BAYTEX

ENERGY CORP.

BAYTEX ANNOUNCES 2019 YEAR END RESERVES AND PRELIMINARY FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA (January 20, 2020) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) announces its year-end 2019 reserves and 2019 fourth quarter and year-end preliminary unaudited financial and operating results (all amounts are in Canadian dollars unless otherwise noted).

"Our production in 2019 exceeded the high end of our annual guidance with outstanding capital efficiencies in our development program. As a result, we generated $329 million of free cash flow and a 17% reduction in net debt. Each of our core properties (Eagle Ford, Viking and Heavy Oil) contributed substantial asset level free cash flow. We also achieved a strong year of reserves development with proved developed producing reserves increasing 5% with finding & development costs of $13.04/boe and a recycle ratio of 2.3x. We are building on this momentum in 2020 as we continue to maximize free cash flow and further strengthen our balance sheet," commented Ed LaFehr, President and Chief Executive Officer.

Preliminary Financial and Operating Highlights

We will release our 2019 fourth quarter and year-end audited financial and operating results on March 4, 2020. In conjunction with the release of our 2019 reserves, we are providing preliminary unaudited financial and operating results.

- Generated production of 96,360 boe/d (83% oil and NGL) during Q4/2019 and 97,680 boe/d for full-year 2019, exceeding the high end of guidance.
- Exploration and development expenditures totaled $153 million in Q4/2019, bringing aggregate spending for 2019 to $552 million, which is at the low end of our original guidance.
- Delivered adjusted funds flow of $232 million ($0.42 per basic share) in Q4/2019 and $902 million ($1.62 per basic share) for the full-year 2019.
- Generated EBITDA of $256 million in Q4/2019 and $1.01 billion for the full-year 2019.
- Reduced net debt by $100 million in Q4/2019 and by $394 million in 2019 as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar. Net debt totaled $1.87 billion at December 31, 2019.
- Maintained strong financial liquidity with our credit facilities approximately 50% undrawn and $524 million of liquidity at year-end 2019.
- Realized an operating netback (inclusive of hedging) of $29.89/boe in Q4/2019 and $29.47/boe for the full-year 2019.

Reserves Highlights

- Proved developed producing ("PDP") reserves increased by 5%, from 135 mmboe to 142 mmboe while proved reserves ("1P") and proved plus probable reserves ("2P") are largely unchanged at 314 mmboe (315 mmboe at year-end 2018) and 529 mmboe (527 mmboe at year-end 2018), respectively.
- Replaced 112% of 2019 production, adding 40 mmboe of 2P reserves through development activities.
- Finding and development ("F&D") costs, including changes in future development costs ("FDC"), were $13.04/boe for PDP reserves, $12.92/boe for 1P reserves and $16.30/boe for 2P reserves.
- Generated a PDP and 1P recycle ratio of 2.3x and a 2P recycle ratio of 1.8x based on 2019 operating netback of $29.47/boe.
- Reserves on a 1P basis are comprised of 82% oil and NGL (37% light oil, 25% NGL's, 16% heavy oil and 4% bitumen) and 18% natural gas.
- PDP reserves represent 45% of 1P reserves (43% at year-end 2018) and 1P reserves represent 59% of 2P reserves (60% at year-end 2018).

- Baytex maintains a strong reserves life index of 8.9 years based on 1P reserves and 15.1 years based on 2P reserves.
- Our net asset value at year-end 2019, discounted at 10%, is estimated to be $6.97 per share. This is based on the estimated reserves value plus a value for undeveloped acreage, net of long-term debt and working capital.

2019 Preliminary Financial and Operating Results

The following are our certain preliminary unaudited results for the year ended December 31, 2019.

Preliminary Operating Results	**Fourth Quarter 2019**	**Year Ended December 31, 2019**
Daily Production		
Light oil and condensate (bbl/d)	43,906	43,587
Heavy oil (bbl/d)	27,050	26,741
NGL (bbl/d)	8,699	10,229
Total liquids (bbl/d)	**79,655**	**80,557**
Natural gas (mcf/d)	100,235	102,742
Oil equivalent (boe/d @ 6:1) (1)	**96,360**	**97,680**

	Fourth Quarter 2019		**Year Ended December 31, 2019**	
Preliminary Financial Results (2)	**$ millions**	**$/boe**	**$ millions**	**$/boe**
Total sales, net of blending and other expenses (3)	$428	$48.25	$1,737	$48.72
Royalties	(77)	(8.72)	(320)	(8.98)
Operating expense	(100)	(11.23)	(398)	(11.16)
Transportation expense	(9)	(1.00)	(44)	(1.23)
Operating netback (4)	**$242**	**$27.30**	**$975**	**$27.35**
General and administrative	(10)	(1.12)	(45)	(1.28)
Cash financing and interest	(24)	(2.75)	(107)	(3.01)
Realized financial derivatives gain (loss)	23	2.59	76	2.12
Other (5)	1	0.16	4	0.13
Adjusted funds flow (4)	**$232**	**$26.19**	**$902**	**$25.31**
Exploration and development expenditures (4)	(153)	(17.27)	(552)	(15.49)
Asset retirement obligations	(5)	(0.51)	(15)	(0.43)
Leasing expenditures	(2)	(0.18)	(6)	(0.17)
Free cash flow (4)	**$73**	**$8.22**	**$329**	**$9.22**

Notes:

(1) 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.
(2) Data in the table may not add due to rounding.
(3) 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.
(4) The terms “adjusted funds flow”, “operating netback”, “exploration and development expenditures” and “free cash flow” 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.
(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.

Risk Management

To manage commodity price movements we utilize various financial derivative contracts and crude-by-rail to reduce the volatility in our adjusted funds flow. For 2020, we have entered into hedges on approximately 48% of our net crude oil exposure, largely utilizing a 3-way option structure on 24,500 bbl/d that provides WTI price protection at US$58.04/bbl with upside participation to US$63.06/bbl. The 3-way contracts are structured as follows:

WTI	**Baytex Receives (1)**
At or below US$50.44/bbl	WTI + US$7.60/bbl
Between US$50.44/bbl and US$58.04/bbl	US$58.04/bbl
Between US$58.04/bbl and US$63.06/bbl	WTI
Above US$63.06/bbl	US$63.06/bbl

Note:

(1) The price Baytex receives as illustrated in the table represents an average of all contracts entered into.

In addition to the 3-way options, we have WTI-based fixed price swaps on 3,500 bbl/d at US$57.40/bbl for 2020.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For 2020, we are contracted to deliver approximately 11,000 bbl/d of our heavy oil volumes to market by rail. In addition, we have entered into WCS differential hedges on 2,500 bbl/d at a WTI-WCS differential of US$16.10/bbl.

2020 Outlook

Our 2020 guidance remains unchanged as we target production of 93,000 to 97,000 boe/d with exploration and development expenditures of $500 to $575 million.

We have a high quality and diversified oil portfolio with a strong drilling inventory of approximately 10 or more years in each of our core areas (Viking, Eagle Ford and Heavy Oil). Our commitment remains to deliver stable production, generate free cash flow and further strengthen our balance sheet. Our 2020 capital expenditures program is expected to be fully funded from adjusted funds flow at a WTI price of US$50/bbl. Adjusted funds flow in excess of capital expenditures, lease payments and asset retirement obligations will be allocated to debt repayment.

Year-end 2019 Reserves

Baytex's year-end 2019 proved and probable reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated 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") using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2020. 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, 2019, which will be filed on or before March 30, 2020.

The following table sets forth our gross and net reserves volumes at December 31, 2019 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [3] (mbbls)	Conventional Natural Gas [4] (mmcf)	Shale Gas (mmcf)	Total [5] (mboe)
Gross [1]									
Proved producing	27,297	23,273	28,050	2,711	81,331	34,218	56,743	99,628	141,611
Proved developed non-producing	—	39	570	7,196	7,805	388	2,492	1,018	8,778
Proved undeveloped	33,322	32,250	22,691	1,892	90,155	43,333	45,272	133,516	163,286
Total proved	60,619	55,562	51,311	11,799	179,291	77,939	104,506	234,162	313,674
Total probable	31,218	24,139	37,805	53,743	146,905	35,654	99,816	99,739	215,818
Proved plus probable	91,837	79,701	89,116	65,542	326,196	113,592	204,323	333,901	529,492
Net [2]									
Proved producing	25,447	17,245	24,818	2,504	70,015	25,470	53,003	74,009	116,654
Proved developed non-producing	—	29	483	6,766	7,278	287	2,022	757	8,029
Proved undeveloped	31,052	24,029	20,371	1,873	77,325	32,206	40,444	99,106	132,789
Total proved	56,499	41,303	45,672	11,144	154,618	57,963	95,469	173,872	257,471
Total probable	28,703	18,214	32,813	43,031	122,761	26,797	90,061	74,952	177,060
Proved plus probable	85,201	59,517	78,486	54,175	277,379	84,760	185,530	248,823	434,531

Notes:

(1) "Gross" reserves means the total working 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 plus royalty interest reserves.

(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. Please note that the data in the table may not add due to rounding.

Proved Reserves – Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids (4) (mbbls)	Conventional Natural Gas (5) (mmcf)	Shale Gas (mmcf)	Total (6) (mboe)
December 31, 2018	71,545	52,819	49,613	12,805	186,783	74,614	168,104	151,156	314,607
Product Type Transfer (2)	—	—	—	—	—	—	(57,548)	57,548	—
Extensions	7,328	7,510	4,845	—	19,683	8,260	6,225	26,200	33,347
Technical Revisions (3)	(9,133)	1,865	9,012	(341)	1,403	2,109	8,463	21,868	8,567
Acquisitions	1,264	—	18	—	1,282	2	227	—	1,322
Dispositions	(2,347)	—	—	—	(2,347)	—	(90)	—	(2,362)
Economic Factors	(217)	(1,232)	(3,201)	118	(4,531)	(625)	(3,590)	(2,393)	(6,153)
Production	(7,822)	(5,401)	(8,977)	(784)	(22,983)	(6,421)	(17,285)	(20,216)	(35,653)
December 31, 2019	60,619	55,562	51,311	11,799	179,291	77,939	104,506	234,162	313,674

Probable Reserves – Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids (4) (mbbls)	Conventional Natural Gas (5) (mmcf)	Shale Gas (mmcf)	Total (6) (mboe)
December 31, 2018	20,941	21,879	42,687	55,545	141,052	38,473	122,685	71,550	211,898
Product Type Transfer (2)	—	—	—	—	—	—	(24,653)	24,653	—
Extensions	8,761	2,877	(363)	—	11,275	63	(473)	2,504	11,676
Technical Revisions (3)	1,696	768	(4,317)	(1,887)	(3,740)	(1,590)	2,822	5,923	(3,873)
Acquisitions	416	—	5	—	420	1	82	—	435
Dispositions	(579)	—	—	—	(579)	—	(27)	—	(583)
Economic Factors	(17)	(1,385)	(207)	85	(1,524)	(1,293)	(619)	(4,890)	(3,735)
Production	—	—	—	—	—	—	—	—	—
December 31, 2019	31,218	24,139	37,805	53,743	146,905	35,654	99,816	99,739	215,818

Proved Plus Probable Reserves – Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids (4) (mbbls)	Conventional Natural Gas (5) (mmcf)	Shale Gas (mmcf)	Total (6) (mboe)
December 31, 2018	92,487	74,698	92,301	68,350	327,836	113,087	290,789	222,706	526,505
Product Type Transfer (2)	—	—	—	—	—	—	(82,200)	82,200	—
Extensions	16,089	10,387	4,482	—	30,958	8,323	5,752	28,703	45,023
Technical Revisions (3)	(7,437)	2,634	4,695	(2,228)	(2,337)	518	11,285	27,790	4,695
Acquisitions	1,680	—	23	—	1,702	3	309	—	1,757
Dispositions	(2,926)	—	—	—	(2,926)	—	(118)	—	(2,945)
Economic Factors	(234)	(2,616)	(3,408)	204	(6,054)	(1,919)	(4,209)	(7,283)	(9,888)
Production	(7,822)	(5,401)	(8,977)	(784)	(22,983)	(6,421)	(17,285)	(20,216)	(35,653)
December 31, 2019	91,837	79,701	89,116	65,542	326,196	113,592	204,323	333,901	529,492

Notes:

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

(2) Product type transfer reflects the reclassification of solution gas in the Eagle Ford from conventional natural gas to shale gas.

(3) Positive technical revisions for heavy oil are largely the results of positive production performance versus previous forecasts in both our Lloydminster and Peace River areas. Positive conventional natural gas revisions are predominately related to the solution gas associated with our heavy oil assets. Positive technical revisions in the tight oil and shale gas are a result of enhanced type well profiles in our Eagle Ford acreage. Negative technical revisions in the light and medium oil are associated with our Viking area and are predominately a result of a reduction in later life reserves associated with the production profile.

(4) Natural gas liquids include condensate.

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

(6) 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.

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 ($ millions)	Proved Reserves	Proved Plus Probable Reserves
2020	530	536
2021	522	562
2022	563	625
2023	444	611
2024	496	848
Remainder	2	1,132
Total FDC undiscounted	2,558	4,315

F&D and FD&A Costs – including future development costs

Based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel, the efficiency of our capital program is summarized in the following table.

millions except for per boe amounts	2019	2018	2017	3 Year
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	$552.3	$495.7	$326.3	$1,374.3
Net change in Future Development Costs	$96.7	$132.3	($76.4)	$152.7
Gross Reserves additions (mmboe)	39.8	31.2	34.4	105.5
F&D Costs ($/boe)	$16.30	$20.11	$7.26	$14.48
Finding, Development & Acquisition (“FD&A”) Costs				
Exploration and development expenditures and net acquisitions	$554.5	$2,099.6	$386.1	$3,040.2
Net change in Future Development Costs	$79.9	$1,064.5	$84.2	$1,228.6
Gross Reserves additions (mmboe)	38.6	123.9	51.6	214.1
FD&A Costs ($/boe)	$16.42	$25.55	$9.11	$19.94
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	$552.3	$495.7	$326.3	$1,374.3
Net change in Future Development Costs	($90.4)	$117.4	($132.6)	($105.6)
Gross Reserves additions (mmboe)	35.8	17.5	21.7	74.9
F&D Costs ($/boe)	$12.92	$35.05	$8.93	$16.93
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$554.5	$2,099.6	$386.1	$3,040.2
Net change in Future Development Costs	($107.2)	$987.4	($97.1)	$783.1
Gross Reserves additions (mmboe)	34.7	88.4	28.5	151.7
FD&A Costs ($/boe)	$12.88	$34.91	$10.13	$25.21
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	$552.3	$495.7	$326.3	$1,374.3
Gross Reserves additions (mmboe)	42.5	31.3	23.8	97.4
F&D Costs ($/boe)	$13.04	$15.82	$13.73	$14.10
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$554.5	$2,099.6	$386.1	$3,040.2
Gross Reserves additions (mmboe)	42.5	63.7	27.5	133.7
FD&A Costs ($/boe)	$13.04	$32.95	$14.06	$22.73

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 2019 by annualized Q4/2019 production.

		Reserves Life Index (years)	
	Q4/2019 Production	Proved	Proved Plus Probable
Crude Oil and NGL (bbl/d)	79,655	8.8	15.1
Natural Gas (mcf/d)	100,234	9.3	14.7
Oil Equivalent (boe/d)	96,360	8.9	15.1

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, 2019. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2020.

Year	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil $/bbl	Western Canadian Select $/bbl	Henry Hub US$/MMbtu	AECO Spot $/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2019 act.	56.95	68.65	58.10	2.55	1.60	2.0	0.750
2020	61.00	72.64	57.57	2.62	2.04	0.0	0.760
2021	63.75	76.06	62.35	2.87	2.32	1.7	0.770
2022	66.18	78.35	64.33	3.06	2.62	2.0	0.785
2023	67.91	80.71	66.23	3.17	2.71	2.0	0.785
2024	69.48	82.64	67.97	3.24	2.81	2.0	0.785
2025	71.07	84.60	69.72	3.32	2.89	2.0	0.785
2026	72.68	86.57	71.49	3.39	2.96	2.0	0.785
2027	74.24	88.49	73.20	3.45	3.03	2.0	0.785
2028	75.73	90.31	74.80	3.53	3.09	2.0	0.785
2029	77.24	92.17	76.43	3.60	3.16	2.0	0.785
Thereafter			Escalation rate of 2.0%			2.0	0.785

Net Present Value of Reserves (1) (Forecast Prices and Costs)

The following table summarizes the McDaniel estimate of the net present value before income taxes of the future net revenue attributable to our reserves.

Reserves at December 31, 2019 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	2,640	2,501	2,211	1,965
Proved developed non-producing	179	118	81	57
Proved undeveloped	3,256	2,096	1,419	991
Total proved	6,075	4,714	3,710	3,013
Probable	5,627	3,029	1,890	1,298
Total Proved Plus Probable (before tax)	11,702	7,743	5,600	4,310

Note:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and nonproducing wells and facilities.

Net Asset Value (Forecast Prices and Costs)

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 McDaniel at year-end, plus the estimated value of our undeveloped land holdings, less net debt. 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, 2019.

($ millions, except per share amounts, discounted at)	5%	10%	15%
Net present value of proved plus probable reserves (1)	7,743	5,600	4,310
Undeveloped land holdings (2)	162	162	162
Net Debt	(1,871)	(1,871)	(1,871)
Net Asset Value	6,034	3,891	2,601
Net Asset Value per Share (3)	10.81	6.97	4.66

Notes:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and nonproducing wells and facilities.
(2) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
(3) Based on 558.3 million common shares outstanding as at December 31, 2019.

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; timing of the release 2019 fourth quarter and year-end audited financial and operating results and Annual Information Form and the contents thereof; preliminary unaudited financial and operating results; our risk management strategies; that we have strong drilling inventory of approximately ten years or more of in each of our core assets; our commitment to stable production, generation of free cash flow and further strengthening our balance sheet; that adjusted funds flow in excess of capital expenditures, lease payments and asset retirement obligations will be allocated to debt repayment; our 2020 capital program will be fully funded from adjusted funds flow at a WTI price of US$50/bbl; target production and exploration and development expenditures; corporate objectives; future development costs, F&D and FD&A; estimated net asset value; 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; 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.

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; estimated values for undeveloped acreage; 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, our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2019 to be filed not later than March 30, 2020 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. The forward-looking statements contained in this document are made as of the date hereof 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

Certain financial and operating results included in this news release, including, but not limited to, production, capital expenditures, adjusted funds flow, free cash flow, EBITDA, net debt and operating netbacks for the year ended December 31, 2019, are based on preliminary unaudited results. These results are preliminary and unaudited and are inherently uncertain and subject to change as we complete our financial statements for the year ended December 31, 2019. Given the timing of these estimates, we have not completed our customary financial closing and review procedures as at and for the three months and year ended December 31, 2019, and there can be no assurance that our final results will not differ from these estimates.

In this news release, we refer to certain financial measures (such as adjusted funds flow, EBITDA, exploration and development expenditures, free cash flow, net debt and operating netback) which do not have any standardized meaning prescribed by Canadian GAAP (“non-GAAP measures”) and are considered non-GAAP measures. While adjusted funds flow, EBITDA, exploration and development expenditures, free cash flow, net debt and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

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.

EBITDA is not a measurement based on GAAP in Canada. EBITDA is defined as net income or loss adjusted for financing and interest expenses, unrealized gains and losses on financial derivatives, income tax, non-recurring losses, payments on lease obligations, certain specific unrealized and non-cash transactions (including depletion, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation).

Exploration and development capital 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.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures discussed above), payments on lease obligations, and asset retirement obligations settled. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities. Our previous definition of free cash flow referred to sustaining capital as opposed to exploration and development expenditures. Given the current commodity price environment our exploration and development expenditures are primarily comprised of sustaining capital, which we consider the amount of exploration and development capital required to maintain production. Accordingly, we have revised our definition of free cash flow to provide clarity on the reconciliation to measures determined in accordance with GAAP.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of cash, 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 capital 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

The reserves information contained in this press release has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2019, which will be filed on or before March 30, 2020. Listed below are cautionary statements that are specifically required by NI 51-101:

- *The term barrels of oil equivalent (“boe”) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one boe (6 mcf/bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.*

- *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 “capital efficiencies”, “finding and development costs”, “finding, development and acquisition costs”, “net asset value”, “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.

Capital efficiency means the cost to drill, complete, equip and tie-in a well divided by the initial production rate of the well on a boe basis over its initial 365 days of production.

Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.

Finding, development and acquisition costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category

Net asset value has been calculated based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel effective December 31, 2019, plus the estimated value of our undeveloped land holdings, less net debt.

Recycle ratio means operating netback divided by finding and development costs for the particular reserves category.

Reserve life index means the reserves for the particular reserve category divided by annualized 2019 fourth quarter production.

This press release discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers 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. Unbooked locations 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 Eagle Ford, Baytex’s net drilling locations include 140 proved and 83 probable locations as at December 31, 2019 and 52 unbooked locations. In the Viking, Baytex’s net drilling locations include 1,080 proved and 319 probable locations as at December 31, 2019 and 636 unbooked locations. In Peace River, Baytex’s net drilling locations include 77 proved and 75 probable locations as at December 31, 2019 and 100 unbooked locations. In Lloydminster, Baytex’s net drilling locations include 178 proved and 63 probable locations as at December 31, 2019 and 361 unbooked locations. In the Duvernay, Baytex’s net drilling locations include 11 proved and 10 probable locations as at December 31, 2019 and 295 unbooked locations.

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 84% 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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