Three Months Ended June 30					
	2019			2018		
($ per boe except for production)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Production (boe/d)	**58,580**	**39,822**	**98,402**	34,042	36,622	70,664
Total sales, net of blending and other (1)	**$ 51.36**	**$ 51.69**	**$ 51.49**	$ 41.61	$ 60.16	$ 51.22
Royalties	**(5.80)**	**(15.37)**	**(9.67)**	(5.81)	(17.77)	(12.01)
Operating expense	**(13.86)**	**(7.34)**	**(11.22)**	(15.15)	(6.97)	(10.91)
Transportation expense	**(2.23)**	**—**	**(1.33)**	(2.53)	—	(1.22)
Operating netback (2)	**$ 29.47**	**$ 28.98**	**$ 29.27**	$ 18.12	$ 35.42	$ 27.08
Realized financial derivatives gain (loss)	**—**	**—**	**1.45**	—	—	(4.57)
Operating netback after financial derivatives	**$ 29.47**	**$ 28.98**	**$ 30.72**	$ 18.12	$ 35.42	$ 22.51

Notes:

(1) Realized heavy oil prices are calculated based on sales dollars, net of blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark.

(2) The term "operating netback" does not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. See the advisory on non-GAAP measures at the end of this press release.

Financial Liquidity

We are delivering on our commitment to generate meaningful free cash flow and improve our balance sheet. In aggregate, we reduced net debt by $147 million during the second quarter ($236 million year-to-date) as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar.

Our net debt, which includes our bank loan, long-term notes and working capital, totaled $2.0 billion at June 30, 2019. We maintain strong financial liquidity with our credit facilities approximately 60% undrawn and our first long-term note maturity not until 2021.

On May 2, 2019, we extended the maturity of our revolving credit facilities to April 2021. The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews. Our credit facilities total approximately $1.05 billion, comprised of US$575 million of revolving credit facilities and a $300 million non-revolving term loan.

Subsequent to quarter-end, we initiated plans to redeem US$150 million principal amount of 6.75% senior unsecured notes due February 17, 2021. Redemption of the notes is expected to occur during the third quarter and will be funded from the free cash flow generated during the first half of 2019.

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices. In an effort to manage these exposures, we utilize various financial derivative contracts, crude-by-rail and capital allocation optimization to reduce the volatility in our adjusted funds flow. We realized a financial derivatives gain of $13 million in Q2/2019.

For the balance of 2019, we have entered into hedges on approximately 48% of our net crude oil exposure. This includes 43% of our net WTI exposure with 18% fixed at US$62.82/bbl and 25% hedged utilizing a 3-way option structure that provides us with a US$10/bbl premium to WTI when WTI is at or below US$55.64/bbl and allows upside participation to US$73.65/bbl. In addition, we have entered into a Brent-based 3-way option structure for 3,000 bbl/d that provides a US$10/bbl premium to Brent when Brent is at or below US$59.50/bbl and allows upside participation to US$78.68/bbl. We have also entered into hedges on approximately 22% of our net natural gas exposure through a series of NYMEX swaps at US$3.10/mmbtu. For 2020, we have entered into hedges on approximately 15% of our net crude oil exposure, utilizing a 3-way option structure that provides us with a US$9/bbl premium to WTI when WTI is at or below US$51.00/bbl and allows upside participation to US$66.06/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For 2019, we expect to deliver 11,500 bbl/d (approximately 40%) of our heavy oil volumes to market by rail, up from 9,000 bbl/d in 2018. Approximately 70% of our crude by rail commitments are WTI based contracts with no WCS pricing exposure. In addition, for the balance of 2019, we have entered into WCS differential hedges on approximately 13% of our net heavy oil exposure at a WTI-WCS differential of US$17.49/bbl. We have also entered into a WTI-MSW basis differential swap for 4,000 bbl/d of our light oil production in Canada at US$8/bbl for June 2019 to December 2019.

A complete listing of our financial derivative contracts can be found in Note 18 to our Q2/2019 financial statements.

Outlook for 2019

Given our strong year-to-date operating performance, we are tightening our 2019 production guidance range to 96,000 to 97,000 boe/d (previously 95,000 to 97,000 boe/d) and lowering our budgeted exploration and development capital expenditure range to $550 to $600 million (previously $575 to $625 million).

Based on the forward strip for the balance of 2019(1), we are forecasting adjusted funds flow of approximately $875 million. Further deleveraging remains a top priority. For 2019, adjusted funds flow in excess of exploration and development expenditures, leasing expenditures and asset retirement obligations, will be used to reduce our indebtedness. Our year end 2019 net debt to trailing adjusted funds flow ratio is forecast to be 2.2x.

As we continue to drive debt levels down, we will be positioned to enhance shareholder returns through a combination of organic growth, disciplined capital allocation, the reinstatement of a dividend and/or share buybacks.

The following table summarizes our 2019 annual guidance and compares it to our 2019 year-to-date actual results.

	Guidance	YTD 2019
Exploration and development capital ($ millions) (2)	$550 - $600	$260.1
Production (boe/d) (2)	96,000 - 97,000	99,751
Expenses:		
Royalty rate (%) (2)	19%	18.7%
Operating ($/boe)	$10.75 - $11.25	$11.12
Transportation ($/boe)	$1.25 - $1.35	$1.40
General and administrative ($ millions)	$46 ($1.30/boe)	$25.6 ($1.42/boe)
Interest ($ millions)	$112 ($3.23/boe)	$56.3 ($3.12/boe)
Leasing expenditures ($ millions)	$5	3.0
Asset retirement obligations ($ millions)	$17	9.7

(1) 2019 full year pricing assumptions: WTI - US$59/bbl; LLS - US$64/bbl; WCS differential - US$14/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$2.70/mcf; AECO Gas - $1.50/mcf and Exchange Rate (CAD/USD) - 1.32.

(2) Our exploration and development capital and production guidance along with the expected royalty rate for 2019 has been updated as of August 1, 2019. Original guidance from December 2018: production – 93,000-97,000 boe/d; exploration and development capital - $550-$650 million; royalty rate - 20%.

The following table summarizes our annual adjusted funds flow sensitivities to changes in commodity prices and the CAD/USD exchange rate.

	Excluding Hedges ($ millions)	Including Hedges ($ millions)
Change of US$1.00/bbl WTI crude oil	$28.3	$18.2
Change of US$1.00/bbl WCS heavy oil differential	$11.4	$9.5
Change of US$1.00/bbl MSW light oil differential	$9.2	$7.7
Change of US$0.25/mcf NYMEX natural gas	$9.4	$7.5
Change of $0.01 in the CAD/USD exchange rate	$11.0	$11.0

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2019 and the related Management's Discussion and Analysis of the operating and financial results can be accessed 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
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call today, August 1, 2019, 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/baytexq220190801.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; our 2019 production and capital expenditure guidance; that we will redeem our US $150 million senior unsecured notes with free cash flow generated in H1/2019; our per well drill and complete cost for the East Duvernay; that the Pembina region of the East Duvernay shale is highly prospective; our forecast for 2019 adjusted funds flow; that deleveraging remains a top priority; in the Viking: that we expect to drill 250 wells in 2019 and inventory enhancement remains a priority; that WCS differentials mean that our heavy oil assets are competitive to our other assets and that we intend to drill 40 net wells on our heavy oil wells in H2/2019; in the East Duvernay shale: that we continue to prudently advance the delineation of the asset, that we have developed an improved drilling process, the locations we will drill in the future, our expectation that multi-well pad operations will drive cost reductions in the future and that we have de-risked our 38 kilometer acreage faiway; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts for commodity prices, foreign exchange rates and interest rates; the percentage of our net crude oil and natural gas exposure that is hedged for 2019 and 2020 and the amount and percentage of heavy oil production we expect to delivery by crude by rail and the percentage of crude by rail deliveries that do not have WCS exposure; our planned uses for adjusted funds flow in 2019; our forecast year end 2019 net debt to adjusted funds flow ratio; that we will be positioned to enhance shareholder returns through organic growth, capital allocation, the reinstatement of a dividend and/or share buybacks; guidance for 2019 capital spending and production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligation expenditures; the sensitivity of our 2019 adjusted funds flow to changes in WTI, WCS, MSW and NYMEX prices and the C$/US$ exchange rate. 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 described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves 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; availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; 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; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; 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; alternatives to and changing demand for petroleum products; 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, 2018, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings.

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 that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate 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. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. 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 and six months ended June 30, 2019.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less sustaining capital. Sustaining capital is an estimate of the amount of exploration and development expenditures required to offset production declines on an annual basis and maintain flat production volumes.

Exploration and development expenditures is not a measurement based on GAAP in Canada. We define exploration and development expenditures as additions to exploration and evaluation assets combined with additions to oil and gas properties. We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of trade and other accounts receivable, trade and other accounts payable, 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 and provides a key measure to assess our liquidity. We use the principal amounts of the bank loan and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the bank loan and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of liquidity or repayment obligation.

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 and is a key measure used to evaluate our operating performance.

Advisory Regarding Oil and Gas Information

This press release discloses the acquisition of 160 net unbooked drilling opportunities in our Viking asset. The additional drilling opportunities are unbooked locations and are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production.

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. BOEs 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 83% 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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