BAYTEX ANNOUNCES FOURTH QUARTER AND FULL YEAR 2018 FINANCIAL AND OPERATING RESULTS AND 2018 YEAR END RESERVES

CALGARY, ALBERTA (March 6, 2019) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2018 (all amounts are in Canadian dollars unless otherwise noted).

“In 2018, we repositioned our company through the Raging River combination which increased our high netback light oil assets while also deleveraging our balance sheet. Our operations are performing exceptionally well as we execute our first quarter program with activity focused on the Viking and Eagle Ford. We are also benefitting from a meaningful improvement in crude oil prices in Canada and on the Texas Gulf coast, which is expected to have a very positive impact to our adjusted funds flow. We are well positioned to execute our business plan and further strengthen our balance sheet in 2019,” commented Ed LaFehr, President and Chief Executive Officer.

2019 Outlook

Global benchmark prices have recently improved with WTI currently trading at US$57/bbl, as compared to a low of US$42/bbl in December 2018. In addition, Canadian light and heavy oil differentials have narrowed substantially. This combination is expected to have a positive impact to our adjusted funds flow.

As a result of current activity levels, excellent well performance in the Eagle Ford and outstanding operating efficiency across all of our assets, Q1/2019 volumes are ahead of expectations, trending above 97,000 boe/d.

Capital expenditures are on pace for $155 million in Q1/2019, consistent with the mid-point of our capital guidance range of $600 million. Approximately 80% of our capital program is directed to our high operating netback light oil assets in the Eagle Ford and Viking.

Further deleveraging remains a top priority. Based on the forward strip, our adjusted funds flow forecast has increased from $605 million in December 2018, to approximately $800 million, which will support up to $200 million of debt repayment while maintaining production at the mid-point of our guidance of 95,000 boe/d.

2018 Highlights

- Generated production of 98,890 boe/d (83% oil and NGL) during Q4/2018, an increase of 42% over Q4/2017, and 80,458 boe/d for full-year 2018, exceeding the high end of guidance, with capital expenditures of $496 million, in line with annual guidance.
- Delivered adjusted funds flow of $111 million ($0.20 per basic share) in Q4/2018 and $473 million ($1.35 per basic share) for the full-year 2018.
- Eagle Ford production increased 3% to 38,437 boe/d (78% liquids) in Q4/2018, compared to Q3/2018. Wells that commenced production during the quarter generated 30-day initial gross production rates of approximately 1,800 boe/d per well.
- Continued to advance the evaluation of the East Duvernay Shale where we now have five producing wells on our Pembina acreage. In Q4/2018, production more than doubled from Q3/2018, to average 1,432 boe/d.
- Decreased cash costs (operating, transportation and general and administrative expenses) for 2018 by 4% on a boe basis as compared to the mid-point of original guidance.
- Increased proved developed producing ("PDP") reserves by 35%, from 100 mmboe to 135 mmboe. Proved reserves (“1P”) increased by 23%, from 256 mmboe to 315 mmboe. Proved plus probable (“2P”) reserves increased by 22%, from 432 mmboe to 527 mmboe.
- Reserves associated with the Raging River assets increased by 4% on a 2P basis to 111 mmboe, as compared to year-end 2017. The Raging River combination enhanced the quality of Baytex’s reserves base, adding high value light oil reserves in the Viking and Duvernay.
- PDP finding and development ("F&D") costs, including changes in future development capital (“FDC”), were $15.82/boe, resulting in a 1.5x recycle ratio based on our 2018 operating netback of $23.76/boe.
- Our net asset value at year-end 2018, discounted at 10%, is estimated to be $7.27 per share.

	Three Months Ended			Years Ended	
	December 31, 2018	September 30, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 358,437**	$ 436,761	$ 303,163	**$ 1,428,870**	$ 1,099,867
Adjusted funds flow [1]	**110,828**	171,210	105,796	**472,983**	347,641
Per share - basic	**0.20**	0.46	0.45	**1.35**	1.48
Per share - diluted	**0.20**	0.45	0.44	**1.35**	1.47
Net income (loss)	**(231,238)**	27,412	76,038	**(325,309)**	87,174
Per share - basic	**(0.42)**	0.07	0.32	**(0.93)**	0.37
Per share - diluted	**(0.42)**	0.07	0.32	**(0.93)**	0.37
Capital Expenditures					
Exploration and development expenditures [1]	**$ 184,162**	$ 139,195	$ 90,156	**$ 495,721**	$ 326,266
Acquisitions, net of divestitures	**183**	46	(3,937)	**(1,818)**	59,857
Total oil and natural gas capital expenditures	**$ 184,345**	$ 139,241	$ 86,219	**$ 493,903**	$ 386,123
Net Debt					
Bank loan [2]	**$ 522,294**	$ 490,565	$ 213,376	**$ 522,294**	$ 213,376
Long-term notes [2]	**1,596,323**	1,527,733	1,489,210	**1,596,323**	1,489,210
Long-term debt	**2,118,617**	2,018,298	1,702,586	**2,118,617**	1,702,586
Working capital deficiency	**146,550**	93,792	31,698	**146,550**	31,698
Net debt [1]	**$ 2,265,167**	$ 2,112,090	$ 1,734,284	**$ 2,265,167**	$ 1,734,284
Shares Outstanding - basic (thousands)					
Weighted average	**554,036**	375,435	235,451	**351,542**	234,787
End of period	**554,060**	553,950	235,451	**554,060**	235,451

	Three Months Ended			Years Ended	
	December 31, 2018	September 30, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**44,987**	29,731	21,229	**29,264**	21,314
Heavy oil (bbl/d)	**26,339**	27,036	24,945	**25,954**	25,326
NGL (bbl/d)	**10,327**	10,076	9,872	**9,745**	9,206
Total liquids (bbl/d)	**81,653**	66,843	56,046	**64,963**	55,846
Natural gas (mcf/d)	**103,424**	93,414	81,063	**92,971**	86,375
Oil equivalent (boe/d @ 6:1) (3)	**98,890**	82,412	69,556	**80,458**	70,242
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 344,682**	$ 417,213	$ 286,370	**$ 1,360,038**	$ 1,040,522
Royalties	**(79,765)**	(91,945)	(69,525)	**(313,754)**	(241,892)
Operating expense	**(97,857)**	(77,698)	(69,837)	**(311,592)**	(269,283)
Transportation expense	**(10,994)**	(9,520)	(7,658)	**(36,869)**	(33,985)
Operating netback	**$ 156,066**	$ 238,050	$ 139,350	**$ 697,823**	$ 495,362
General and administrative	**(14,096)**	(10,158)	(9,717)	**(45,825)**	(47,389)
Cash financing and interest	**(27,933)**	(26,343)	(24,849)	**(104,318)**	(100,482)
Realized financial derivatives (loss) gain	**(3,063)**	(30,854)	1,898	**(73,165)**	7,616
Other (5)	**(146)**	515	(886)	**(1,532)**	(7,466)
Adjusted funds flow (1)	**$ 110,828**	$ 171,210	$ 105,796	**$ 472,983**	$ 347,641
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 37.89**	$ 55.03	$ 44.75	**$ 46.31**	$ 40.58
Royalties	**(8.77)**	(12.13)	(10.86)	**(10.68)**	(9.43)
Operating expense	**(10.76)**	(10.25)	(10.91)	**(10.61)**	(10.50)
Transportation expense	**(1.21)**	(1.26)	(1.20)	**(1.26)**	(1.33)
Operating netback (1)	**$ 17.15**	$ 31.39	$ 21.78	**$ 23.76**	$ 19.32
General and administrative	**(1.55)**	(1.34)	(1.52)	**(1.56)**	(1.85)
Cash financing and interest	**(3.07)**	(3.47)	(3.88)	**(3.55)**	(3.92)
Realized financial derivatives (loss) gain	**(0.34)**	(4.07)	0.30	**(2.49)**	0.30
Other (5)	**(0.02)**	0.07	(0.14)	**(0.05)**	(0.29)
Adjusted funds flow (1)	**$ 12.17**	$ 22.58	$ 16.54	**$ 16.11**	$ 13.56

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. We refer you to 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 2018 MD&A for further information on these amounts.

Strategic Combination with Raging River

On August 22, 2018, we completed a strategic combination with Raging River Exploration Inc. ("Raging River") by way of a plan of arrangement in which Baytex acquired all of the issued and outstanding common shares of Raging River. The strategic combination increased our light oil exposure and operational control of our properties while strengthening our balance sheet. The addition of these operated assets to our portfolio increased our inventory of drilling prospects and our ability to effectively allocate capital. Production from Raging River's properties is approximately 90% light oil from the Viking and Duvernay areas. Our 2018 results include 132 days of operations from the Raging River assets from August 22 to December 31.

In Q4/2018, production from the Raging River assets averaged 26,035 boe/d (93% oil and NGL). Reserves associated with the Raging River assets increased by 4% on a 2P basis to 111 mmboe, as compared to year-end 2017.

Operating Results

2018 was a defining year as we repositioned Baytex as a North American crude oil producer with strong free cash flow and an improved balance sheet. We have successfully integrated the two companies, undertaken a detailed strategic review of our operations, confirmed the organic growth opportunities in our diversified portfolio of assets and delivered on our near-term operational targets.

Production averaged 98,890 boe/d (83% oil and NGL) in Q4/2018, as compared to 82,412 boe/d (81% oil and NGL) in Q3/2018 and 69,556 boe/d in Q4/2017. Production of 80,458 boe/d (81% oil and NGL) for 2018 exceeded the high end of our production guidance range of 79,000 to 80,000 boe/d. Production from the legacy Baytex assets (excluding Raging River) averaged 72,855 boe/d in Q4/2018 and 71,293 boe/d for 2018.

Exploration and development expenditures totaled $184 million in Q4/2018 and $496 million for full-year 2018, in line with our guidance range of $450-$500 million. We participated in the completion of 353 (198.6 net) wells with a 99% success rate during the year.

Eagle Ford and Viking Light Oil

Our Eagle Ford assets in South Texas is one of the premier oil resource plays in North America. These assets generate a strong operating netback and free cash flow and contain a significant inventory of development prospects.

In 2018, we allocated 39% of our exploration and development expenditures to these assets. Production averaged 38,437 boe/d (78% liquids) during Q4/2018, as compared to 37,198 boe/d in Q3/2018. Production for 2018 averaged 37,076 boe/d, as compared to 36,678 boe/d in 2017. In 2018, the Eagle Ford generated an operating netback of $479 million and free cash flow of $285 million.

We continue to see strong well performance driven by enhanced completions in the oil window of our acreage. In 2018, we participated in the drilling of 91 (20.8 net) wells and commenced production from 120 (26.2 net) wells. The wells that have been on production for more than 30 days during 2018 established 30-day initial production rates of approximately 1,750 boe/d per well (65% light oil and condensate), which represents an approximate 20% improvement over 2017. During Q4/2018, we commenced production from 31 (5.9 net) wells, which averaged 30-day initial production rates of approximately 1,800 boe/d per well. Six of these were new appraisal wells in our northern Austin Chalk fracture trend and demonstrated 30-day initial production rates of approximately 1,600 boe/d per well.

Our Viking asset is a shallow, light oil resource play in western Canada. During Q4/2018, production from the Viking averaged 23,784 boe/d (excluding heavy oil), up from 22,158 boe/d for the period August 22 to September 30. We maintained a steady pace of development in Q4/2018 with five drilling rigs and 1.5 frac crews executing our program, resulting in 83 (65.5 net) wells. The extended reach horizontal results continue to exceed expectations with multiple, previously untested sections proving economic.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 26,339 bbl/d during the fourth quarter, as compared to 27,036 bbl/d in Q3/2018. The reduced volumes reflect the optimization of our heavy oil program during Q4/2018 due to volatile heavy oil prices, which was mitigated somewhat by the addition of heavy oil assets acquired as part of the Raging River combination.

Our Peace River assets are located in northwest Alberta. 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. In 2018, we drilled 12 (12.0 net) oil wells with average 30-day initial production rates of approximately 500 boe/d per well. This program included 8 (8.0 net) wells in our northern Seal area which delivered approximately 25% higher 30-day initial production rates than our field wide average. We deferred three completions during Q4/2018 due to low heavy oil prices.

Our Lloydminster assets are characterized by multiple stacked pay formations at relatively shallow depths. The area has been successfully developed through vertical and horizontal drilling, water flood, steam-assisted gravity drainage operations and, more recently, the implementation of polymer flooding to further enhance reserves recovery. We drilled 86 (61.9 net) oil wells in 2018. In addition, we successfully completed the expansion of our Kerrobert thermal project with productive capability increasing to approximately 2,000 bbl/d during Q4/2018.

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 where we have amassed over 450 sections of land. In 2018, our focus shifted to the Pembina area where we control over 270 sections of 100% working interest land. With five wells on production, we have delineated approximately 35 sections representing 175 potential drilling opportunities. These wells generated average 30-day initial production rates of approximately 575 boe/d per well (88% liquids). During Q4/2018, production from the East Duvernay Shale averaged 1,432 boe/d, up from 650 boe/d for the period August 22 to September 30.

Financial Review

Our financial results for Q4/2018 were negatively impacted by the sharp decline in global benchmark crude oil prices and the significant widening of Canadian light and heavy oil differentials. In Q4/2018, the price for West Texas Intermediate light oil ("WTI") averaged US$58.81/bbl, as compared to US$69.50/bbl in Q3/2018. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$39.42/bbl in Q4/2018 as compared to US$22.25/bbl in Q3/2018. The discount for Canadian light oil, as measured by the price differential between Canadian Mixed Sweet Blend ("MSW") and WTI, averaged US$26.51/bbl in Q4/2018 as compared to US$6.82/bbl in Q3/2018.

As a result of the challenging pricing environment, we generated adjusted funds flow of $111 million ($0.20 per basic share) in Q4/2018, compared to $171 million ($0.46 per basic share) in Q3/2018. Full-year adjusted funds flow was $473 million ($1.35 per basic share), compared to $348 million ($1.48 basic per share) in 2017.

We generated an operating netback $17.15/boe in Q4/2018, as compared to $31.39/boe in Q3/2018 and $21.78/boe in Q4/2017. The Eagle Ford generated an operating netback of $35.42/boe during Q4/2018 while our Canadian operations generated an operating netback of $5.54/boe.

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, which is a function of the Brent price. In Q4/2018, the price for LLS averaged US$66.64/bbl as compared to US$75.25/bbl in Q3/2018. During Q4/2018, our light oil and condensate realized price in the Eagle Ford of US$62.87/bbl (or $83.28/bbl) represented a US$3.77/bbl discount to LLS.

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

	Three Months Ended December 31					
	2018			2017		
($ per boe except for production)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Production (boe/d)	**60,453**	**38,437**	**98,890**	32,194	37,362	69,556
Total sales, net of blending and other (1)	**$ 24.04**	**$ 59.66**	**$ 37.89**	$ 36.89	$ 51.53	$ 44.75
Royalties	**(3.10)**	**(17.68)**	**(8.77)**	(5.72)	(15.30)	(10.86)
Operating expense	**(13.42)**	**(6.56)**	**(10.76)**	(16.57)	(6.04)	(10.91)
Transportation expense	**(1.98)**	**—**	**(1.21)**	(2.59)	—	(1.20)
Operating netback (2)	**$ 5.54**	**$ 35.42**	**$ 17.15**	$ 12.01	$ 30.19	$ 21.78
Realized financial derivatives (loss) gain	**—**	**—**	**(0.34)**	—	—	0.30
Operating netback after financial derivatives	**$ 5.54**	**$ 35.42**	**$ 16.81**	$ 12.01	$ 30.19	$ 22.08

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. We refer you to the advisory on non-GAAP measures at the end of this press release.

Financial Liquidity

We maintain strong financial liquidity with our credit facilities approximately 50% undrawn and our first long-term note maturity not until 2021. Our net debt totaled $2.265 billion at December 31, 2018, which includes four series of long-term notes that total $1.6 billion. Our credit facilities total approximately $1.085 billion, comprised of US$575 million of revolving credit facilities and a $300 million non-revolving term loan. The credit facilities, which mature in June 2020, are not borrowing base facilities and do not require annual or semi-annual reviews. We expect to request an extension to the credit facilities in 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 loss of $73 million in 2018, as compared to a gain of $8 million in 2017.

For 2019, we have entered into hedges on approximately 30% of our net crude oil exposure. This includes 25% of our net WTI exposure with 2% fixed at US$62.85/bbl and 23% hedged utilizing a 3-way option structure that provides 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 24% of our net natural gas exposure through a combination of AECO swaps at C$2.37/mcf and NYMEX swaps at US$3.10/mmbtu.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For 2019, we expect to deliver 11,000 bbl/d (approximately 40%) of our heavy oil volumes to market by rail, up from 9,000 bbl/d in 2018. Commencing January 1, 2019, approximately 70% of our crude by rail commitments are WTI based contracts with no WCS pricing exposure. In addition, we have entered into WCS differential hedges on approximately 10% of our net heavy oil exposure at a WTI-WCS differential of US$17.34/bbl.

A complete listing of our financial derivative contracts can be found in Note 19 to our 2018 financial statements.

Outlook for 2019

Stronger Commodity Prices

Following the pricing challenges of the fourth quarter, global benchmark prices have recently improved with WTI currently trading at US$57/bbl, as compared to a low of US$42/bbl in December 2018. In addition, following the Government of Alberta's announcement on December 2, 2018 of temporary production curtailments, Canadian light and heavy oil differentials have narrowed substantially. In Q1/2019, the WTI-WCS price differential averaged US$12.29/bbl and the WTI-MSW price differential averaged US$4.85/bbl. This combination of improved WTI prices and the narrowing of Canadian differentials are expected to have a positive impact to our adjusted funds flow.

Free cash flow and debt repayment

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.

Based on the forward strip for 2019, our adjusted funds flow forecast has increased by 32%, from $605 million in December 2018, to approximately $800 million, which will support our debt reduction initiative. Our plan for year end is to reduce our net debt to EBITDA ratio to approximately 2.2x. As we continue to drive debt levels down, we will be positioned to enhance shareholder returns through a combination of organic growth through disciplined capital allocation, the reinstatement of a dividend and/or share buybacks.

Corporate level production volumes are strong

As a result of current activity levels, excellent well performance in the Eagle Ford and outstanding operating efficiency across all of our assets, Q1/2019 volumes are trending above 97,000 boe/d.

Activity levels are on pace for $155 million capex in Q1/2019

Approximately 33% of Q1/2019 corporate capital investment is being directed to the Eagle Ford while 52% is allocated to the Viking light oil assets. We continue to see approximately 3 drilling rigs and 1.5 frac crews in the Eagle Ford and 5 rigs and 1.5 completion crews in the Viking. With our usual seasonal slowdown in Canada during the second quarter, this puts us on track for the full year to drill approximately 245 net wells (85% extended reach horizontals) in the Viking and bring approximately 30 net wells on production in the Eagle Ford. We are executing a small heavy oil development program through the first half of 2019, with the potential to scale activity higher should oil prices and visibility to egress improve.

East Shale Duvernay appraisal progress

In Q1/2019, we are drilling four wells at Pembina with completion activities scheduled for Q2/2019. Successful tests from the four wells will increase total delineated Pembina acreage to 100 to 125 sections.

Guidance

Our 2019 production guidance range is unchanged at 93,000 to 97,000 boe/d with budgeted exploration and development capital expenditures of $550 to $650 million.

The following table summarizes our 2019 annual guidance.

Exploration and development capital ($ millions)	$550 - $650
Production (boe/d)	93,000 - 97,000
Adjusted Funds Flow ($ millions) (1)	$800
Adjusted Funds Flow per Share (2)	$1.42
Operating Netback ($/boe) (1)	$26.00
Expenses:	
Royalty rate (%)	20%
Operating ($/boe)	$10.75 - $11.25
Transportation ($/boe)	$1.25 - $1.35
General and administrative ($ millions)	$44 ($1.27/boe)
Interest ($ millions)	$112 ($3.23/boe)
Leasing expenditures ($ millions)	$7
Asset retirement obligations ($ millions)	$17

(1) Pricing assumptions: WTI - US$57/bbl; LLS - US$63/bbl; WCS differential - US$17/bbl; MSW differential – US$8/bbl, NYMEX Gas - US$2.90/mcf; AECO Gas - $1.60/mcf and Exchange Rate (CAD/USD) - 1.32.
(2) Based on weighted average common shares outstanding of 562 million.

The following table summarizes our 2019 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	$30.1	$24.2
Change of US$1.00/bbl WCS heavy oil differential	$8.3	$8.3
Change of US$1.00/bbl MSW light oil differential	$9.8	$9.8
Change of US$0.25/mcf NYMEX natural gas	$9.3	$7.4
Change of $0.01 in the CAD//USD exchange rate	$8.1	$8.1

Board and Management Changes

Baytex has an ongoing board renewal process led by the Nominating and Governance Committee of the Board. As part of this renewal process, Ray Chan and Gary Bugeaud have decided to not stand for election as directors at our 2019 Annual Meeting of Shareholders to be held in May 2019.

Mr. Chan has been instrumental in guiding Baytex over the last twenty plus years, serving numerous executive positions during this time, including nearly 10 years as Chairman. Mr. Chan has always operated with the highest integrity. His hard work, dedication and thoughtful guidance for the benefit of all stakeholders is greatly appreciated.

Baytex would also like to thank Mr. Bugeaud, who has been involved with Raging River and its predecessor companies for the last 15 years.

Rick Ramsay, our Executive Vice President and Chief Operating Officer, has elected to retire on April 5, 2019. Mr. Ramsay has been with Baytex since January 2010 and has been a key leader for the organization, managing the successful development of our Peace River assets and subsequently guiding all of our North American operations. Baytex would like to thank Mr. Ramsay for his outstanding contributions and wish him well in retirement.

Jason Jaskela will assume the role of Executive Vice President and Chief Operating Officer on April 5, 2019. Mr. Jaskela is a professional engineer with 19 years of industry experience. Previously, he was Chief Operating Officer of Raging River from March 2014 until August 2018 and the Vice President, Production from March 2012 until March 2014.

Year-end 2018 Reserves

Baytex's year-end 2018 proved and probable reserves were evaluated by Sproule Associates Limited ("Sproule"), Ryder Scott Company, L.P. ("Ryder Scott") and GLJ Petroleum Consultants ("GLJ"), all independent qualified reserves evaluators. Sproule evaluated our Canadian reserves, other than the reserves associated with our Duvernay assets. GLJ evaluated the reserves associated with our Duvernay assets. Our United States properties were evaluated by Ryder Scott. Each evaluator used Sproule's December 31, 2018 forecast price and cost assumptions.

All of our oil and gas properties were evaluated or audited in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"). Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2018, which will be filed on or before March 31, 2019.

On August 22, 2018, Baytex and Raging River completed a strategic combination. Our 2018 reserves report reflects this strategic combination with a meaningful increase in our light oil reserves in Canada.

2018 Highlights

- Proved developed producing ("PDP") reserves increased by 35%, from 100 mmboe to 135 mmboe. Proved reserves ("1P") increased by 23%, from 256 mmboe to 315 mmboe. Proved plus probable reserves ("2P") increased by 22%, from 432 mmboe to 527 mmboe.

- Reserves associated with the Raging River assets increased by 4% on a 2P basis to 111 mmboe, as compared to year-end 2017. The Raging River combination enhanced the quality of Baytex's reserves base, adding high value light oil reserves in the Viking and Duvernay.

- Replaced 106% of total 2018 production, adding 31 mmboe of 2P reserves through development activities. Inclusive of the Raging River transaction, replaced 422% of total 2018 production with 124 mmboe of 2P reserves additions.

- Reserves on a 1P basis are comprised of 83% oil and NGL (40% light oil, 23% NGL's, 16% heavy oil and 4% bitumen) and 17% natural gas.

- PDP reserves represent 43% of 1P reserves (39% at year-end 2017) and 1P reserves represent 60% of 2P reserves (59% at year-end 2016).

- Finding and Development ("F&D") costs, including changes in future development capital ("FDC"), were $15.82/boe for PDP reserves and $20.11/boe for 2P reserves. Generated a PDP recycle ratio of 1.5x based on our 2018 operating netback of $23.76/boe.

- Finding, development and acquisition costs ("FD&A") costs, including changes in FDC, were $25.55/boe for 2P reserves.

- Baytex maintains a strong reserves life index ("RLI") of 8.7 years based on 1P reserves and 14.6 years based on 2P reserves.

- At year-end, 2018, the present value of our reserves, discounted at 10% before tax, is estimated to be $6.2 billion (as compared to $4.1 billion at year-end 2017). The increase is largely attributable to the Strategic Combination.

- Our net asset value at year-end 2018, discounted at 10%, is estimated to be $7.27 per share. This is based on the estimated reserves value of $6.2 billion plus a value for undeveloped acreage, net of long-term debt, asset retirement obligations and working capital.

Petroleum and Natural Gas Reserves as at December 31, 2018

The following table sets forth our gross and net reserves volumes at December 31, 2018 by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in the table may not add due to rounding.

CANADA	**Forecast Prices and Costs**					
	Light and Medium Oil		**Tight Oil**		**Heavy Oil**	
Reserves Category	**Gross[(1)] (mbbl)**	**Net[(2)] (mbbl)**	**Gross[(1)] (mbbl)**	**Net[(2)] (mbbl)**	**Gross[(1)] (mbbl)**	**Net[(2)] (mbbl)**
Proved						
Developed Producing	30,987	29,089	740	652	24,922	20,092
Developed Non-Producing	263	256	—	—	1,161	1,006
Undeveloped	40,296	37,584	1,360	1,191	23,530	20,668
Total Proved	71,545	66,929	2,099	1,843	49,613	41,766
Probable	20,941	19,352	3,254	2,730	42,687	35,726
Total Proved Plus Probable	92,487	86,281	5,353	4,572	92,301	77,492

CANADA	**Forecast Prices and Costs**					
	Bitumen		**Natural Gas Liquids[(3)]**		**Conventional Natural Gas[(4)]**	
Reserves Category	**Gross[(1)] (mbbl)**	**Net[(2)] (mbbl)**	**Gross[(1)] (mbbl)**	**Net[(2)] (mbbl)**	**Gross[(1)] (mmcf)**	**Net[(2)] (mmcf)**
Proved						
Developed Producing	1,934	1,478	1,401	1,070	55,986	50,308
Developed Non-Producing	7,746	7,008	3	3	1,943	1,533
Undeveloped	3,126	2,712	1,628	1,340	52,628	47,699
Total Proved	12,805	11,198	3,032	2,412	110,557	99,540
Probable	55,545	43,284	3,848	3,013	98,032	87,376
Total Proved Plus Probable	68,350	54,482	6,880	5,425	208,589	186,915

CANADA	**Forecast Prices and Costs**			
	Shale Gas		**Oil Equivalent[(5)]**	
Reserves Category	**Gross[(1)] (mmcf)**	**Net[(2)] (mmcfl)**	**Gross[(1)] (mboe)**	**Net[(2)] (mboe)**
Proved				
Developed Producing	1,432	1,310	69,553	60,983
Developed Non-Producing	—	—	9,497	8,528
Undeveloped	1,890	1,724	79,026	71,732
Total Proved	3,321	3,034	158,075	141,243
Probable	5,506	4,968	143,532	119,495
Total Proved Plus Probable	8,828	8,002	301,607	260,738

UNITED STATES	Forecast Prices and Costs					
	Tight Oil		Natural Gas Liquids[3]		Shale Gas	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mmcf)	Net[2] (mmcf)
Proved						
Developed Producing	18,348	13,445	31,512	23,309	66,901	49,572
Developed Non-Producing	38	28	214	158	566	417
Undeveloped	32,334	23,700	39,856	29,312	80,367	59,166
Total Proved	50,720	37,174	71,582	52,779	147,835	109,155
Probable	18,625	13,680	34,625	25,441	66,043	48,502
Total Proved Plus Probable	69,345	50,854	106,207	78,220	213,878	157,657

UNITED STATES	Forecast Prices and Costs			
	Conventional Natural Gas[4]		Oil Equivalent[5]	
Reserves Category	Gross[1] (mmcf)	Net[2] (mmcf)	Gross[1] (mboe)	Net[2] (mbbl)
Proved				
Developed Producing	24,993	18,357	65,176	48,076
Developed Non-Producing	49	36	354	261
Undeveloped	32,506	23,803	91,002	66,841
Total Proved	57,548	42,197	156,532	115,178
Probable	24,652	18,147	68,366	50,229
Total Proved Plus Probable	82,200	60,344	224,898	165,407

TOTAL	Forecast Prices and Costs					
	Light and Medium Oil		Tight Oil		Heavy Oil	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)
Proved						
Developed Producing	30,987	29,089	19,088	14,097	24,922	20,092
Developed Non-Producing	263	256	38	28	1,161	1,006
Undeveloped	40,296	37,584	33,693	24,891	23,530	20,668
Total Proved	71,545	66,929	52,819	39,016	49,613	41,766
Probable	20,941	19,352	21,879	16,410	42,687	35,726
Total Proved Plus Probable	92,487	86,281	74,698	55,426	92,301	77,492

TOTAL	Forecast Prices and Costs					
	Bitumen		Natural Gas Liquids[3]		Shale Gas	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mmcf)	Net[2] (mmcf)
Proved						
Developed Producing	1,934	1,478	32,912	24,379	68,333	50,882
Developed Non-Producing	7,746	7,008	217	160	566	417
Undeveloped	3,126	2,712	41,484	30,652	82,257	60,890
Total Proved	12,805	11,198	74,614	55,191	151,156	112,188
Probable	55,545	43,284	38,473	28,454	71,550	53,471
Total Proved Plus Probable	68,350	54,482	113,087	83,645	222,706	165,659

TOTAL

	Forecast Prices and Costs			
	Conventional Natural Gas[4]		Oil Equivalent[5]	
Reserves Category	Gross[1] (mmcf)	Net[2] (mmcf)	Gross[1] (mboe)	Net[2] (mboe)
Proved				
Developed Producing	80,980	68,665	134,729	109,059
Developed Non-Producing	1,991	1,569	9,851	8,789
Undeveloped	85,133	71,502	170,028	138,572
Total Proved	168,104	141,736	314,607	256,421
Probable	122,685	105,523	211,898	169,724
Total Proved Plus Probable	290,789	247,259	526,505	426,145

Notes:

(1) “Gross” reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) “Net” reserves means Baytex's gross reserves less all royalties payable to others.

(3) Natural Gas Liquids includes condensate.

(4) Conventional Natural Gas includes associated, non-associated and solution gas.

(5) 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.

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in table may not add due to rounding.

Reconciliation of Gross Reserves [1][2]
By Principal Product Type
Forecast Prices and Costs

	Heavy Oil			Bitumen		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**
December 31, 2017	46,706	39,757	86,463	13,266	55,726	68,992
Extensions	1,282	690	1,972	—	—	—
Infill Drilling	1,346	905	2,251	—	—	—
Improved Recoveries	1,952	4,621	6,574	—	—	—
Technical Revisions [3]	4,315	(4,922)	(607)	(205)	(178)	(382)
Discoveries	2	2	4	—	—	—
Acquisitions [4]	3,080	1,522	4,602	—	—	—
Dispositions	(1)	(2)	(2)	—	—	—
Economic Factors	149	114	262	—	(3)	(3)
Production	(9,218)	—	(9,218)	(256)	—	(256)
December 31, 2018	49,613	42,687	92,301	12,805	55,545	68,350

	Light and Medium Crude Oil			Tight Oil		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**
December 31, 2017	1,608	1,225	2,833	50,296	11,390	61,686
Extensions [4]	—	—	—	1,515	2,645	4,160
Infill Drilling [4]	10,823	2,856	13,679	1,062	147	1,209
Improved Recoveries	—	—	—	—	—	—
Technical Revisions [3]	273	(381)	(109)	5,285	7,154	12,438
Discoveries	—	—	—	65	15	80
Acquisitions [4]	61,992	17,234	79,226	625	594	1,219
Dispositions	—	—	—	—	—	—
Economic Factors	15	8	23	(175)	(65)	(240)
Production	(3,165)	—	(3,165)	(5,854)	—	(5,854)
December 31, 2018	71,545	20,941	92,487	52,819	21,879	74,698

	Natural Gas Liquids[5]			Shale Gas		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mmcf)**	**Probable (mmcf)**	**Proved + Probable (mmcf)**
December 31, 2017	84,564	38,962	123,526	172,855	75,686	248,541
Extensions [4]	644	1,173	1,817	2,582	4,681	7,262
Infill Drilling	534	109	643	407	121	528
Improved Recoveries	—	—	—	—	—	—
Technical Revisions [3]	(5,742)	(1,716)	(7,458)	(10,715)	(9,111)	(19,826)
Discoveries	12	3	15	73	17	90
Acquisitions [4]	349	256	605	790	809	1,599
Dispositions	—	—	—	—	—	—
Economic Factors	(528)	(314)	(841)	(1,133)	(652)	(1,785)
Production	(5,220)	—	(5,220)	(13,702)	—	(13,702)
December 31, 2018	74,614	38,473	113,087	151,156	71,550	222,706

Gross Reserves Category	Conventional Natural Gas[6] Proved (mmcf)	Conventional Natural Gas[6] Probable (mmcf)	Conventional Natural Gas[6] Proved + Probable (mmcf)	Oil Equivalent[7] Proved (mboe)	Oil Equivalent[7] Probable (mboe)	Oil Equivalent[7] Proved + Probable (mboe)
December 31, 2017	181,837	100,724	282,560	255,556	176,461	432,017
Extensions [4]	66	185	251	3,882	5,319	9,201
Infill Drilling [4]	6,055	1,643	7,699	14,842	4,311	19,153
Improved Recoveries	—	—	—	1,952	4,621	6,574
Technical Revisions [3]	(24,918)	9,915	(15,004)	(2,013)	91	(1,922)
Discoveries	—	—	—	92	22	114
Acquisitions [4]	28,494	11,812	40,306	70,926	21,709	92,635
Dispositions	—	—	—	(1)	(2)	(2)
Economic Factors	(3,197)	(1,593)	(4,790)	(1,261)	(635)	(1,896)
Production	(20,232)	—	(20,232)	(29,368)	—	(29,368)
December 31, 2018	168,104	122,685	290,789	314,607	211,898	526,505

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) Reserves information as at December 31, 2018 and 2017 is prepared in accordance with NI 51-101.

(3) Negative technical revisions for conventional natural gas are largely the result of adjustments to our gas conservation bookings in Peace River area and reduced type well profiles in our Canadian conventional natural gas properties. Positive technical revisions for tight oil are the result of enhanced type well profiles on our Eagle Ford acreage, as well as the reclassification of some natural gas liquids volumes to tight oil. Negative technical revisions for shale gas and natural gas liquids are the result of the removal of certain drilling locations on our Eagle Ford acreage as well as reclassification of shale gas volumes to solution gas.

(4) Acquisitions are principally attributable to reserves associated with the Raging River combination. For light and medium crude oil and tight oil, reserves associated with the Raging River assets are captured within acquisitions, extensions and infill drilling. Total proved reserves of 11.5 mmboe and total proved plus probable reserves of 14.6 mmboe of the infill drilling additions are associated with the Raging River Acquisition. Total proved reserves of 2.6 mmboe and total proved plus probable reserves of 7.2 mmboe of the extensions additions are associated with the Raging River Acquisition.

(5) Natural gas liquids include condensate.

(6) Conventional natural gas includes associated, non-associated and solution gas.

(7) 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.

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2018 by annualized Q4/2018 production.

	Q4/2018 Actual Production	Reserves Life Index (years) Proved	Reserves Life Index (years) Proved Plus Probable
Oil and NGL (bbl/d)	81,653	8.8	14.8
Natural Gas (mcf/d)	103,424	8.5	13.6
Oil Equivalent (boe/d)	98,890	8.7	14.6

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent qualified reserves evaluators, the efficiency of our capital program is summarized in the following table.

	2018	2017	2016	Three-Year Total / Average 2016 - 2018
Capital Expenditures ($ millions)				
Exploration and development	$ 495.7	$ 326.3	$ 224.8	$ 1,046.8
Acquisitions (net of dispositions)	1,603.9	59.9	(63.6)	1,600.2
Total	$ 2,099.6	$ 386.1	$ 161.2	$ 2,646.9
Change in Future Development Costs – 1P ($ millions)				
Exploration and development	$ 117.4	$ (132.6)	$ (219.4)	$ (234.6)
Acquisitions (net of dispositions)	870.0	35.5	7.6	913.1
Total	$ 987.4	$ (97.1)	$ (211.8)	$ 678.4
Change in Future Development Costs – 2P ($ millions)				
Exploration and Development	$ 132.3	$ (76.4)	$ 108.8	$ 164.7
Acquisitions (net of dispositions)	932.2	160.6	1.9	1,094.6
Total	$ 1,064.5	$ 84.2	$ 110.7	$ 1,259.4
PDP Reserves Additions (mboe)				
Exploration and development	31,330	23,752	17,120	72,202
Acquisitions (net of dispositions)	32,398	3,711	(1,710)	34,399
Total	63,728	27,463	15,410	106,601
1P Reserves Additions (mboe)				
Exploration and development	17,494	21,695	5,041	44,243
Acquisitions (net of dispositions)	70,925	6,821	(1,564)	76,168
Total	88,419	28,516	3,477	120,411
2P Reserves Additions (mboe)				
Exploration and development	31,224	34,398	17,253	82,895
Acquisitions (net of dispositions)	92,633	17,204	(2,408)	107,409
Total	123,857	51,602	14,845	190,304
F&D costs ($/boe) (1)				
PDP	$ 15.82	$ 13.73	$ 13.14	$ 14.50
1P	$ 35.05	$ 8.93	$ 1.07	$ 18.36
2P	$ 20.11	$ 7.26	$ 19.33	$ 14.61
FD&A costs ($/boe) (2)				
PDP	$ 32.95	$ 14.06	$ 10.50	$ 24.83
1P	$ 34.91	$ 10.13	$ — (5)	$ 27.62
2P	$ 25.55	$ 9.11	$ 18.33	$ 20.53
Ratios (based on 2P reserves)				
Production replacement ratio (3)	422%	201%	58%	237%
Recycle ratio (4)	1.2x	2.7x	0.9x	1.6x

Notes:

(1) F&D costs are calculated as total exploration and development expenditures (excluding acquisition and divestitures and including the change in FDC) divided by reserves additions from exploration and development activity.

(2) FD&A costs are calculated as total capital expenditures (including acquisition and divestitures and the change in FDC) divided by total reserves additions.

(3) Production Replacement Ratio is calculated as total reserves additions divided by total annual production (including acquisitions and divestitures).

(4) Recycle Ratio is calculated as operating netback divided by 2P F&D costs. Operating netback is calculated as revenue less royalties, operating expenses and transportation expenses.

(5) 2016 FD&A costs (1P) were negative due to the reduction in estimated Future Development Costs.

Net Present Value of Reserves (Forecast Prices and Costs)

The following table summarizes our independent reserves evaluators estimates of the net present value before income taxes of the future net revenue attributable to our reserves using Sproule's forecast prices and costs (and excluding the impact of any hedging activities). Please note that the data in the table may not add due to rounding.

Summary of Net Present Value of Future Net Revenue
As at December 31, 2018
Forecast Prices and Costs
Before Income Taxes and Discounted at (%/year)

CANADA

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,792,884	$ 1,544,771	$ 1,355,997	$ 1,212,741	$ 1,101,425
Developed Non-Producing	244,486	172,472	125,171	93,194	70,965
Undeveloped	1,841,321	1,279,571	907,327	654,251	476,320
Total Proved	3,878,692	2,996,814	2,388,494	1,960,186	1,648,709
Probable	3,862,671	2,304,632	1,538,566	1,108,674	841,887
Total Proved Plus Probable	$ 7,741,363	$ 5,301,446	$ 3,927,060	$ 3,068,859	$ 2,490,597

UNITED STATES

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,627,506	$ 1,192,348	$ 961,733	$ 820,072	$ 723,542
Developed Non-Producing	8,652	6,491	5,164	4,286	3,667
Undeveloped	1,667,167	1,099,049	759,576	542,510	396,760
Total Proved	3,303,324	2,297,888	1,726,473	1,366,868	1,123,969
Probable	1,750,388	901,795	531,484	343,816	238,512
Total Proved Plus Probable	5,053,712	3,199,683	2,257,957	1,710,684	1,362,481

TOTAL

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 3,420,390	$ 2,737,119	$ 2,317,729	$ 2,032,813	$ 1,824,967
Developed Non-Producing	253,138	178,963	130,335	97,480	74,631
Undeveloped	3,508,488	2,378,620	1,666,903	1,196,760	873,080
Total Proved	7,182,016	5,294,702	4,114,967	3,327,054	2,772,678
Probable	5,613,059	3,206,427	2,070,050	1,452,489	1,080,399
Total Proved Plus Probable	12,795,075	8,501,129	6,185,017	4,779,543	3,853,078

Sproule Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2018.

Year	WTI Cushing US$/bbl	LLS Onshore US$/bbl	Canadian Light Sweet $/bbl	Western Canada Select C$/bbl	Henry Hub US$/MMbtu	AECO C Spot C$/MMbtu	Operating Cost Inflation Rate %/Yr	Capital Cost Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2018 act.	65.04	70.14	68.63	52.64	3.11	1.52	2.5	4.2	0.77
2019	63.00	68.40	75.27	59.47	3.00	1.95	0.0	0.0	0.77
2020	67.00	70.37	77.89	62.31	3.25	2.44	2.0	2.0	0.80
2021	70.00	71.34	82.25	67.45	3.50	3.00	2.0	2.0	0.80
2022	71.40	72.76	84.79	69.53	3.57	3.21	2.0	2.0	0.80
2023	72.83	74.22	87.39	71.66	3.64	3.30	2.0	2.0	0.80
2024	74.28	75.70	89.14	73.10	3.71	3.39	2.0	2.0	0.80
2025	75.77	77.22	90.92	74.56	3.79	3.49	2.0	2.0	0.80
2026	77.29	78.76	92.74	76.05	3.86	3.58	2.0	2.0	0.80
2027	78.83	80.34	94.60	77.57	3.94	3.68	2.0	2.0	0.80
2028	80.41	81.94	96.49	79.12	4.02	3.78	2.0	2.0	0.80
2029	82.02	83.58	98.42	80.70	4.10	3.88	2.0	2.0	0.80
Thereafter				Escalation rate of 2.0%					

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below.

Future Development Costs
As of December 31, 2018
Forecast Prices and Costs
($000s)

	CANADA		UNITED STATES		TOTAL	
	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves
2019	302,027	361,583	129,181	144,727	431,208	506,309
2020	457,359	633,766	292,260	292,260	749,619	926,025
2021	400,568	487,702	264,263	264,263	664,831	751,965
2022	276,701	451,347	273,975	273,975	550,676	725,323
2023	10,499	216,289	240,502	241,144	251,002	457,433
Remaining	1,414	308,388	16,398	559,839	17,812	868,227
Total (undiscounted)	1,448,569	2,459,074	1,216,580	1,776,209	2,665,148	4,235,283

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2018.

	Undeveloped Acres	
	Gross	Net
Alberta	1,054,743	964,579
Saskatchewan	369,366	329,641
Total	1,424,109	1,294,220

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2018. We estimate the value of our net undeveloped land holdings at December 31, 2018 to be approximately $164.6 million, as compared to $75.9 million as at December 31, 2017. This internal evaluation generally represents the estimated replacement cost of our undeveloped land, excluding the approximately 98,952 net acres of our undeveloped land that we expect to expire on or before December 31, 2019. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown land sales for properties in the vicinity of our undeveloped land holdings.

Net Asset Value

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by the Company's independent reserves engineers at year-end, plus the estimated value of our undeveloped land holdings, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions. In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development.

The following table sets forth our net asset value as at December 31, 2018.

	Net Asset Value Forecast Prices and Costs Before Income Taxes and Discounted at (%/year)		
($ millions except per share amounts)	**5%**	**10%**	**15%**
Total net present value of proved plus probable reserves (before tax)	$ 8,501	$ 6,185	$ 4,780
Undeveloped land holdings (1)	165	165	165
Asset retirement obligations (2)	(147)	(57)	(36)
Net debt	(2,265)	(2,265)	(2,265)
Net Asset Value	$ 6,254	$ 4,028	$ 2,644
Net Asset Value per Share (3)	$ 11.29	$ 7.27	$ 4.77

Notes:

(1) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
(2) Asset retirement obligations may not equal the amount shown on the statement of financial position as a portion of these costs are already reflected in the present value of proved plus probable reserves and the discount rates applied differ.
(3) Based on 554.1 million common shares outstanding as at December 31, 2018.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2018 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. MST (11:00 a.m. EST)

Baytex will host a conference call today, March 6, 2019, starting at 9:00am MST (11:00am EST). 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/baytexq420190306.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 current oil prices will have a very positive impact on our adjusted funds flow; that we will strengthen our balance sheet in 2019; the trend for our production volumes; our expected Q1/2019 capital expenditures; that 80% of our capital spending will be directed to high operating netback assets in the Eagle Ford and Viking; our forecast adjusted funds flow, debt repayment, production and net debt to EBITDA ratio for 2019; that 90% of our production is the Viking and Duvernay is light oil; that 2018 repositioned us to have strong free cash flow; our Eagle Ford assets, including our assessment that: it is a premier oil resource play, generates strong operating netbacks and free cash flow and has a significant development inventory; that our extended reach horizontal wells are economic; that our Peace River assets generate some of the strongest capital efficiencies in the oil and gas industry; that we continue to prudently advance the delineation of our East Duvernay Shale assets; that we expect to request an extension to our credit facilities in 2019; 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 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; the expected impact of improved pricing on our adjusted funds flow; that deleveraging remains a priority and our planned uses for adjusted funds flow in 2019; for the Eagle Ford and Viking in Q1/2019: the percentage of our capital spending directed to the assets and the number of drilling rigs and frac crews on our lands; the number of wells to be drilled in the Viking in 2019; the number of wells to be brought on production in the Eagle Ford in 2019; that we will execute a small heavy oil program in the first half of 2019 that could move higher if prices and egress improve; for the East Duvernay Shale in 2019: that we will continue to prudently advance its evaluation, that we will drill four wells in Q1/2019 that if successful will delineate 100 to 125 sections of land; our 2019 production, capital expenditure guidance, adjusted funds flow, adjusted funds flow per share and operating netback guidance; our expected royalty rate and operating, transportation, general and administration and interest expenses for 2019; our expected leasing expenditures and asset retirement obligation spending for 2019; the sensitivity of our 2019 Adjusted Funds Flow to changes in WTI, WCS, MSW and NYMEX prices and the C$/US$ exchange rate; our reserves life index; the net present value before income taxes of the future net revenue attributable to our reserves; forecast prices for petroleum and natural gas; forecast inflation and exchange rates; future development costs; the value of our undeveloped land holdings and our estimated net asset value. 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, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2019 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, asset retirement obligations settled and transaction costs. 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. Transaction costs associated with the Raging River combination are excluded from adjusted funds flow as we consider the costs non-recurring and not reflective of our ability to generate adjusted funds flow on an ongoing 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 months and year ended December 31, 2018.*

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 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 and provides a key measure to assess our liquidity. The current portion of financial derivatives is excluded as the valuation of the underlying contracts is subject to a high degree of volatility prior to the ultimate settlement. Onerous contracts are excluded from net debt as the underlying contracts do not represent an available source of 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.

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

Advisory Regarding Oil and Gas Information

The reserves information contained in this press release has been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2018, which will be filed on or before March 31, 2019. Listed below are cautionary statements that are specifically required by NI 51-101:

- *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.*

- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*

- *This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.*

This press release contains metrics commonly used in the oil and natural gas industry, such as “recycle ratio,” “operating netback,” and “reserves life index.” These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this press release to provide readers with additional measures to evaluate Baytex’s performance, however, such measures are not reliable indicators of Baytex’s future performance and future performance may not compare to Baytex’s performance in previous periods and therefore such metrics should not be unduly relied upon.

This press release discloses drilling locations for our East Duvernay Shale assets. Drilling locations refer to Baytex’s total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves and are derived from our most recent independent reserves evaluation dated as at December 31, 2018. Potential drilling opportunities are unbooked locations that 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. In the East Duvernay Shale, Baytex's net drilling locations for the East Duvernay Shale assets include 6 proved, 9 probable and 160 unbooked locations.

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.

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers *disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this press release may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.*

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this press release may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

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:

Brian Ector, Vice President, Capital Markets

Toll Free Number: 1-800-524-5521
Email: investor@baytexenergy.com